CHAPTER 7: Estimated Costs of Low-Sulfur Fuels

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This chapter presents the methodology and costs, and discusses the possible price impacts, for supplying nonroad, locomotive and marine (NRLM) diesel fuel under the final two step program. It also presents similar information for various sensitivity cases analyzed. Section 7.1 contains our analysis of the volume of NRLM diesel fuel and other distillate fuels which are affected by this program. This section also presents our estimates of the sulfur levels of NRLM diesel fuel and other fuels impacted, which is used in our emissions analysis. Section 7.2 discusses our methodology for estimating the refining costs. We present our refining cost estimates for the final rule program as well as several sensitivity cases. We also compare our cost estimates to other parties. Section 7.3 contains our estimate of the cost of adding lubricity additive to NRLM diesel fuel. Section 7.4 presents our analysis of the cost of distributing diesel fuel under this program. Section 7.5 contains a summary of the refining and distribution cost for the final rule NRLM program. Section 7.6 discusses the potential price impacts of the final NRLM program.

Table 7-1 summarizes the number of refineries we estimate will be affected by the final NRLM fuel program, as well as the total volume of NRLM fuel affected.

Table 7-1
Number of Refineries and Refining Costs for the Final NRLM Program

	Year of Program	500 ppm Fuel		15 ppm Fuel	
		All Refineries	Small Refineries	All Refineries	Small Refineries
Number of Refineries Producing 500 or 15 ppm NRLM Diesel Fuel	2007-2010	36[a]	0	0	0
	2010-2012	26	13	32	2
	2012-2014	15	13	47	2
	2014-2020	0	0	63	15
Production Volume (Million gallons per year in 2014)	2007-2010	13,327	0	0	0
	2010-2012	3,792	393	8,598	335
	2012-2014	728	393	12,247	335
	2014-2020	0	0	13,030	728

Table 2 summarizes the per gallon refining, distribution and lubricity additive costs during the various phases of the final NRLM fuel program.

Table 7-2
Summary of Fuel Costs for NRLM Fuel Control Options (cents per gallon, $2002)

Option	Specification	Year	Refining Costs (c/gal)	Distribution & Additive Costs (c/gal)	Total Costs (c/gal)
Final Rule	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm NRLM	2010-12	2.7	0.6	3.3
	500 ppm NRLM	2012-14	2.9	0.6	3.5
	15 ppm Nonroad	2010-12	5.0	0.8	5.8
	15 ppm NRLM	2012-14	5.6	0.8	6.4
	15 ppm NRLM	2014+	5.8	1.2	7.0

Table 7-3 and 7-4 summarize the potential price impacts of the final NRLM fuel program during the initial 500 ppm phase (2007-2010) and the final 15 ppm phase (2014 and beyond). Due to the uncertainty in projecting price impacts from cost estimates, we develop three potential price impacts to indicate the range of possible outcomes.

Table 7-3
Range of Possible Total Diesel Fuel Price Increases (cents per gallon)[a]

	Lower Limit	Mid-Range Estimate	Upper Limit
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2007-2010)			
PADDs 1 and 3	2.9	1.8	4.5
PADD 2	3.0	2.5	3.8
PADD 4	3.7	3.5	6.1
PADD 5	1.2	1.5	1.5
15 ppm Sulfur Cap: NRLM Fuel (fully implemented program: 2014 +)			
PADDs 1 and 3	7.7	6.3	9.8
PADD 2	7.6	7.9	11.2
PADD 4	8.2	13.0	13.9
PADD 5	5.1	6.8	7.2

[a] At a wholesale price of approximately $1.00 per gallon, these values also represent the percentage increase in diesel fuel price.

7.1 Production and Consumption of NRLM Diesel Fuel

7.1.1 Overview

This subsection describes how we estimated the distillate fuel production and demand for land-based nonroad engines, locomotives, and marine vessels that will be affected by the requirements of this final rule. This analysis also estimates the volumes of the highway diesel fuel and heating oil[A] pools which also affect or are affected by the final NRLM fuel program. Fuel production and demand are estimated for various geographic regions of interest. We begin by estimating production and consumption of various distillate fuels in 2001. We then project these volumes to 2014, which is the year in which we project per gallon costs. We selected 2014, as IRS guidelines allow refinery equipment to be depreciated over 15 years and 2014 represents the mid-point in the depreciation life of new hydrotreaters built for the 2007 500 ppm NRLM fuel cap. NRLM fuel demand is projected to increase steadily in the future. As the number of domestic refineries is not projected to increase, the economy of scale will gradually improve over time. Selecting 2014 as the year in which to project per gallon fuel costs provides a reasonable estimate of the average economies of scale which will exist with the hydrotreaters constructed in response to the rule.

These NRLM production and consumption estimates are developed for the final NRLM fuel program, as well as for a number of alternative scenarios. We then develop a set of production and consumption estimates for NRLM fuel for each year from 1996 to 2040, which are used to estimate annual emission reductions (see Chapter 3) and fuel-related costs (Sections 7.2 through 7.5 below). Finally, we estimate how the final rule and the various alternative scenarios affect the sulfur content of the various types of distillate fuel, which is again used to estimate annual emission reductions associated with each of these scenarios.

It is important early on in this discussion to define distillate fuel and how it is used. Distillate fuel is often split into three groups according to the range of temperatures at which the hydrocarbons comprising the fuel boil (boiling range). No. 1 distillate fuel is the lightest fuel, or has the lowest boiling range. Common No. 1 distillate fuels are jet fuel, No. 1 diesel fuel, and kerosene (also known as No. 1 fuel oil). No. 2 distillate fuel is somewhat heavier and has a higher boiling range, though there is significant overlap between No. 1 and No. 2 distillate fuels. No. 2 distillate fuels are usually excellent diesel fuels. Finally, No. 4 distillate fuel is the heaviest of the three, having the highest boiling range.[B] No. 4 distillate fuel is generally a poor diesel fuel and can only be used in slower speed diesel engines. This rule does not address the sulfur content of No. 4 distillate fuel. Thus, we will not address No. 4 distillate fuels in this analysis. All of these distillate fuels boil at higher temperatures than gasoline, though there is some overlap between the heaviest compounds in gasoline and the lightest compounds in No. 1 distillates.

The vast majority of the fuel used in NRLM engines falls into the No. 2 distillate fuel category. As will be seen below, a very small volume of No. 1 distillate fuel is used to fuel

[A] The term heating oil as used here represents fuel used for stationary source purposes including home heating industrial boilers, and electrical generation.

[B] There is also a No. 6 fuel, but this is usually considered a heavy fuel or heavy oil and not included in "distillate."

NRLM engines.[C] Also No. 1 distillate fuel is often blended into No. 2 distillate fuels in the winter in cold climates to avoid fuel gelling. Thus, we will address the impact of this rule on No. 1 distillate fuel in this analysis, though the primary focus will be on No. 2 distillate fuels.

The American Society of Testing and Materials (ASTM) defines three No. 2 distillate fuels: 1) low sulfur No. 2-D, 2) high sulfur No. 2-D, and 3) No. 2 fuel oil. Low sulfur No. 2-D fuel must contain 500 ppm sulfur or less, have a minimum cetane number of 40, and have a minimum cetane index limit of 40 (or a maximum aromatic content of 35 volume percent). These specifications match those set by EPA for highway diesel fuel, so essentially these ASTM limits are legal specifications. Per ASTM, both high sulfur No. 2-D and No. 2 fuel oil (heating oil) must contain no more than 5000 ppm sulfur,[D] and currently averages about 3000 ppm. The ASTM specifications for high sulfur No. 2-D fuel also include a minimum cetane number specification of 40. The ASTM specifications for high sulfur No. 2-D and No. 2 fuel oil only have the force of law in those states which have incorporated the ASTM standards in their state laws or regulations. There are no federal standards currently for these two high sulfur fuel.

We will break down No. 2-D distillate fuel into three fuels, according to the way we regulate its quality: highway diesel fuel, NRLM diesel fuel, and heating oil. Operators of highway diesel engines must use low sulfur highway diesel fuel engines, though the low sulfur fuel can be and is used in other applications. As will be discussed further below, highway diesel fuel must currently meet a 500 ppm sulfur cap. Starting in 2006, 80% of highway diesel fuel volume will have to meet a 15 ppm cap, with 100% having to do so in 2010. NRLM diesel fuel is that fuel used in nonroad, locomotive and marine diesel engines and is the fuel primarily affected by this rule. Heating oil is all other No. 2 distillate fuel. It includes No. 2 fuel oil used in boilers, furnaces and turbines. It also includes No. 2 diesel fuel used in stationary diesel engines (e.g., for electricity generation). Heating oil is not covered by the NRLM fuel standards, but is affected because of limitations in the fuel distribution system.

We base our estimates of historical distillate fuel demand used in this analysis on EPA's Nonroad Model (NONROAD) and the Energy Information Administration's (EIA) Fuel Oil and Kerosene Sales (FOKS) report for 2001. NONROAD estimates diesel fuel consumption by the land-based nonroad engines based on the sales, scrappage and use of nonroad engines. FOKS contains detailed, comprehensive distillate fuel sales to highway vehicles and ten non-highway sectors. We use FOKS to estimate the consumption of highway, marine, and locomotive diesel fuel and heating oil, given the nonroad diesel fuel consumption from NONROAD.

We base future demand for nonroad diesel fuel again on estimates from NONROAD. Future demand for highway diesel fuel and the other non-highway sectors (locomotive, marine and heating oil) is based on estimates from EIA's Annual Energy Outlook (AEO) for 2002.

[C] No. 1 distillate fuels is mostly consumed in jet engines and tends to cost more than No. 2 distillate fuels. Since diesel engines can burn either fuel, No. 2 distillates are their preferred choice.

[D] Some states, particularly those in the Northeast, limit the sulfur content of No. 2 fuel oil to 2000 - 3000 ppm.

The methodology used for the final rule differs somewhat from that used in the NPRM. For the NPRM, we used different methodologies to estimate distillate fuel demand for the purpose of estimating emissions and for estimating fuel-related costs. For emissions, we used a methodology very similar to that being used for this final rule. However, for fuel cost estimation, we did not use NONROAD to estimate nonroad fuel consumption. We derived all of our fuel consumption estimates from FOKS and AEO, although we projected future nonroad fuel consumption with NONROAD. To avoid this inconsistency, we decided to utilize the same methodology for both emission and cost estimation purposes. As discussed in Section 2.3.2.2 of the Summary and Analysis document for this rule, we decided to use NONROAD to estimate nonroad fuel consumption for both emission and cost estimation purposes. In addition, the analysis for this final rule utilizes more recent information from FOKS 2001 and AEO 2002, as opposed to FOKS 2000 and AEO 2001, which were used in the analysis for the NPRM.

We estimate historic production of distillate fuel in these pools by starting with downstream demand. We used Information from EIA's Petroleum Supply Annual on the sales of highway diesel fuel and high sulfur distillate from refinery racks and terminals. The volume of highway diesel fuel supplied at terminals is compared to that consumed in highway vehicles to estimate the percentage of highway fuel which is used in other applications. We call highway fuel used in other applications "spillover." We then adjust the terminal level supply of highway diesel fuel to represent shifts in the volume of various fuels during distribution, particularly through pipelines. These shifts are referred to as "downgrades." The result is an estimate of production needed by refineries and importers to supply demand in the various sectors.

The sulfur level of the various distillate fuels produced at refineries is primarily controlled by applicable EPA standards. These of course vary depending on the regulatory scenario being evaluated. We also consider the impact of the small refiner provisions, which usually allow the sale of higher sulfur fuel into a particular market than would otherwise be the case. The spillover of highway fuel into non-highway sectors also affects the sulfur content of these fuels, as do the downgrades that occur during distribution. Our estimate of in-use sulfur levels of the various distillate fuels begins with in-use survey data and then adjusts these levels for changes in the sulfur content of fuel being produced, spillover and downgrades during distribution.

The two primary regulatory scenarios evaluated are: 1) a reference case, which assumes no NRLM sulfur standards and 2) the final NRLM fuel program. In addition, we evaluate several sensitivity cases:

- NRLM control only to 500 ppm in 2007 (no second step to 15 ppm),

- nonroad fuel control to 15 ppm in 2010, but keeping locomotive and marine (L&M) fuel at 500 ppm indefinitely (the proposal or NPRM case),[E] and

[E] The increment of the final rule program to this regulatory scenario is the basis for our 500 ppm to 15 ppm locomotive and marine incremental analysis.

- the final NPRM fuel program with the volume of nonroad diesel fuel derived from FOKS and AEO 2003 instead of NONROAD.

7.1.2 Distillate Fuel Production and Demand in 2001

This section describes our estimates of total production and demand by region for the various distillate fuels. The primary regions of interest are the different refining districts called PADDs.[F] There are five PADDs: 1) the East Coast, 2) the Midwest, 3) the Gulf Coast, 4) the Mountain states and 5) the West Coast, Alaska and Hawaii. Because the Alaskan and Hawaiian fuel markets are mostly distinct from the rest of PADD 5 and because California applies distinct specifications to diesel fuel sold in that state, we split PADD 5 into four pieces: the states of California, Hawaii and Alaska and the remainder of PADD 5. We will refer to this remainder of PADD 5 as PADD 5-O (with "O" denoting "other" than the specific states listed).

We begin with estimating the demand for each type distillate fuel, highway, NRLM and heating oil. We then estimate how much highway fuel was supplied at the terminal level to estimate spillover of highway fuel into the other sectors. Finally, we estimate downgrade of higher quality fuels to lower quality fuels during distribution to back-calculate the volume of each fuel produced by refineries.

7.1.2.1 2001 Distillate Demand

We obtain our estimate of total distillate demand from EIA's FOKS report for 2001.[1] This report presents results of a national statistical survey of approximately 4,700 fuel suppliers, including refiners and large companies that sell distillate fuels for end use (rather than resale). The sample design involves classification of fuel suppliers based on sales volume with subsamples in individual classes optimized to improve sample precision. Distillate fuels surveyed that are relevant to this analysis include diesel and heating oils in grades No. 1, No. 2 and No. 4. The survey requests respondents to report estimates of fuel sold for eleven "end uses" that correspond to broad economic sectors. These eleven sectors are highway, industrial, off-highway (construction and other), farm, military, railroad, marine vessel, commercial, residential, oil company and electric utility. Suppliers presumably determine the applicable sector by the type of entity which purchases the fuel (e.g., farmers buy fuel for farming). FOKS is therefore not a direct measure of how fuel is used, but a measure of who buys fuel. However, for most of these sectors it should provide a reasonable estimate. The reader is referred to Section 2.3.2.2 of the Summary and Analysis document for this rule for a more detailed description of FOKS and the fuel user surveys which provide an independent assessment of its accuracy.

FOKS presents two sets of fuel demand estimates. The first, labeled unadjusted, includes adjustments to reflect estimates of highway fuel use from the Federal Highway Administration.

[F] The Department of Energy split up the nation into five districts, called Petroleum Allocation for Defense Districts, or PADDs, during the 1970's. The regions primarily reflect where refineries get their crude oil.

The second, labeled adjusted, includes further adjustments to reflect distillate fuel use to generate electricity and to match total distillate demand to total distillate fuel supply, as estimated in EIA's Petroleum Supply Annual (PSA). EIA's PSA reports an aggregation of the volumes of fuels sold by primary suppliers, which includes refinery racks and terminals. As the PSA figures represent recorded sales from all primary suppliers, and not a survey of representative suppliers, it is a more accurate estimate of total distillate fuel supply than the total demand estimated in FOKS. Because of this, we use the adjusted FOKS demand estimates here. Thus, while we refer to total distillate fuel demand as being taken from FOKS, it is just as accurate to say that it comes from PSA.

Of the eleven economic sectors evaluated by FOKS, we are interested primarily in three: highway, railroad and marine vessels. Little fuel used in these sectors involves nonroad equipment or heating oil. The remaining eight sectors all include significant portions of nonroad fuel use and heating oil use. Because of this, we use the EPA NONROAD model to estimate nonroad fuel use and assume that the remainder is heating oil.

Table 7.1.2-1 shows total distillate fuel demand from the 2001 FOKS report, as well as total demand for highway, railroad and marine fuel from this same report.[G] Nonroad diesel fuel demand was taken from the draft NONROAD2004 model (see Chapter 3 for a detailed description of this model). Heating oil demand was set so that the total fuel demand from the five sectors equaled total fuel demand.

Table 7.1.2-1
Total Distillate Demand in 2001 by Region (million gallons)

End Use		Region							
		1	2	3	4	5-O*	AK	HI	CA
Highway		10,284	10,947	5,743	1,570	1,901	111	33	2,627
Railroad		506	1,051	883	223	100	4	0	183
Marine		461	318	1,153	0	23	67	20	52
Other	Nonroad	2,935	4,174	1,409	597	631	25	32	783
	Heating Oil	7,363	602	1,744	78	45	205	129	(41)
Total Demand		21,549	17,092	10,932	2,468	2,700	412	214	3,604

* Represents the states of AZ, NV, OR, and WA.

For this analysis, we made several small modifications to the fuel demand estimates shown in 2001 FOKS. We made one adjustment to the estimate of highway fuel demand. FHWA

[G] Since the volume of No. 4 distillate fuel is small compared to total distillate use, we did not attempt exclude No. 4 distillate use from the 2001 FOKS estimate of total distillate demand. Because of the methodology used, any incremental volume of No. 4 distillate fuel shows up as heating oil demand in Table 7.1.2-1.

estimates highway fuel demand based on fuel excise tax receipts. Individuals and businesses that purchase highway fuel for off-highway use can request a refund of this excise tax on their income tax forms. FHWA adjusts their estimates for these refund requests. However, it is possible that not everyone who uses taxed, highway diesel fuel for non-highway use files for a refund. For example, many businesses own fleets of both highway and nonroad equipment. Some owners or operators, particularly rentals, might find it expedient or necessary to purchase at least some of their nonroad diesel fuel at retail outlets such as gas stations, where high sulfur diesel fuel is usually not available. It is plausible that some fraction of the fuel attributed by FHWA to highway use is actually used for non-highway purposes. This fuel would likely be used by construction and commercial nonroad equipment users, as they are the most likely to refuel their nonroad engines at retail fuel outlets.

To gain a better understanding of this issue, EPA provided a grant to the Northeast States for Coordinated Air Use Management (NESCAUM) to conduct a survey of diesel fuel use in construction equipment in New England.[2] The survey was designed to develop methods to estimate emission inventories for construction equipment. The study area included two counties, one in Massachusetts and one in Pennsylvania. Equipment owners in selected sectors were targeted, including construction, equipment rental, wholesale trade, and government (local highway departments). Surveyors administered a questionnaire requesting information about fuel purchases and associated tax-credits. Owners reported quantities and proportions of high-sulfur (dyed and untaxed) and low-sulfur (undyed and taxed) diesel fuel purchased over the previous year. Owners who reported purchases of undyed diesel fuel for use in construction equipment were also requested to indicate whether they applied for tax credits for which they were eligible under state or federal law. The survey showed that approximately 20 percent of all diesel fuel purchased for use in "construction" was undyed diesel fuel for which the purchaser had not applied for a tax refund.

To ensure that this type of adjustment was not already included in the FOKS estimates, we confirmed with FHWA that they only subtract tax refunds from the total tax receipts from highway diesel fuel sales.[3, 4] In other words, they assume that all purchasers of taxed diesel fuel for non-highway use request a refund. Similarly, we confirmed with EIA that they do not make a similar type of adjustment.[5]

To estimate the volume of nonroad diesel fuel classified as highway fuel demand in FOKS, we applied the results of the NESCAUM survey to the FOKS estimates of construction fuel demand plus a portion of commercial fuel demand. As discussed in Section 7.1.3. below, fuel demand in the commercial sector is broken out by the type of distillate purchased. One of these fuel types is high sulfur diesel fuel, which we believe is primarily used in nonroad equipment. We believe that the results of the NESCAUM are equally applicable to these types of nonroad equipment, as they tend to be used away from the business' primary location (e.g., lawn and garden equipment). However, because the survey only covered two counties, the results are not necessarily representative of the entire U.S. Extrapolating the results to the entire U.S. is therefore uncertain. Given that we lack any other estimate, we decided to use the results of the NESCAUM survey with an ad hoc adjustment, where the percentage of unrefunded highway fuel used is assumed to be 10%, as opposed to the surveyed 20%.

Table 7.1.2-2 shows the volume of construction and commercial, high sulfur diesel fuel, and the portion believed to be made up from unrefunded highway fuel by region. We reduced the total construction volume by 5% to not base our estimates of unrefunded fuel on that portion which is estimated to be used as heating oil (see below). On a nationwide average, this unrefunded highway fuel represents 0.7% of total highway fuel demand. As will be shown below, we reduce the volume of highway fuel demand in each region by the volume shown in Table 7.1.2-2.

Table 7.1.2-2
Unrefunded Use of Taxed Highway Fuel in Nonroad Equipment in 2001 (million gallons)

	Region							
	1	2	3	4	5-O	HI	AK	CA
Total Construction*	550	602	448	124	87	4	7	264
Nonroad Portion (0.95)	523	572	425	118	83	3	7	251
Unrefunded Fuel (10%)	52	57	43	12	8	0.3	0.7	25
Commercial: #2 High Sulfur Diesel Fuel *	203	155	71	8	19	2	21	3
Unrefunded Fuel (10%)	20	16	7	1	2	0.2	2	0.3
Total Unrefunded Fuel	73	73	50	13	10	1	3	25

* FOKS 2001

While we believe that this highway fuel is used in nonroad engines, we did not increase the nonroad fuel demand shown in Table 7.1.1-1 above. This adjustment is not necessary since the NONROAD model projects fuel use for the entire in-use nonroad equipment fleet and does not consider where the fuel is purchased. As will be seen below, the result is that this reduction in highway fuel demand causes an analogous increase in the demand for heating oil under our methodology.

We also made minor adjustments to the FOKS estimates for diesel fuel demand for locomotive engines and marine vessels. Based on guidance from EIA staff, 5% of the fuel purchased by railroads is heating oil, under our definitions described above.[6] Thus, we reduced the railroad fuel demand from FOKS by 5%. We further reduced the railroad fuel demand by an additional 1%, which represents fuel believed to be used in nonroad diesel engines in railyards and which is already included in the nonroad fuel demand estimates from NONROAD.[7] The FOKS estimates of fuel demand for marine vessels were multiplied by 90%, to remove the use of heating oil and No. 4 distillate fuel included in the FOKS estimates. Again, this was based on guidance from EIA staff.[8]

Table 7.1.2-3 shows the FOKS and NONROAD estimates of distillate fuel demand, the adjustments made and the final estimates. Only the revised estimate of heating oil demand is shown, as this is simply back-calculated from the total demand for the other fuels and total distillate demand.

Table 7.1.2-3
Adjusted Distillate Demand by Region in 2001 (million gallons)

End Use	Region							
	1	2	3	4	5-O	AK	HI	CA
FOKS Highway	10,284	10,947	5,743	1,570	1,901	111	33	2,627
Unrefunded fuel (0.7%)	73	73	50	13	10	3	1	25
Revised Highway	10,211	10,873	5,694	1,557	1,890	108	32	2602
FOKS Railroad	506	1,051	883	223	100	4	0	183
Revised Railroad	476	989	831	209	94	4	0	172
FOKS Marine	461	318	1,153	0	23	67	20	52
Revised Marine	415	286	1,037	0	20	60	18	46
Nonroad	2,935	4,174	1,409	597	631	25	32	783
Heating Oil	7,511	769	1,961	105	64	214	132	0
Total	21,549	17,092	10,932	2,468	2,700	412	214	3,604

7.1.2.2 2001 Distillate Fuel Production

Refiners do not produce exactly the same volume of fuel which is consumed. This is especially true for the specific categories of distillate fuel. The largest difference occurs with highway diesel fuel. All fuel used in highway diesel engines must meet EPA's 500 ppm sulfur cap. Other distillate fuel does not. However, fuel meeting the highway diesel fuel specification can be used in the other four categories. As is shown below, this occurs to a significant extent. We refer to this as spillover. Thus, the production of highway diesel fuel tends to be much larger than is actually consumed in highway diesel engines. More importantly for this rule, the highway fuel used in NRLM engines already meets the sulfur caps of the final NRLM fuel program. Thus, this spillover fuel faces no new production or distribution costs due to this rule.

Also, a certain amount of mixing occurs when fuel is shipped in pipelines, particularly at the interface between fuel batches. The properties of this interface material are a blend of the properties of the two distinct fuel batches. Generally, this interface material does not meet the specification of one of the two fuels and is cut into the batch of the lower quality fuel. We refer to the volume of the higher quality fuel that is lost to the lower quality fuel as downgrade. However, sometimes this interface does not meet the specifications of either fuel and has to be segregated from both batches and reprocessed. This downgraded material is referred to as transmix.

Downgrade can both increase and decrease the supply of distillate fuel relative to that which was produced by refineries. We consider these changes in the supply various distillate fuels below when estimating the cost of providing NRLM fuel meeting the final NRLM sulfur standards.

Spillover

Spillover is the volume of highway diesel fuel supplied which exceeds highway diesel fuel demand and is thus used by off-highway users. We estimate spillover volume by subtracting diesel fuel consumption by highway vehicles from the total supply of low-sulfur, highway fuel. We already estimated highway fuel consumption by highway engines (see Table 7.1.2-3 above). We obtain highway fuel supply to each region from EIA's Petroleum Marketing Annual 2001.[9] It should be noted that PMA estimates distillate fuel supply from primary suppliers, which are primarily refinery racks and terminals. Thus, any downgrades occurring in pipelines have already occurred. However, fuel sales by transmix processors are included in PMA. Thus, any distillate fuel recovered from transmix processing is also included in PMA. Table 7.1.2-4 shows the spillover volumes in each region based on the above information.

Table 7.1.2-4
Highway Fuel Spillover in 2001 (million gallons)

	1	2	3	4	5-O	AK	HI	CA	U.S.
Total Supply	10,596	12,549	6,532	2,067	2,206	111	45	3,568	37,674
Highway Engine Demand	10,211	10,873	5,694	1,557	1,890	108	32	2,602	32,967
Spillover	385	1,676	838	510	316	3	13	966	4,707

Information on the use of this spillover of highway fuel in the individual nonroad, locomotive, marine, and heating oil markets does not exist. Therefore, we assume that this spillover represents the same percentage of total demand for each fuel category within a region. Table 7.1.2-5 shows spillover, total non-highway distillate demand, and the percentage of spillover to non-highway distillate demand by region.

Table 7.1.2-5
Spillover As Percentage of the Non-Highway Distillate Demand, 2001 (million gallons)

	1	2	3	4	5-O	AK	HI	CA
Spillover	385	1,676	838	510	316	3	13	9
Non-Highway Distillate Demand	11,337	6,218	5,238	911	809	303	182	1,001
Spillover (% of Non-Highway Demand)	3.4	26.9	16.0	55.9	38.9	1.0	7.1	100

As can be seen, the degree of spillover varies widely across the U.S. Spillover is very low in Alaska and Hawaii, because of the absence of fuel product pipelines. Spillover is also very low in

PADD 1, because of its large demand for high sulfur heating oil. This large demand causes high sulfur distillate to be available nearly everywhere, particularly in the northern portion of PADD 1. Thus, there is little reason for highway fuel to be used in non-highway applications. Spillover is relatively high in PADD 4 due to the fact that several pipelines in the region do not carry high sulfur distillate. Finally, spillover is very high in California, as that State requires the use of 500 ppm fuel in nonroad engines.

The final issue is the distribution of this spillover into the four high sulfur distillate markets: nonroad, locomotive, marine, and heating oil. Differences do exist in the way that these fuels are typically shipped, particularly for locomotive and marine fuel. This could affect the relative volume of spillover added to that market. However, data are not available which indicate any difference in the distribution of spillover. Thus, except for the unrefunded use of highway fuel in the construction and commercial sectors, we assume that the spillover is distributed into the four high sulfur distillate markets in proportion to their total demand. Consistent with the way the NESCAUM survey was conducted, we assume that the portion of spillover coming from unrefunded use of highway fuel is all nonroad fuel demand.

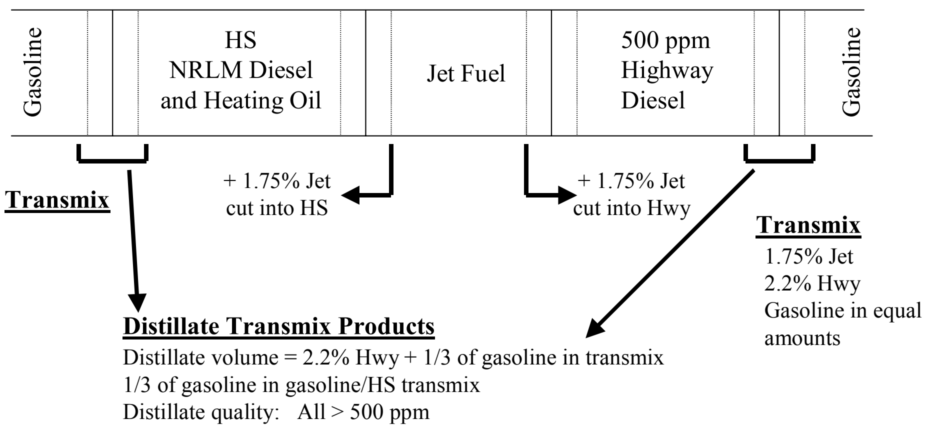
Downgrade

When fuel is shipped through pipelines, the batch of one fuel flows immediately next to a batch of another fuel. As the fuel flows through the pipeline, the two fuels start to mix at the interface of the two batches. This interface takes on a character of its own and its properties are a blend of the properties of the two fuels. The mixture is commonly called interface material or simply interface. Depending on the properties of the two fuels and the stringency of the specifications what each fuel must meet, this interface material can simply be cut in half and blended into the two batches of fuel. In this case, there is no loss of volume in either batch. However, usually one of the two fuels is of higher quality than the other and the interface is blended into the lower quality batch. In this case, the lower quality fuel gains volume, while the higher quality fuel loses volume. This loss of volume is called downgrade.

The loss of higher quality fuel volume through downgrade means that more of this fuel must be produced than implied by demand. Likewise, the gain of lower quality fuel volume through downgrade means that less of this fuel must be produced than implied by demand. The latter is particularly important after the control of NRLM fuel sulfur content, as heating oil demand (a sink for high sulfur downgrade) in some of the regions is quite limited. Also, the sulfur content of downgrade will differ from that of fuels produced at refineries. Thus, the relative volume of downgrade being sold in each fuel market will affect the average in-use sulfur content of that fuel and the emission reductions resulting from this NRLM rule.

Figure 7.1-1 shows the order in which petroleum fuels are typically shipped through pipelines today.[10] Jet fuel is often "wrapped" with high sulfur distillate and highway diesel fuel. The sides of the batches of high sulfur distillate and highway diesel fuel not adjacent to jet fuel are often adjacent to gasoline of some type. The order of fuels can vary from pipeline to pipeline. However, the specific order will generally not affect the volumes and quality of downgrade estimated here. According to our methodology, the size of the various interfaces are generally independent of the adjacent fuels and any distillate fuel lost to transmix is recovered by transmix processors. The only difference might be the percentage of downgraded distillate which is able to be sold to the 500 ppm highway fuel market versus the high sulfur distillate market. While this breakdown affects current fuel supply, it is not an issue once diesel fuel must meet a 15 ppm cap.

Figure 7.1-1 Pipeline Sequence and Fate of the Interface Between Fuel Pipeline Batches in 2001



At the interface between these different fuels there is a mixing zone which results in the two fuels contaminating each other. There are two different ways this mixed fuel between the two fuels is dealt with by the pipeline companies. One way that pipeline companies deal with the interface between the two fuels is to simply downgrade the mixture into the batch of fuel with the lowest quality. Pipeline companies have informed us that the entire interface zone between jet fuel and highway diesel fuel and also the interface zone between jet fuel and high sulfur distillate is simply "cut" into the batches of highway diesel fuel and high sulfur distillate, respectively, by timing their valve actions. This can occur because jet fuel would generally comply with the specifications of the other two pools.[H]

The second way to handle this interface occurs when the specifications governing the quality of each fuel prevents the interface from being blended into either fuel. This always occurs between a batch of gasoline and a batch of any distillate fuel. Even a small amount of gasoline would cause diesel fuel to exceed its flashpoint limit. Similarly, a small amount of diesel fuel would cause gasoline to exceed its endpoint limits. In this case, the interface is commonly referred to as transmix. Transmix must be separated from either batch, is usually stored in a transmix tank with other types of transmix, and then shipped to a transmix processor. The

[H] The sulfur content of jet fuel often exceeds 500 ppm. However, adding a small volume jet fuel to highway diesel fuel usually will not cause the sulfur content of the highway diesel fuel to exceed 500 ppm.

physical characteristics of pipeline mixing indicate that the interface would generally contain roughly even quantities of gasoline and distillate. We assume that this is the case here.

The transmix processor distills the transmix to produce a reprocessed gasoline and distillate fuel. However, there is some overlap between the lower temperature boiling components of distillate, particularly jet fuel and the higher temperature boiling components of gasoline. The lower temperature boiling components of distillate have a particularly low octane number. If any significant quantity of distillate is mixed with the gasoline product, the cost of raising the octane number to back to 87 or higher is economically prohibitive. Therefore, transmix processors operate their distillation columns so that roughly one-third of the original gasoline contained in the transmix leaves with distillate product.

We are not concerned with the gasoline produced by transmix processors here. However, the gasoline portion of the original transmix which enters the distillate pool in this fashion affects both the volume and sulfur content of the distillate fuel pool and is, thus, relevant to this discussion.

The distillate portion of current transmix can consist of highway diesel fuel, jet fuel and high sulfur distillate, plus the heaviest components of gasoline. Because most pipelines carry high sulfur distillate fuel currently and jet fuel often exceeds 500 ppm sulfur, and because most facilities have only one tank for storing transmix from all interfaces, we assume that the distillate produced from transmix is usually sold as high sulfur distillate. Thus, per Figure 7.1-1, the highway diesel fuel portion of transmix is shifted to high sulfur distillate supply.

The next step in our assessment of downgrade is to estimate its volume. The jet fuel downgrade is easiest to estimate because, assuming the shipping order shown in Figure 7.1-1, it is simply cut into each adjacent pool. We polled several pipeline companies to obtain an estimate on the quantity of jet fuel downgraded today. Their estimates of the volume of jet fuel downgraded during distribution ranged from 1% to 7%.[11] We assumed that the national average downgrade percentage was near the mid-point of this range, or 3.5%. Per Figure 7.1-1, half of this volume is shifted to the highway fuel market and half is shifted to the high sulfur distillate market. Table 7.1.2-6 shows this shift.

Table 7.1.2-6
Types of Downgrade and Their Volumes in 2001

Interface	Original Fuel	Destination	Volume
Jet Fuel Interface	Jet Fuel	Highway Diesel Fuel	1.75% of jet fuel demand
		High Sulfur Distillate	1.75% of jet fuel demand
Gasoline - High Sulfur Distillate Interface	High Sulfur Distillate	High Sulfur Distillate	Neutral
	Gasoline	High Sulfur Distillate	Equivalent to 0.58% of jet fuel demand
Gasoline - Highway Diesel Fuel Interface	Highway Diesel	High Sulfur Distillate	2.2% of highway diesel fuel supply
	Gasoline	High Sulfur Distillate	Equivalent to 0.73% of highway diesel fuel supply

The other downgrades occur through the creation of transmix and its processing. Starting with high sulfur distillate fuel, some of the volume of this fuel is lost to transmix. However, transmix processors return all of the distillate portion of the original transmix to their distillate product. As stated above, we assume that all the distillate produced by transmix processors contains more than 500 ppm sulfur and is sold to the high sulfur distillate market. Thus, the volume of high sulfur distillate which is lost to transmix is eventually returned to the high sulfur distillate market by transmix processors. The result is no net loss or gain in the high sulfur distillate market through its mixture with gasoline. This is shown in Table 7.1.2-6.

While the high sulfur distillate portion of this transmix returns to the fuel pool from which it came, the gasoline which abuts high sulfur distillate in the pipeline does not all return to gasoline supply. The heaviest portion of this gasoline moves from the gasoline market to the high sulfur distillate market. We were not able to obtain a direct estimate of the volume of gasoline lost in this manner or the volume of high sulfur distillate shifted to transmix. Thus, we estimate this volume by comparing it to the volume of jet fuel moved to the high sulfur distillate pool. As mentioned above, the mixing properties of all these fuels are fairly similar. They also have flowed through the pipeline over the same distance (i.e., all these fuels are major products which tend to flow the entire length of the pipeline). Thus, it is reasonable to assume that the interface on either side of the batch of high sulfur distillate has the same volume. If 1.75% of jet fuel is lost to high sulfur distillate on one side of the batch, then the same volume of high sulfur distillate will be lost to transmix on the other side of the batch. Likewise, the same volume of gasoline will be lost to this transmix through the interface with high sulfur distillate. The percentages of gasoline and high sulfur distillate lost will not be the same as the size of the jet fuel, gasoline and high sulfur distillate batches will likely differ, since their total demands vary widely. However, the absolute volumes of jet fuel, gasoline and high sulfur distillate contributing to the interfaces should be very similar.

As mentioned above, two-thirds of the gasoline portion of transmix leaves the transmix processor as naphtha and returns to the gasoline pool. However, the other one-third leaves as distillate. As mentioned above, we assume that it does so as high sulfur distillate today. Thus, a volume of gasoline equivalent to one-third of 1.75% of jet fuel demand (or 0.58% of jet fuel demand) is shifted from gasoline to the high sulfur distillate fuel market. This is shown in Table 7.1.2-6.

This leaves the downgrade of highway diesel fuel. In the Final RIA for the 2007 highway diesel rule, we estimated that a clean cut on one side of highway diesel fuel batches would downgrade 2.2% of the supply of highway diesel fuel.[1] We have applied this estimate in this analysis, as well. In Figure 7.1-1, this 2.2% loss occurs via the creation of transmix with gasoline. We assume that the volume of gasoline contributing to this transmix is the same, 2.2% of highway diesel fuel supply. All of the highway diesel fuel leaves the transmix processor as high sulfur distillate. One-third of the gasoline (equivalent to 0.73% of highway diesel fuel supply) does so, as well. These downgrades are shown in Table 7.1.2-6.

The volumes of the various types of downgrade shown in Table 7.1.2-6 fall into two groups. The first are a function of jet fuel demand, while the second are a function of highway diesel fuel supply. To simplify our calculations, we aggregated the volumes of these two types of downgrades to create just two categories of downgrades, jet-based downgrade and highway fuel-based downgrade. Jet-based downgrade consists of the jet fuel lost to both the highway and high sulfur distillate fuel supplies. It also includes the gasoline lost to the high sulfur distillate pool via interface with high sulfur distillate fuel in the pipeline. In total, the jet-based downgrade represents 4.08% of jet fuel demand. Of this 4.08%, 1.75% shifts to highway diesel fuel supply, while 2.33% shifts to high sulfur distillate supply. Highway fuel-based downgrade consists of the highway diesel fuel and gasoline which is shifted to high sulfur distillate supply via the interface between highway diesel fuel and gasoline in the pipeline. This downgrade consists of 2.93% of highway diesel fuel supply.

The relative volumes of jet fuel demand and highway diesel fuel supply vary across the various regions of the country being evaluated here. Thus, the relative volumes of the two types of downgrade will vary, as well. Table 7.1.2-7 shows the demand for jet fuel and highway diesel fuel, the volume of each type of downgrade and the portions of these downgrades shifted to highway and high sulfur distillate fuel. Since the States of Alaska and Hawaii have no product pipelines, we assumed no downgrade occurs there.

[1] When highway diesel fuel must meet a 15 ppm cap standard starting in 2006, we project that the amount of downgrade will increase to protect the cleaner highway diesel fuel. We discuss this in the next section.

Table 7.1.2-7
Downgrade Generation and Disposition in 2001 (Million gallons)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
Jet-Based Downgrade								
Jet Fuel Demand (PMA)	4,585	3,776	6,095	562	1,580	1,014	325	3,772
Downgrade Loss	187	154	249	23	64	0	0	154
To Highway Fuel	80	66	107	10	28	0	0	66
To High Sulfur Fuel	107	88	142	13	37	0	0	88
Highway Fuel Based Downgrade								
Highway Fuel Supply	10,596	12,549	6,532	2,067	2,206	111	45	3,568
Downgrade Loss	310	368	191	61	65	0	0	105
Net Highway Fuel Loss*	233	276	144	45	49	0	0	78
High Sulfur Fuel Gain	310	368	191	61	65	0	0	105

* The difference is due to downgrade from gasoline.

The final issue is how the new supply of high sulfur distillate is apportioned among the four uses of high sulfur distillate fuel: nonroad, locomotive, marine, and heating oil. Data are not available which indicate any difference in the final disposition of high sulfur distillate fuel produced from transmix compared to that produced by refineries. Thus, we assume that the spillover is equally distributed into the four non-highway distillate markets in proportion to their demand.

Production

Distillate fuel production must be sufficient to supply demand, considering changes in supply during distribution. Since the net loss in highway fuel produced is 2.2%, highway fuel production must be 2.2% higher than that indicated in EIA's PMA for 2001. Likewise, the production of high sulfur distillate fuel is lower than the estimate of supply from PMA, due to the addition of some gasoline, jet fuel and highway diesel fuel. The balance of production, gains and losses during distribution and final supply are shown in Table 7.1.2-8.

Table 7.1.2-8
Distillate Production and Demand in 2001 (million gallons)

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 500 ppm	10,840	12,847	6,622	2,115	2,227	111	45	34,806	3,468	38,275
	Spillover to Non-hwy	-383	-1,656	-831	-504	-312	-3	-13	-3,701	-830	-4,532
	Hwy Downgrade	-327	-387	-202	-64	-68	0	0	-1,048	-95	-1,143
	Jet Downgrade	81	69	105	10	43	0	0	309	59	368
	Demand	10,211	10,873	5,694	1,557	1,890	108	32	30,366	2,602	32,968
Non-road	Production HS	2,672	2,725	1,064	215	289	22	29	7,016	0	7,015
	Hwy Spillover	151	1,130	255	332	245	3	3	2,118	675	2,787
	Jet Downgrade	28	61	38	9	45	0	0	181	61	242
	Hwy Downgrade	83	258	53	41	53	0	0	489	72	561
	Demand	2,935	4,174	1,409	597	631	25	32	9,803	783	10,586
Loco-motive	Production HS	445	658	651	77	44	4	0	1,878	0	1,879
	Hwy Spillover	13	255	125	114	36	0	0	543	142	685
	Jet Downgrade	5	15	22	3	7	0	0	51	14	65
	Hwy Downgrade	14	62	32	15	8	0	0	131	17	148
	Demand	476	989	831	209	94	4	0	2,604	172	2,776
Marine	Production HS	388	190	813	0	9	60	17	1,478	0	1,477
	Hwy Spillover	11	74	156	0	8	0	1	250	38	288
	Jet Downgrade	43	4	28	0	1	0	0	37	4	41
	Hwy Downgrade	12	18	40	0	2	0	0	72	4	77
	Demand	415	286	1,037	0	20	60	18	1,838	46	1,884
Heating Oil	Production HS	7,014	511	1,537	39	30	214	123	9,469	0	9,469
	Hwy Spillover	207	198	295	57	24	0	9	791	0	791
	Jet Downgrade	72	11	52	2	5	0	0	142	0	142
	Hwy Downgrade	218	48	76	7	5	0	0	356	0	356
	Demand	7,511	769	1,961	105	64	214	132	10,757	0	10,757

7.1.3 Distillate Fuel Production and Demand in 2014

As described in Section 7.2.1, we estimate the cost per gallon of desulfurizating NRLM fuel using refinery specific production volumes indicative of 2014. This is the mid-point of the useful life of hydrotreating equipment built in 2007, per IRS depreciation guidelines. Thus, using production volumes from 2014 provides a reasonable estimate of the economies of scale of hydrotreating expected to exist over the life of new equipment built in response to this rule.[J] As was the case for 2001, we begin with estimating future demand, and then estimate the fuel production necessary to satisfy this demand considering spillover and downgrades.

[J] In Chapter 8, we project the cost of replacing the hydrotreaters built in 2007. In doing so, we did not increase the estimated refinery-specific production volumes to represent growth in NRLM fuel demand beyond 2022 (2007 plus the 15 year life of the equipment). This overestimates the cost of replacement equipment to a small extent.

7.1.3.1 Distillate Fuel Demand in 2014

We derive our estimates of growth in highway, locomotive and marine fuel demand from 2001 to 2014 from EIA's AEO for 2003.[12] Table 7.1.3-1 shows the projected growth in demand for these three fuels, as well as projected growth for jet fuel demand. The fuel demand in each of these three categories in 2001 (shown in Table 7.1.2-8) were multiplied by the respective growth factors to estimate fuel demand in 2014. This implicitly assumes that the same growth rate applies in each region.

Table 7.1.3-1
Projected Growth in Highway, Locomotive and Marine Fuel Demand: EIA 2003 AEO

	Highway	Locomotive	Marine	Jet Fuel
Demand in 2001 (trillion BTU)	5440	630	340	3960
Demand in 2014 (trillion BTU)	7840	710	390	2970
Growth Factor to 2014	1.44	1.13	1.14	1.34

Nonroad fuel demand in 2014 was estimated using the draft NONROAD2004 model, as was done for 2001. Nonroad fuel demand in 2014 is estimated to be 14,379 million gallons per year, which represents a 36% increase over 2001.

We projected the growth in heating oil demand from information contained in the 2003 AEO 2003, along with our own estimates of the heating oil portion of each of the economic sectors tracked in AEO. In its 2003 AEO, EIA projects the demand of petroleum fuels from 2001-2025 based on historical demand and econometric and engineering forecasts. AEO does not provide forecasts for heating oil demand as we define it here. Thus, we estimate the heating oil portion of the fuel demand in each economic sectors tracked in AEO. We then weighted the growth in the fuel demand in each of the economic sectors by its contribution to total heating oil demand in 2001. Table 7.1.3.2 shows distillate fuel demand in each of the economic sectors tracked by AEO. (Highway fuel use is not shown, since there is no heating oil use in this category.) The estimates of demand were taken from the 2001 FOKS report. FOKS breaks down fuel use by fuel type for several of the sectors. We believe that the use of distillate fuel varies depending on the type of fuel being consumed (e.g., low sulfur diesel fuel, high sulfur diesel fuel, high sulfur fuel oil) The FOKS breakdown allows us to apply distinct heating oil percentages to each sector and fuel type combination. The information presented in Table 7.1.3-2 describes the process we used to estimate the source of heating oil demand in 2001.

Table 7.1.3-2
Source of Heating Oil Demand: 2001

End Use	Fuel Grade	Distillate Fuel		Heating Oil	
		FOKS Volume (1000 gal)	Percent Heating Oil	Volume (1000 gal)	Percent Heating Oil Pool
Farm	diesel	3,351	0	0	0
	distillate	77	100	77	0.7
Construction	distillate	2,086	5	104	0.9
Other/(Logging)	distillate	428	5	21	0.2
Industrial	No. 2 fuel oil	354	100	354	3.2
	No. 4 distillate	44	100	44	0.4
	No. 1 distillate	44	60	26	0.2
	No. 2 low-S diesel	849	0	0	0
	No. 2 high-S diesel	1,033	0	0	0
Commercial	No. 2 fuel oil	1,546	100	1,546	14.1
	No. 4 distillate	200	100	200	1.8
	No. 1 distillate	63	80	50	0.5
	No. 2 low-S diesel	1,212	0	0	0
	No. 2 high-S diesel	483	0	0	0
Oil Company	distillate	820	50	410	3.7
Military	diesel	310	0	0	0
	distillate	36	100	36	0.4
Electric Utility	distillate	1,510	0	1,510	13.8
Railroad	distillate	2,952	5	148	1.3
Vessel Bunkering	distillate	2,093	10	209	1.9
On-Highway	diesel	33,130	0	0	0
Residential	No. 2 fuel oil	6,151	100	6,151	55.9
	No. 1 distillate	112	100	112	1.0
Total		58,971		10,998	100

The key figures in Table 7.1.3-2 are the percentages of each economic sector and fuel type combination which we believe falls into our definition of heating oil. These percentages were derived using the same methodology which we use in Section 7.1.4 below to derive an estimate of nonroad fuel demand from FOKS fuel demand estimates. The difference here is that we are not focused on nonroad fuel demand, but on heating oil demand. In most of the economic sectors shown in Table 7.1.3-2, if the fuel is not nonroad fuel, it is heating oil. The exceptions to this are: 1) locomotive and marine vessel fuel, where the fuel that is not heating oil is locomotive or marine fuel, respectively, and low sulfur diesel commercial fuel, which is highway fuel which is not subject to highway fuel excise taxes (e.g., school buses).

As shown in Table 7.1.3-2, we multiply the total fuel demand for that specific economic sector and fuel type by its heating oil percentage to estimate the volume of heating oil demanded in that sector-fuel type combination. We then divide that heating oil demand by total heating oil demand to derive the percentage of total heating oil demand represented by that sector-fuel type combination. The information presented in Table 7.1.3-3 describes the next step in this process. Table 7.1.3-3 shows the total distillate fuel demand in 2001 and 2014 from 2003 AEO and the ratio of these fuel demand volumes.

Table 7.1.3-3
Projected Growth in Heating Oil Demand: 2001 to 2014

Category	2001 Distillate Demand *	2014 Distillate Demand *	Ratio of 2014 to 2001 Distillate Demand	Percent of Total Heating Oil Demand
Farm	469	533	1.14	0.7
Construction	238	274	1.15	0.9
Logging/Other	55.6	59.9	1.08	0.2
Industrial	1,130	1,270	1.12	3.8
Commercial	460	490	1.07	16.4
Oil Company	6.2	0	0	3.7
Military	101	124	1.22	0.4
Electric Utility	170	90	0.70	13.8
Railroad	628	707	1.13	1.3
Vessel Bunkering	345	394	1.14	1.9
Residential	910	880	0.97	56.9
Weighted Ave.	-	-	0.93	

* Trillion BTU from the 2003 AEO.

We weighted the growth in each sector's distillate fuel demand by that sectors' contribution to 2001 heating oil demand. For farm, industrial, commercial, residential and military, the contributions of the various fuel types shown in Table 7.1.3-2 were combined for use in Table 7.1.3-3. The result is that heating oil demand is projected to shrink by 7% between 2001 and 2014. Thus, we multiplied the heating oil demand in each region shown in Table 7.1.2-8 by 0.93 to estimate heating oil demand in 2014. Table 7.1.3-4 shows the resulting distillate demands projected for 2014 for the five fuel categories. Table 7.1.3-4 also shows jet fuel demand in 2014, which represents a 34% increase over those shown in Table 7.1.2-7.

Table 7.1.3-4
Distillate Demand in 2014 (million gallons)

End Use	Region								
	1	2	3	4	5-O	AK	HI	CA	U.S.
Highway	14,722	15,676	8,210	2,245	2,725	157	46	3,752	47,533
Nonroad	3,987	5,670	1,914	810	857	34	43	1,064	14,379
Railroad	536	1,114	935	236	106	5	0	194	3,126
Marine	475	327	1,187	0	23	69	21	53	2,155
Heating Oil	6,970	714	1,820	98	59	199	122	0	9,982
Total No. 2 Distillate Demand	26,690	23,501	14,066	3,389	3,770	464	232	5,063	77,175
Jet Fuel	6,143	5,060	9,313	753	2,117	1,359	436	5,054	30,235

7.1.3.2 Future Distillate Fuel Production

The primary purpose of projecting production of the various types of distillate fuel in 2014 is to factor in appropriate economies of scale for the investment in new desulfurization equipment to comply with the NRLM sulfur standards. We use 2014 production volumes to estimate these costs for all of the steps of the final NRLM fuel program, because 2014 represents the mid-point of the life of refinery equipment for the purposes of calculating annual depreciation under IRS guidelines. The five steps for which production volumes were estimated are:

1) Reference Case (i.e., no NRLM Program),
2) Final NRLM fuel Program: 2007-2010,
3) Final NRLM fuel Program: 2010-2012,
4) Final NRLM fuel Program: 2012-2014, and
5) Final NRLM fuel Program: 2014 and beyond

7.1.3.2.1 Reference Case; no NRLM Fuel Program

There are two distinct periods which define the reference case which assumes that the NRLM fuel program was not promulgated. One is during the period between 2007 and 2010 when the highway diesel fuel program's temporary compliance option is in effect. During this time, consistent with the refiners' pre-compliance reports under the highway fuel program, we assume 5% of highway diesel fuel will be produced at 500 ppm.[13] The remainder will be 15 ppm fuel. The second period is after 2010 when the highway diesel fuel program's temporary compliance option expires and all highway diesel fuel must meet a 15 ppm cap. During both of these periods, NRLM fuel would continue to be high sulfur diesel fuel.

California has implemented its own sulfur standards for highway and nonroad diesel fuel pool starting in 2006. Thus, nonroad diesel fuel in California was assumed to already meet the 15 ppm standard in the reference case. While California will not be regulating the locomotive and marine diesel fuel quality as part of its regulation, our analysis shows that the locomotive and marine diesel fuel demand will be met using spillover and the low sulfur diesel fuel downgrade once the nonroad pool is regulated to 15 ppm. Therefore, EPA's NRLM program is not expected to have any impact on the production or distribution of locomotive and marine diesel fuel in that State.[K]

We project the production volume of highway diesel fuel in 2014 using a slightly different methodology than we used for 2001 production. For 2001, we started with supply and demand and calculated spillover. Downgraded volume was then added to estimate total production. For 2014, we start with highway fuel demand, add the spillover of highway fuel into non-highway fuel markets based on 2001 estimates, and add the volume of highway fuel which is downgraded to lower quality fuel.

The demand for highway diesel fuel was estimated in the previous section. Regarding spillover, we assume that the same constraints in the distribution system which cause most spillover to occur today will continue in the future. This means that the volume of highway fuel spilling over into each of the four non-highway fuel markets will grow as each of these markets grows. Thus, we have increased the spillover volumes shown in Table 7.1.2-5 for the nonroad, locomotive, marine and heating oil markets by the 2001 to 2014 growth factors for these fuels shown in Tables 7.1.3-1 and 7.1.3-3 (and a factor of 1.36 for nonroad fuel). The net effect of this assumption is that the percentage of demand represented by spillover in each of the four non-highway fuel markets is the same in 2014 as in 2001. Table 7.1.3-5 shows the demand for highway fuel, spillover into each of the four non-highway fuel markets, and the resultant supply of highway fuel needed to provide for this demand and spillover.

[K] Our conclusion that California will not be affected by the NRLM program is based on our nationwide analysis on how fuels are produced and distributed throughout the U.S. focusing on areas outside of California. It is possible that California fuel production and distribution is different enough that some fuel would in fact be affected by this rulemaking.

Table 7.1.3-5
Spillover of Highway Fuel in 2014 (million gallons)

End Use	Region							
	1	2	3	4	5-O	AK	HI	CA
Highway Demand	14,722	15,676	8,210	2,245	2,725	157	46	3,752
Spillover								
Nonroad	206	1,535	345	451	333	4	4	1,054
Railroad	15	287	141	129	40	0	0	0
Marine	13	84	179	0	9	0	1	0
Heating Oil	192	184	274	53	22	0	8	0
Total Spillover	425	2,090	939	633	404	4	13	1,298
Highway Supply	15,247	17,911	9,127	2,900	3,111	161	60	4,978

As mentioned above, the State of California has promulgated regulations requiring that nonroad fuel meet a 15 ppm cap, as well as highway fuel, in 2006. We have categorized this 15 ppm nonroad fuel as highway fuel to better distinguish between 15 ppm fuel which would be produced prior to this NRLM rule and that which will be produced because of this rule. Because 15 ppm nonroad fuel in California will be produced with or without this rule, we have classified it as highway fuel in our presentation. Thus, any production of 15 ppm nonroad fuel shown below will be due to this rule and not due to California regulations.

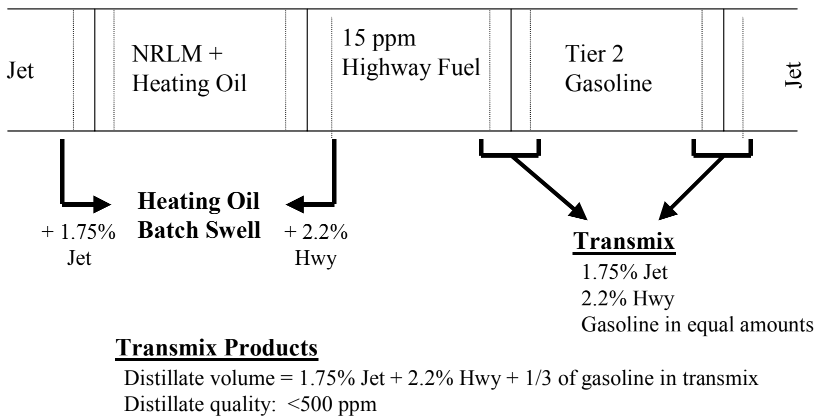
The next step is to estimate the volume of downgrade into and out of the various fuel supply pools, as was done for 2001. In the Final RIA for the 2007 highway diesel rule, we projected that the downgrade of 15 ppm highway diesel fuel would increase to 4.4% from the current estimated level of 2.2%. Thus, we assume that 4.4%[L] of the supply of highway fuel shown in Table 7.1.3-5 will be downgraded to a lower quality distillate.

The implementation of the 15 ppm highway fuel cap in 2006 could affect sequencing in some pipelines. Most pipelines will simply replace their 500 ppm highway fuel with 15 ppm highway fuel. However, some pipelines will continue to carry a 500 ppm highway fuel through mid-2010. In the Final RIA of the highway rule, we projected that roughly 40% of fuel markets would include a 500 ppm fuel to distribute the roughly 20% of highway fuel which would be at 500 ppm. However, the highway pre-compliance reports indicate a much lower percentage of highway fuel which likely be produced at 500 ppm. Because of this and for simplicity, we assume that most pipelines would not carry 500 ppm highway fuel absent the NRLM rule. However, we believe that the sequencing of fuels in pipelines will still likely change from that

[L] Due to a miscalculation, the highway diesel fuel downgrade is estimated to be 4.5% instead of 4.4% for all analyses after 2010. The overestimated highway downgrade volume overestimates the costs of the program.

shown in Figure 7.1.1. In particular, we believe that pipelines would not wrap 15 ppm highway fuel with jet fuel and heating oil, but would wrap it with heating oil and gasoline, as shown in Figure 7.1-2. With the sequence shown in Figure 7.1-1, the interface between jet fuel and 15 ppm highway fuel could not be cut into either fuel, but would have to be segregated and added to the heating oil storage tank. With the sequence in Figure 7.1-2, all of the distillate-distillate interfaces can be cut into heating oil and the only interfaces requiring segregation and processing are those containing gasoline and distillate, as is currently the case.

Figure 7.1-2 Pipeline Sequence and Fate of Interface Between Fuel Batches in Areas that Carry Heating Oil; Prior to NRLM Rule: 2006+



The change in sequencing affects the types of downgrade which will occur. Table 7.1.3-6 shows these downgrades and their volumes. Overall 3.5% of jet fuel volume is still downgraded to the distillate market. In addition, gasoline volume equivalent to 0.58% of jet fuel demand and 0.73% of highway fuel supply will also be downgraded to the distillate market. The volume of high sulfur distillate supplied should again not be affected. Only the volume of highway fuel downgraded will increase, from 2.2% to 4.4% of total supply. We assume that the jet fuel and highway diesel fuel interfaces with high sulfur distillate will be cut directly into the batch of high sulfur distillate. Therefore, half of the jet fuel downgrade and half of the highway diesel fuel downgrade will be cut directly into batches of high sulfur distillate. The remaining downgrades are mixed with gasoline and sent to transmix processors, where distillate fuel is recovered and sold. Due to the Tier 2 sulfur standards applicable to gasoline in 2004 and beyond and the 15 ppm highway diesel fuel cap, the sulfur content of distillate produced by transmix processors will decrease dramatically. As described in Section 7.7 below, we estimate that the sulfur content of distillate produced by transmix processors will be well below 500 ppm. The 500 ppm highway diesel fuel market should command a price premium over high sulfur distillate fuel during this timeframe. Therefore, we assume that this distillate will be sold to the 500 ppm highway diesel fuel market.

Table 7.1.3-6
Types of Downgrade and Their Volumes for the Reference Case: 2006-2010

Interface	Original Fuel	Destination	Volume
Jet Fuel- High Sulfur Distillate Interface	High Sulfur Distillate	High Sulfur Distillate	Zero
	Jet Fuel	High Sulfur Distillate	1.75% of jet fuel demand
Gasoline - Jet Fuel Interface	Jet Fuel	500 ppm Highway Fuel	1.75% of jet fuel demand
	Gasoline	500 ppm Highway Fuel	Equivalent to 0.58% of jet fuel demand
Highway Diesel Fuel- High Sulfur Distillate Interface	High Sulfur Distillate	High Sulfur Distillate	Zero
	Highway Diesel Fuel	High Sulfur Distillate	2.2% of highway diesel fuel supply
Gasoline - Highway Diesel Fuel Interface	Highway Diesel	500 ppm Highway Fuel	2.2% of highway diesel fuel supply
	Gasoline	500 ppm Highway Fuel	Equivalent to 0.73% of highway diesel fuel supply

We obtained future demand for jet fuel from 2003 AEO. There, EIA projects a 34% increase in jet fuel demand compared to demand in 2001. We applied this nationwide increase to the 2001 jet fuel demand by region shown in Table 7.1.2-7. The resultant 2014 jet fuel demand by region is summarized in Table 7.1.3-7.

Table 7.1.3-7
Downgrade Generation and Disposition for the Reference Case: 2006-2010 (Million gallons)

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
Jet-Based Downgrade								
Jet Fuel Demand (PMA)	6,144	5,060	8,167	753	2,117	1,359	435	5,054
To High Sulfur Fuel	108	89	143	13	37	24	8	88
To 500 ppm Fuel	143	118	190	18	49	32	10	118
Total Downgrade	251	206	333	31	86	55	18	206
Highway Fuel Based Downgrade								
Highway Fuel Supply	15,825	18,487	9,527	2,981	3,254	161	60	5,223
To High Sulfur Fuel	348	407	210	66	72	4	1	115
To 500 ppm Fuel	464	542	279	87	95	5	2	153
Total Downgrade	812	948	489	153	167	8	3	268

The downgraded jet fuel and highway diesel fuel are cut directly into batches of high sulfur distillate being carried in the pipeline. Therefore, it is reasonable to assume that this downgrade would be distributed just as the rest of the high sulfur distillate supply. Thus, we allocate this downgrade to the four high sulfur distillate markets in proportion to the demand for each of these fuels in each region. The final projections of production, spillover, downgrade and demand for 2006-2010 for the Reference Case which assumes no implementation of this NRLM rule are shown in Table 7.1.3-8.

Table 7.1.3-8
Distillate Supply and Demand for the Reference Case: 2006-2010 (million gallons in 2014)[M]

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	14,363	16,648	8,616	2,658	2,928	152	56	45,436	4,978	50,377
	Production 500 ppm	866	1,213	532	219	200	8	4	3,029	0	3,066
	Spillover to Non-hwy	-425	-2090	-939	-633	-404	-4	-13	-4508	-1053	-5561
	Hwy Downgrade	-680	-724	-379	-104	-126	0	0	-2012	-173	-2185
	Jet Downgrade to 500 ppm	126	90	137	11	52	0	0	416	0	416
	15 ppm Hwy Downgrade to 500 ppm	453	452	235	62	73	0	0	1,276	0	1,276
	Demand 15 ppm	13,306	14,169	7,420	2,029	2,463	149	44	39,580	3,752	43,332
	Demand 500 ppm	1,416	1,508	790	216	262	8	2	4,201	0	4,201
Non-road	Production HS	3,626	3,726	1,445	290	408	30	39	9,565	10	9,575
	Hwy Spillover	206	1,535	345	450	333	4	3	2,877	1,054	3,930
	Jet Downgrade to 500*	2	9	6	2	6	0	0	25	0	25
	Hwy Downgrade to 500*	6	44	10	12	9	0	0	82	0	82
	Jet Downgrade to HS	32	59	40	8	42	0	0	181	0	181
	Hwy Downgrade to HS	115	297	68	47	59	0	0	586	0	586
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production HS	500	755	739	90	53	5	0	2,143	0	2,143
	Hwy Spillover	14	287	141	128	40	0	0	611	0	611
	Jet Downgrade to HS	5	12	20	2	5	0	0	45	144	189
	Hwy Downgrade to HS	16	60	35	14	7	0	0	133	217	350
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production HS	443	222	938	0	12	69	20	1,704	0	1,704
	Hwy Spillover	13	84	179	0	9	0	1	287	0	287
	Jet Downgrade to HS	4	3	26	0	1	0	0	35	46	81
	Hwy Downgrade to HS	15	18	44	0	2	0	0	78	59	137
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,514	484	1,440	37	30	199	114	8,819	0	8,819
	Hwy Spillover	191	184	274	53	22	0	8	734	0	734
	Jet Downgrade to HS	57	8	39	1	3	0	0	108	0	108
	Hwy Downgrade HS	206	38	67	6	4	0	0	321	0	321
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

* Highway and jet downgrade to 500 ppm spillover pool. This is not shown for other PADDs.

[M] Due to a miscalculation , the jet fuel downgrade is about 10 percent lower than if calculated as described. This error results in slightly overestimating the cost and the benefits of the program. This miscalculation occurred in all the volume analyses prior to 2010.

In 2010, the temporary compliance option of the highway program ends. Therefore, there would not be any 500 ppm highway fuel, only 15 ppm highway fuel and high sulfur distillate. The pipeline sequence shown in Figure 7.1-2 applies. All of the downgrade volumes shown in Table 7.1.3-6 would still apply. No downgraded distillate fuel would meet a 15 ppm cap. Therefore, all the downgraded distillate would be shifted to the high sulfur distillate market. As for 2006-2010, we assume that this downgrade is distributed to the four high sulfur distillate markets in proportion to the demand for each fuel in each region. The projections of production, spillover, downgrade and demand for 2010 and beyond for the Reference Case which assumes no implementation of this NRLM rule are shown in Table 7.1.3-9.

Table 7.1.3-9
Distillate Supply and Demand for the Reference Case: 2010+ (million gallons in 2014)

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15	15,825	18,487	9,527	2,981	3,254	161	60	50,294	5,223	55,517
	Spillover to Non-	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-1,053	-5,561
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production HS	3,401	3,235	1,275	221	242	30	39	8,443	10	8,453
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	1,054	3,930
	Jet Downgrade	108	199	133	28	142	0	0	610	0	610
	Hwy Downgrade	272	702	160	111	140	0	0	1,385	0	1,385
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production HS	469	647	646	66	30	5	0	1,863	0	1,863
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	15	40	69	8	18	0	0	150	144	294
	Hwy Downgrade	38	140	81	33	18	0	0	310	217	527
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production HS	416	190	820	0	7	69	20	1,521	0	1,521
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	13	12	86	0	4	0	0	114	46	161
	Hwy Downgrade	33	41	103	0	4	0	0	181	59	241
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,097	414	1,257	27	17	199	114	8,125	0	8,125
	Hwy Spillover	192	184	274	53	22	0	8	734	0	734
	Jet Downgrade	194	25	131	3	10	0	0	364	0	364
	Hwy Downgrade	488	90	158	14	10	0	0	759	0	759
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.3.2.2 Final NRLM Fuel Program: 2007-2010

Demand for the various categories of distillate fuel are assumed to not change under the final NRLM fuel program. Therefore, the fuel demand estimates shown in Table 7.1.3-5 apply to this scenario, as well as prior to the NRLM rule. We also assume that spillover will not be affected by the NRLM rule, because spillover occurs where only one fuel is available and this fuel will still be 15 ppm highway fuel. Thus, the production of highway fuel and the spillover of this fuel to the NRLM and heating oil markets will be the same as shown in Tables 7.1.3-5 and 7.1.3-8.

With the initiation of the NRLM fuel program in 2007, 500 ppm NRLM fuel will be widely distributed and available. Thus, pipeline sequencing will be affected. While most 500 ppm fuel is likely to be NRLM fuel, the widespread distribution of 500 ppm NRLM fuel will also facilitate the distribute of 500 ppm highway fuel. In areas with relatively small heating oil markets, such as PADDs 2 and 4 and California, we assume that the heating oil volume will be too small to justify pipelines handling a separate high sulfur distillate fuel for this market. Thus, 500 ppm NRLM fuel will replace high sulfur distillate in the common carrier distribution systems in these regions. Generally, this means that most heating oil in these regions will meet a 500 ppm cap.

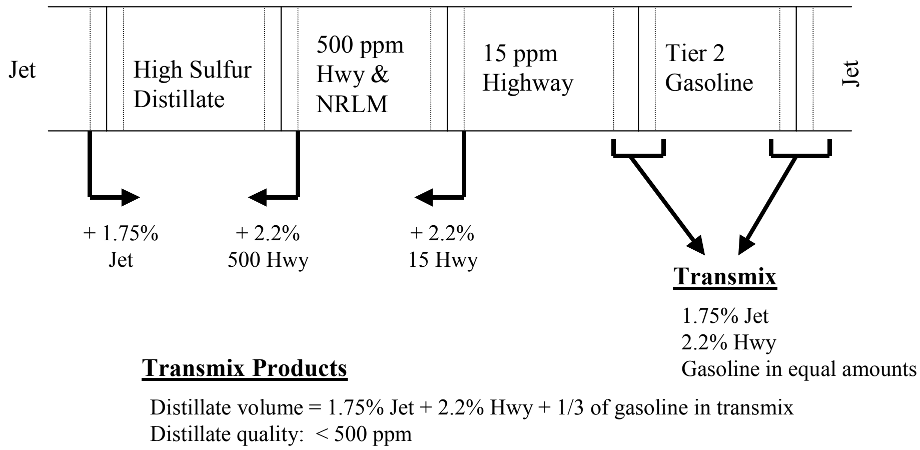
Outside of PADDs 2 and 4, we believe that the heating oil market is either sufficiently large or the distribution system is sufficiently flexible to allow the distribution of high sulfur distillate fuel to this market. The pipelines in PADD 1 are expected to carry heating oil for the large market there, and PADD 3 pipelines are expected to carry heating oil, in part, to supply the PADD 1 market. The heating oil market in the Pacific Northwest is not large. However, this area has a fairly simple distribution system and much of this heating oil consumption is believed to be on the coast. Thus, we believe that it would be feasible for a refiner to produce and distribute high sulfur distillate fuel to this market, though this distribution will not likely be by pipeline. The same is true for Hawaii. Table 7.1.3-10a summarizes these assumptions for the various regions.

Table 7.1.3-10a
Production and Distribution of High Sulfur Distillate: Final NRLM Rule: 2007-2010

	PADDs 1&3	PADDs 2 & 4	PADD 5-O	AK and HI	CA
High Sulfur Distillate in Pipelines	Yes	No	No	No pipelines	No
High Sulfur Distillate Produced for Heating Oil Market	Yes	No	Yes	Yes	No

Figures 7.1-3 depicts pipeline sequencing with 500 ppm NRLM fuel and heating oil both being carried. As shown in Table 7.1.3-10, this applies to pipelines in PADDs 1 and 3.

Figure 7.1-3 Pipeline Sequence and Fate of the Interface Between Fuel Batches in Areas that Carry Heating Oil; After NRLM Rule: 2007 - 2010



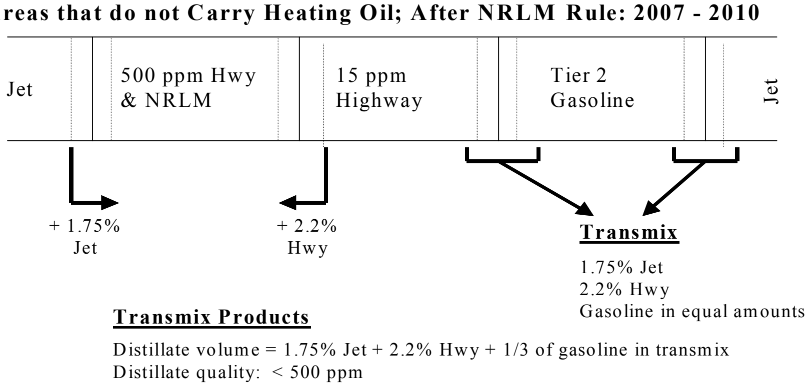
In this case, 15 ppm highway diesel fuel is downgraded directly to batches of 500 ppm fuel in the pipeline. A similar volume of 500 ppm fuel will be downgraded to high sulfur heating oil. Thus, there will be essentially no net loss of 500 ppm fuel from its batch during distribution. The loss of 15 ppm highway fuel is essentially shifted to high sulfur distillate. The interfaces containing gasoline and distillate are not affected, relative to that occurring prior to the NRLM rule. Thus, the net downgrade of 15 ppm highway diesel fuel, jet fuel and heavy gasoline is the same as that prior to the NRLM rule during this timeframe. The distillate fuel produced from transmix should still contain less than 500 ppm sulfur and can be sold to either the highway or NRLM fuel market. We generally presumed that this fuel would be sold to the highway fuel market, given the higher prices likely to exist there. However, under the designate and track provisions of the final NRLM rule, the total volume of highway fuel cannot increase during shipment. Thus, the net loss of 15 ppm highway fuel to the high sulfur distillate market must be greater than the increase in 500 ppm highway fuel from transmix distillate. Therefore, we limited the volume of transmix distillate shifted to the 500 ppm highway fuel market to the volume of 15 ppm highway fuel lost. Any remaining 500 ppm fuel produced from transmix was sent to the 500 ppm NRLM market. A detailed description of these downgrades and their volumes is shown in Table 7.1.3-10.

Table 7.1.3-10
Types of Downgrade and Their Volumes Under the NRLM Rule: 2007-2010
Pipelines Carrying Both 500 ppm NRLM Fuel and High Sulfur Distillate (PADDs 1 and 3)

Interface	Original Fuel	Destination	Volume
Jet Fuel- High Sulfur Distillate Interface	High Sulfur Distillate	High Sulfur Distillate	Zero
	Jet Fuel	High Sulfur Distillate	1.75% of jet fuel demand
Gasoline - Jet Fuel Interface	Jet Fuel	500 ppm Highway Fuel	1.75% of jet fuel demand
	Gasoline	500 ppm Highway Fuel	Equivalent to 0.58% of jet fuel demand
Highway Diesel Fuel- 500 ppm NRLM Fuel Interface	Highway Diesel Fuel	500 ppm NRLM Fuel	2.2% of highway diesel fuel supply
500 ppm NRLM Fuel - High Sulfur Distillate Interface	500 ppm NRLM Fuel	High Sulfur Distillate	2.2% of highway diesel fuel supply
Gasoline - Highway Diesel Fuel Interface	Highway Diesel	500 ppm Highway Fuel	2.2% of highway diesel fuel supply
	Gasoline	500 ppm Highway Fuel	Equivalent to 0.73% of highway diesel fuel supply

Figure 7.1-4 depicts pipeline sequencing in systems that no longer carry high sulfur heating oil. This applies to pipelines in PADDs 2, 4 and 5.

Figure 7.1-4 Pipeline Sequence and Fate of the Interface Between Batches in Areas that do not Carry Heating Oil; After NRLM Rule: 2007 - 2010



The absence of high sulfur distillate in the pipeline affects the types of downgrade occurring. Both downgraded 15 ppm highway diesel fuel and jet fuel are cut directly into batches of 500 ppm fuel in the pipeline. The interfaces containing gasoline and distillate are not affected by the NRLM rule during this timeframe. As discussed in Section 7.1.6, the sulfur level of the distillate produced by transmix operators is estimated to be less than 500 ppm.

We made different assumptions regarding the disposition of this downgrade in the four applicable regions due to varying circumstances existing in each one. Because of the small size of the heating oil market in PADDs 2 and 4 (see Table 7.1.3-8), we assume that refiners will not produce high sulfur distillate fuel for the heating oil market. Thus, in these areas, we assume that this downgraded distillate will preferentially fulfill remaining heating oil demand. This might entail some additional distribution costs to reach all heating oil users, but no sulfur content testing would be required. If the volume of downgrade exceeded heating oil demand in these areas, we assumed that the downgrade would then be used in the 500 ppm highway fuel market, up to the volume of 15 ppm highway fuel lost during distribution(due to designate and track limitations). Any remaining downgrade distillate was assumed to be used as 500 ppm NRLM fuel, in proportion to each region's demand for nonroad, locomotive and marine fuel.

In California, we also assumed that refiners would not produce high sulfur distillate fuel for the heating oil market. However, California's regulations require that all highway and nonroad fuel meet a 15 ppm cap in this timeframe. Also, we project essentially no demand for heating oil in California. Thus, all downgrade distillate was assumed to be used in the L&M markets, in proportion to the demand for each fuel.

Finally, in PADD 5-O, we assumed that refiners could produce high sulfur distillate for the heating oil market, but that this would not be shipped inland in pipelines. Therefore, we assumed that the downgrade distillate would not be used to fulfill heating oil demand, but would be used as 500 ppm highway fuel up to the point allowed by the designate and track procedures. The remainder would then be used as 500 ppm NRLM fuel, in proportion to the region's demand for nonroad, locomotive and marine fuel. Table 7.1.3-11 summarizes these priorities of downgrade use in PADDs 2, 4, and 5 from 2007 - 2010 uncer the fuel rule provisions.

Table 7.1.3-11
Use of Distillate Downgrade by Region: Final NRLM Rule: 2007 to 2010

	PADD 2	PADD 4	PADD 5-O	CA
1st Priority	HO	HO	500 ppm Highway *	L&M
2nd Priority	500 ppm Highway *	500 ppm Highway *	500 ppm NRLM	-
3rd Priority	500 ppm NRLM	500 ppm NRLM	-	-

* Volume limited by loss of 15 ppm highway fuel

Table 7.1.3-12 shows the sources of downgrades and their volumes.

Table 7.1.3-12
Types of Downgrade and Their Volumes Under the NRLM Rule: 2007-2010
Pipelines Not Carrying High Sulfur Distillate (PADDs 2, 4, 5-O, California)

	Original Fuel	Quality of Downgrade *	Volume
Jet Fuel- 500 ppm Diesel Fuel	Jet Fuel	500 ppm Diesel Fuel	1.75% of jet fuel demand
Gasoline - Jet Fuel Interface	Jet Fuel	500 ppm Diesel Fuel	1.75% of jet fuel demand
	Gasoline	500 ppm Diesel Fuel	Equivalent to 0.58% of jet fuel demand
15 ppm Highway Diesel Fuel- 500 ppm Diesel Fuel Interface	Highway Diesel Fuel	500 ppm Diesel Fuel	2.2% of highway diesel fuel supply
Gasoline - Highway Diesel Fuel Interface	Highway Diesel	500 ppm Diesel Fuel	2.2% of highway diesel fuel supply
	Gasoline	500 ppm Diesel Fuel	Equivalent to 0.73% of highway diesel fuel supply

* Destination of the new 500 ppm diesel fuel varies by region.

One last effect of the NRLM rule during the 2007-2010 timeframe is the provision for small refiners to be able to sell high sulfur distillate fuel to the NRLM market. If a small refiner chooses to produce 500 ppm NRLM fuel, then they can sell credits to other refiners, which allows them to produce and market high sulfur NRLM fuel. In either case, the volume of fuel potentially affected by this provision is the production of high sulfur distillate fuel by small refiners. The production of both highway fuel and high sulfur distillate by small refiners is addressed in Section 7.2.1. Since so much of the fuel produced in PADD 3 is distributed to PADD 1, we spread the volume of PADD 3 small refiner fuel over the two PADDs in proportion to the demand for NRLM fuel in the two PADDs.[N] Within each PADD we assume that the high sulfur, small refiner NRLM fuel is blended into the nonroad, locomotive and marine markets in proportion to the demand in each market. The volume of small refiner fuel is summarized in Table 7.1.3-13.

[N] The final NRLM rule includes an Northeast/Mid-Atlantic Area within which no high sulfur NRLM fuel can be sold. This area covers the most of the Northeast and Middle Atlantic states. Thus, it might be difficult for the levels of small refiner fuel assumed here to be sold in PADD 1 under these provisions. If this were the case, this small refiner fuel would likely stay in PADD 3. The net result would be that the sulfur content of NRLM fuel in PADD 1 would decrease and that in PADD 3 would increase. The net nationwide impact would be negligible.

Table 7.1.3-13
Small Refiner NRLM Fuel: 2007-2010 (million gallons)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
420	140	291	0	60	104	0	0

The final projections of production, spillover, downgrade and demand under the final NRLM fuel program from 2007-2010 are shown in Table 7.1.3-14.

Table 7.1.3-14
Distillate Supply and Demand: Final Rule: 2007-2010 (million gallons in 2014)[O]

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	14,363	16,648	8,616	2,658	2,928	152	56	45,436	4,760	50,196
	Production 500 ppm	866	1,213	532	219	200	8	4	3,029	0	3,029
	Spillover to Non-Hwy	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Dwngr 15 ppm	-678	-714	-375	-101	-124	0	0	-1,991	-173	-2,164
	Jet Downgrade	130	107	139	15	52	0	0	437	0	437
	Hwy Downgrade	466	542	239	85	73	0	0	1,378	0	1,378
	Demand 15 ppm	13,284	13,986	7,357	1,973	2,427	148	44	39,219	3,752	42,971
	Demand 500 ppm	1,438	1,690	853	271	299	8	3	4,562	0	4,562
Non-road	Production 500 ppm	3,448	4,025	1,402	329	330	0	39	9,573	10	9,584
	Small Refiner Fuel	333	111	135	0	52	30	0	661	0	661
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	0	0	11	5	59	0	0	75	0	75
	Hwy Downgrade	0	0	19	26	83	0	0	129	0	129
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco motive	Production 500 ppm	476	805	710	98	41	0	0	2,130	0	2,130
	Small Refiner Fuel	46	22	69	0	7	5	0	148	0	148
	Hwy Spillover	15	287	141	129	40	0	0	611	0	612
	Jet Downgrade	0	0	6	1	7	0	0	15	141	159
	Hwy Downgrade	0	0	10	8	10	0	0	28	213	245
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	421	236	901	0	9	0	20	1,588	0	1,588
	Small Refiner Fuel	41	7	87	0	1	69	0	205	0	205
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	0	0	7	0	2	0	0	9	46	55
	Hwy Downgrade	0	0	13	0	2	0	0	15	59	74
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,329	0	1,210	0	37	199	115	7,888	0	7,888
	Hwy Spillover	192	184	274	53	22	0	8	734	0	734
	Jet Downgrade	98	88	124	7	0	0	0	316	0	316
	Hwy Downgrade	351	442	212	38	0	0	0	1,043	0	1,043
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

[O] Due to a miscalculation , the jet fuel downgrade is about 10 percent lower than if calculated as described. This error results in slightly overestimating the costs and the benefits of the program. This miscalculation occurred in all the volume analyses prior to 2010.

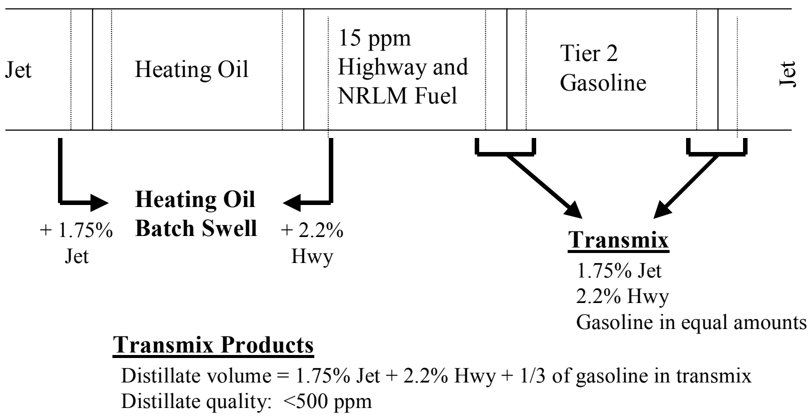
7.1.3.2.3 Final Rule Program - 2010 to 2012

Beginning in mid-2010, two regulatory requirements change: 1) the temporary compliance option under the highway fuel program ends and all highway fuel must meet a 15 ppm cap and 2) nonroad fuel must meet a 15 ppm cap (L&M fuel continues to meet a 500 ppm cap). However, downgraded 500 ppm fuel produced during shipment of 15 ppm highway diesel fuel and jet fuel (or produced by small refiners or with small refiner credits) can continue to be sold to the NRLM fuel markets outside of the Northeast/Mid-Atlantic Area. Within the Northeast/Mid-Atlantic Area, downgraded 500 ppm fuel produced during shipment of 15 ppm fuel and jet fuel can only be sold to the L&M fuel market.

As was the case from 2007-2010, the demand for each distillate fuel and the spillover of highway fuel into these markets are assumed to remain unchanged from those occurring prior to the NRLM rule (see Table 7.1.3-5). With the application of the 15 ppm cap on nonroad fuel in 2010, 500 ppm fuel is not likely to be widely distributed through pipelines. Thus, pipeline sequencing will again be affected. All pipelines will continue to carry 15 ppm fuel, now for both the highway and NRLM markets. Pipelines serving PADD 1 will continue to carry high sulfur distillate for the heating oil market. However, due to the small size of the heating oil markets elsewhere (or the lack of pipelines, as in Alaska and Hawaii), we do not expect that pipelines other than those serving PADD 1 will carry high sulfur distillate. While some pipelines are likely to carry some 500 ppm L&M or small refiner fuel, this is likely to be in proprietary shipments and not as a fungible product. Thus, in assessing pipeline sequencing, we assume that no 500 ppm fuel will be regularly present.

Figure 7.1-5 shows the pipeline sequence for the pipelines in PADDs 1 and 3 which are expected to carry high sulfur heating oil in the 2010-2012 timeframe (applies to the period 2012 - 2014 period as well).

Figure 7.1-5 Pipeline Sequence and Fate of Interface Between Fuel Batches in Areas that Carry Heating Oil; After NRLM Rule: 2010-2012



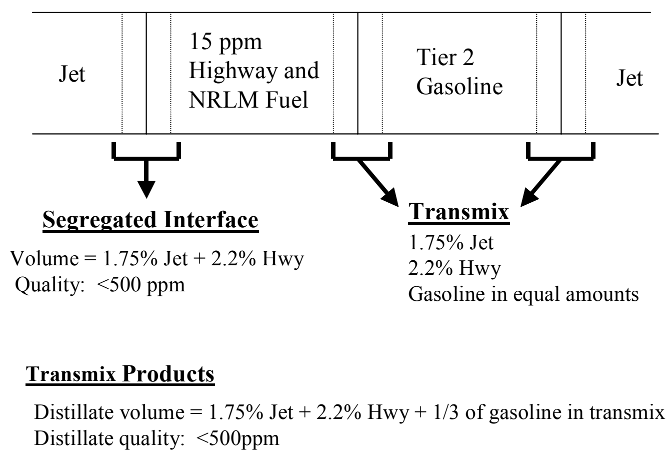
The primary difference between the sequencing in these pipelines in 2010-2012 and 2007-2010 is the elimination of 500 ppm fuel. However, as discussed in Section 7.1.3.2.2, there was no net gain or loss in the size of the 500 ppm batch, as it gained fuel from the adjacent batch of 15 ppm fuel and lost the same volume of 500 ppm fuel to the adjacent batch of high sulfur heating oil. Now, in the absence of the 500 ppm batch, the loss of 15 ppm fuel is cut directly to the heating oil batch in 2010-2012. The quality of the distillate produced from transmix is also the same as in 2007-2010. Thus, the volumes and quality of distillate downgrades remain unchanged from 2007-2010.

The destination of these downgrades changes, however, due to the elimination of the 500 ppm highway fuel market. The downgrades of jet fuel and 15 ppm fuel which are cut directly into the heating oil batch still go directly to the heating oil market. The 500 ppm downgrade material produced from transmix now is assumed to be used in only the NRLM markets, in proportion to the demand for nonroad, locomotive and marine fuel in PADD 3. In most of PADD 1, the Northeast/Mid-Atlantic Area provisions of the final rule prohibit the use of 500 ppm fuel in the nonroad market. As the volume of downgrade produced from transmix in PADD 1 was significantly less than L&M fuel demand, we assumed that all of the distillate produced from transmix in PADD 1 was used in the L&M fuel market from 2010-2012.

It should be noted that we continue to assume that 4.4% of highway diesel fuel supply will be downgraded to protect the quality of 15 ppm diesel fuel. We do not apply the 4.4% downgrade to the new volume of 15 ppm NRLM diesel fuel supply, because the new 15 ppm NRLM fuel is assumed to simply increase the size of the existing batches of 15 ppm highway diesel fuel and not increase the number of interfaces created.

Figure 7.1-6 shows the pipeline sequence for the pipelines in PADDs 2, 4 and 5 which are not expected to carry high sulfur heating oil in the 2010-2012 timeframe (applies to the period 2012 - 2014 period as well).

Figure 7.1-6 Pipeline Sequence and Fate of Interface Between Fuel Batches in Areas that Do Not Carry Heating Oil; After NRLM Rule: 2010-2012



The primary difference between the sequencing in these pipelines in 2010-2012 and 2007-2010 is again the elimination of 500 ppm fuel. Now, in the absence of the 500 ppm batch, the interface between the batch of jet fuel and the batch of 15 ppm fuel can no longer be cut into either fuel. The jet fuel specifications will not allow the addition of No. 2 distillate material due its higher aromatic levels and higher boiling points. The 15 ppm cap will not allow the blending of jet fuel with its much higher sulfur levels. Thus, this interface will have to be segregated from both adjacent batches and stored separately at the terminal. We do not expect that this jet-highway fuel interface will be mixed with other transmix which contains some gasoline. Transmix processors simply separate gasoline from distillate material via distillation. Adding a mixture of jet fuel and highway fuel to a transmix distillation column will just cause all of this material to flow to the distillate product. No separation will occur. Thus, there is no benefit to offset the cost of shipping this distillate transmix to the transmix processor and distilling it. Instead we expect that the terminal will store this interface in a separate tank and sell it directly to a market which can use 500 ppm fuel. In the 2010-2012 timeframe, this is either the NRLM fuel market or the heating oil market. As assumed for 2007-2010 in Section 7.1.3.2.2, in PADDs 2 and 4 from 2010-2012, we assume that this 500 ppm interface will be sold first to the heating oil market and then to the NRLM markets, in proportion to demand. In California, it will be sold to the L&M market. In PADD 5 outside of California, it will be sold to the NRLM markets, in proportion to demand.

The volume of the downgrade from jet fuel and 15 ppm highway fuel to this 500 ppm interface does not change from 2007-2010, as there was no net change in the size of the 500 ppm batch in 2007-2010. The quality of the distillate produced from transmix is also the same as in 2007-2010. Thus, the volumes and quality of distillate downgrades remain unchanged from those in 2007-2010. Table 7.1.3-15 summarizes the destination of downgrade from 2010 to 2012.

Table 7.1.3-15
Blending of Downgrade Under the NRLM Rule: 2010 to 2012

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	CA
1st Priority	HO & L&M	HO	HO & NRLM	HO	NRLM	L&M
2nd Priority	-	NRLM	-	NRLM	-	-

Finally, small refiners can produce and sell 500 ppm fuel to the NRLM markets during this timeframe. We assume that this fuel is generally not distributed in pipelines, so it does not affect the product shipment sequences shown in Figures 7.1-5 and 7.1-6. We expect that the volume of this 500 ppm small refiner fuel will decrease somewhat relative to that in 2007-2010. This occurs because we do not believe that a small refiner would invest to produce 500 ppm NRLM fuel for four years unless they also planned to produce 15 ppm NRLM fuel after 2014. Therefore, we assumed that only those small refiners which our cost analysis shows as competitive with other refiners in producing 15 ppm diesel fuel would produce 500 ppm NRLM fuel in the 2010-2014 timeframe. We assume that the 500 ppm small refiner fuel which is exempted from the 15 ppm nonroad sulfur standard is blended into the nonroad pool. As in 2007-2010, we combined small refiner fuel production in PADDs 1 and 3 and then apportioned it to the two PADDs based on the relative demands for NRLM fuel in each PADD.[P] The volume of 500 ppm small refiner fuel expected to be exempted in each region is summarized in Table 7.1.3-16.

Table 7.1.3-16
Small Refiner Fuel Exempted by Region: 2010 - 2012 (million gallons in 2014)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
261	140	165	4	60	30	0	0

The final projections of production, spillover, downgrade and demand for 2010-2012 under this final NRLM rule are shown in Table 7.1.3-17.

[P] Given the low likelihood that small refiner fuel would be shipped through pipelines, it would have been more realistic to assume that small refiner fuel produced in PADD 3 would be consumed in that region. This has no impact on the nationwide emission reductions projected here. However, a greater volume of small refiner fuel would have been slightly higher emissions of sulfur dioxide and sulfate PM in PADD 3 and slightly lower emissions in PADD 1.

Table 7.1.3-17
Distillate Supply and Demand: Final Rule: 2010-2012 (million gallons in 2014)

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-hwy	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 15 ppm	3,498	3,477	1,215	245	200	0	39	8,674	10	8,684
	Small Refiner Fuel	283	139	136	5	60	30	0	654	0	654
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	0	92	85	18	115	0	0	310	0	310
	Hwy Downgrade	0	427	133	93	149	0	0	801	0	801
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production 500 ppm	195	723	684	74	33	5	0	1,714	0	1,714
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	76	18	43	5	14	0	0	157	144	301
	Hwy Downgrade	251	85	67	28	19	0	0	450	217	667
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	173	212	868	0	7	69	20	1,349	0	1,349
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	67	5	54	0	3	0	0	130	46	176
	Hwy Downgrade	222	25	85	0	4	0	0	337	59	396
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,313	0	1,193	0	37	199	114	7,856	0	7,856
	Hwy Spillover	192	436	215	53	22	0	8	734	0	734
	Jet Downgrade	108	94	137	7	0	0	0	347	0	347
	Hwy Downgrade	357	436	215	37	0	0	0	1,045	0	1,045

7.1.3.2.4 Final Rule Program - 2012 to 2014

Beginning in mid-2012, the sulfur cap applicable to L&M fuel changes from 500 ppm to 15 ppm. Also, 500 ppm fuel produced during shipment of 15 ppm fuel (and by small refiners or using small refiner credits) can continue to be sold to the NRLM fuel markets outside of the Northeast/Mid-Atlantic Area. However, within the Northeast/Mid-Atlantic Area, downgraded distillate or small refiner fuel containing more than 15 ppm sulfur can only be sold as heating oil.

As was the case for 2007-2010 and 2010-2012, the demand for each distillate fuel and the spillover of highway fuel into these markets are assumed to remain unchanged from those occurring in the Reference Case (see Table 7.1.3-5). Since we assumed that 500 ppm L&M fuel would not be widely distributed as a fungible fuel from 2010-2012, the pipeline sequencing described in Figures 7.1-5 and 7.1-6 continue to apply. Thus, the types and volumes of downgrade generated in 2010-2012 will continue in 2012-2014.

The destination of these downgrades stays the same outside of the Northeast/Mid-Atlantic Area, as downgraded distillate can continue to be sold to the NRLM market through 2014 (and to the L&M fuel market thereafter). Within the Northeast/Mid-Atlantic Area, however, downgraded distillate can no longer be sold to the L&M fuel market. Thus, starting in mid-2012, the downgraded distillate generated in the Northeast/Mid-Atlantic Area shifts from the L&M market to the heating oil market, where it displaces high sulfur distillate. This also causes the volume of L&M fuel which must be produced to the 15 ppm cap to be larger than that needed under the 500 ppm cap. The small refiner fuel exempted and blended into the 15 ppm sulfur NRLM diesel fuel pool remains the same as in 2010-2012 except for Alaska. The volume of small refiner fuel eligible for exemptions in Alaska is limited by the volume of the 15 ppm market. The additional production of 15 ppm fuel to satisfy the locomotive and marine market in 2012 in Alaska increases the volume of small refiner fuel exempted there to the total production of NRLM diesel fuel. The volume of small refiner fuel exempted is summarized in Table 7.1.3-18.

Table 7.1.3-18
Small Refiner Fuel Exempted by Region: 2012 - 2014 (million gallons in 2014)

PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	CA
261	140	165	4	60	104	0	0

The final projections of production, spillover, downgrade and demand for 2012-2014 under this final NRLM rule are shown in Table 7.1.3-19.

Table 7.1.3-19
Distillate Supply and Demand: Final Rule: 2012-2014 (million gallons in 2014)

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
Highway	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,054
	Spillover to Non-hw	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Nonroad	Production 15 ppm	3,574	3,506	1,278	246	209	0	39	8,851	10	8,861
	Small Refiner Fuel	207	111	74	3	52	30	0	477	0	477
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	0	92	85	18	115	0	0	310	0	310
	Hwy Downgrade	0	427	133	93	149	0	0	801	0	801
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Locomotive	Production 15 ppm	493	701	647	73	26	0	0	1,931	0	1,931
	Small Refiner Fuel	29	22	37	1	7	5	0	100	0	100
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	0	18	43	5	14	0	0	82	144	226
	Hwy Downgrade	0	85	67	28	19	0	0	203	217	421
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	437	205	820	0	7	0	20	1,489	0	1,489
	Small Refiner Fuel	25	7	48	0	3	69	0	150	0	150
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	0	6	54	0	3	0	0	63	46	109
	Hwy Downgrade	0	26	85	0	4	0	0	116	59	175
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	5,697	0	1,193	0	37	199	114	7,240	0	7,240
	Hwy Spillover	192	184	274	53	22	0	8	734	0	734
	Jet Downgrade	252	94	137	7	0	0	0	490	0	490
	Hwy Downgrade	830	436	215	37	0	0	0	1,518	0	1,518
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.3.2.5 Final Rule Program - 2014 and Beyond

The primary changes occurring in 2014 are: 1) the end of the small refiner provisions and 2) the prohibition on the use of any 500 ppm fuel in the nonroad fuel market. These changes have no effect on fuel demand in any of the markets of interest here. Spillover of highway fuel into the other markets is also assumed to be unaffected, with one exception, as discussed below. As pipelines still carry the same fuels, the volume of each fuel downgraded is also unaffected.

Only the use of 500 ppm downgrade changes, as this fuel can no longer be sold into the nonroad fuel market. Therefore, we assumed that it would be used in either the L&M fuel market or the heating oil market according to the same relative priorities described in Table 7.1.3-15. In a few cases, the volume of downgrade exceeds the demand for all L&M fuel and heating oil in a region, considering the historical level of highway fuel spillover. In those cases, we reduced the volume of spillover of highway fuel into these markets until demand for non-spillover fuel equaled that of the available downgrade. If the volume of available downgrade exceeded total demand for L&M fuel and heating oil in a region (i.e., zero spillover), we assume that the excess downgrade fuel will be returned to a refinery and be reprocessed into 15 ppm fuel. The projections of production, spillover, downgrade and demand for 2014 and beyond under this NRLM rule are shown in Table 7.1.3-20.

Table 7.1.3-20
Distillate Supply and Demand: Final Rule: 2014 and Beyond (million gallons in 2014)

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 15 ppm	3,781	4,136	1,568	321	336	30	39	10,211	10	10,221
	Hwy Spillover	206	1,535	345	490	404	4	4	2,986	835	3,821
	Jet Downgrade	0	0	0	0	0	0	0	0	0	0
	Hwy Downgrade	0	0	0	0	0	0	0	0	0	0
	Reprocessed Downgrade	0	0	0	0	116	0	0	116	219	335
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco motive	Production 15 ppm	522	142	443	0	0	5	0	1,111	0	1,111
	Hwy Spillover	15	287	141	90	0	0	0	532	0	532
	Jet Downgrade	1	122	137	24	46	0	0	328	144	472
	Hwy Downgrade	0	563	215	122	60	0	0	960	217	1,177
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	462	243	894	0	0	69	20	1,687	0	1,687
	Hwy Spillover	13	84	179	0	0	0	1	277	0	277
	Jet Downgrade	0	0	45	0	61	0	0	105	46	151
	Hwy Downgrade	0	0	70	0	78	0	0	149	59	208
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	5,697	0	1,193	0	0	199	114	7,202	0	7,202
	Hwy Spillover	192	184	274	53	0	0	8	712	0	712
	Jet Downgrade	252	94	137	7	26	0	0	516	0	516
	Hwy Downgrade	830	436	215	37	33	0	0	1,552	0	1,552
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.4 Sensitivity Cases

Distillate fuel production and demand were estimated for three sensitivity cases. The first sensitivity case represents an indefinite 500 ppm cap on NRLM fuel that takes effect in 2007 (i.e., no subsequent 15 ppm cap). The second sensitivity case analyzes the proposed rule, which would not require locomotive and marine diesel fuel be desulfurized to 15 ppm. The last sensitivity case analyzes the final rule, but bases the demand for nonroad fuel on information from EIA reports rather than EPA's draft NONROAD2004 model.

7.1.4.1 NRLM Regulated to 500 ppm Indefinitely

To support the legal justification of the 500 ppm cap on NRLM fuel in 2007, we evaluate the costs and benefits of this standard in the absence of a subsequent 15 ppm cap on NRLM fuel. Here, we estimate the production and demand for the various distillate fuels in 2014 under this indefinite 500 ppm cap on NRLM fuel.

During the period from 2007 to 2010, distillate fuel production and demand under this indefinite 500 ppm NRLM fuel cap are assumed to be the same as under the FRM (see Table 7.1.3-14). After 2010, the only differences are the end of the small refiner provisions for producing high sulfur NRLM fuel and the end of the temporary compliance option under the highway fuel program. These two changes are assumed to not affect the demand for the various distillate fuels, nor the spillover of highway fuel into the NRLM fuel and heating oil markets.

The types and volumes of distillate downgrade is not affected, since 500 ppm NRLM fuel will still be carried in all pipelines. However, the disposition of this downgraded distillate is affected slightly, since 500 ppm downgraded distillate can no longer be sold into the 500 ppm highway market. The disposition of downgraded distillate as summarized in Tables 7.1.3-10 through 7.1.3-12 still apply except for the removal of 500 ppm highway fuel as an option for use of this downgraded distillate. The final projections of production, spillover, downgrade and demand for 2010 and beyond under this NRLM rule are shown in Table 7.1.4-1.

Table 7.1.4-1
Distillate Fuel Supply and Demand in 2010 and Beyond (million gallons in 2014)
NRLM at 500 ppm Indefinitely

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 500 ppm	3,293	3,617	1,351	249	261	30	39	8,839	10	8,849
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	114	92	84	18	115	0	0	424	0	424
	Hwy Downgrade	375	427	133	93	149	0	0	1,177	0	1,177
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production 500 ppm	454	723	685	73	33	5	0	1,973	0	1,973
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	16	18	43	5	14	0	0	98	144	242
	Hwy Downgrade	52	85	67	28	19	0	0	255	217	472
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	402	211	869	0	7	69	20	1,578	0	1,578
	Hwy Spillover	13	84	179	0	9	0	1	286	53	339
	Jet Downgrade	14	6	54	0	3	0	0	77	46	123
	Hwy Downgrade	46	26	85	0	4	0	0	161	59	221
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,313	0	1,193	0	37	199	114	7,856	0	7,856
	Hwy Spillover	192	184	274	53	22	0	8	734	0	734
	Jet Downgrade	108	94	137	7	0	0	0	347	0	347
	Hwy Downgrade	357	436	215	37	0	0	0	1,045	0	1,045
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.4.2 Proposed Rule - 500 ppm NRLM Cap in 2007; 15 ppm Nonroad Fuel Cap in 2010

This second sensitivity case evaluates the NRLM fuel program proposed in the NPRM. This case is the same as that proposed, except that the Northeast/Mid-Atlantic Area provisions were added not allowing small refiner fuel and downgrade to be used in the 15 ppm nonroad diesel fuel pool in most of PADD 1 after 2010. Thus, from 2007 to 2012, the program is the same as the final NRLM fuel program. After 2012, the difference is that L&M fuel remains at 500 ppm and that the Northeast/Mid-Atlantic Area restrictions would apply to only the nonroad pool in PADD 1, not the NRLM pool as is the case for the final NRLM program. Since there are no differences between this case and the final NRLM program during the period from 2007 to 2010 the distillate production and demand estimates shown in Table 7.1.3-14 are assumed to apply here, as well.

From 2010 to 2012, there are no differences in the regulatory requirements of the proposed and final NRLM fuel programs. Thus, distillate fuel demand, spillover of highway fuel to non-highway markets, and the types and volume of downgrade are the same under both programs. The small refiner fuel volume exempted from the 15 ppm sulfur standard and is blended into the nonroad diesel fuel pool. The small refiner fuel volume is the same as that summarized in Table 7.1.3-16. Nothing changes in 2012 under the proposed NRLM program. Thus, the production, downgrade, spillover and demand volumes are the same over the entire period from 2010 to 2014. The final projections of production, spillover, downgrade and demand for 2010 to 2014 under this proposed rule sensitivity case are shown in Table 7.1.4-2.

Table 7.1.4-2
Distillate Fuel Supply and Demand in 2010 - 2014 (million gallons in 2014)
15 ppm Nonroad Cap, 500 ppm L&M Cap

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
Highway	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-hwy	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Nonroad	Production 15 ppm	3,498	3,477	1,215	245	200	0	39	8,674	10	8,684
	Small Refiner Fuel	283	139	136	5	60	30	0	654	0	654
	Hwy Spillover	206	1,535	345	451	333	4	4	2,877	835	3,712
	Jet Downgrade	0	92	85	18	115	0	0	310	0	310
	Hwy Downgrade	0	427	133	93	149	0	0	801	0	801
	Reproc. Downgrade	0	0	0	0	0	0	0	0	219	219
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Locomotive	Production 500 ppm	195	723	684	74	33	5	0	1,714	0	1,714
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	76	18	43	5	14	0	0	157	144	301
	Hwy Downgrade	251	85	67	28	19	0	0	450	217	667
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	173	212	868	0	7	69	20	1,349	0	1,349
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	67	5	54	0	3	0	0	130	46	176
	Hwy Downgrade	222	25	85	0	4	0	0	337	59	396
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,313	0	1,193	0	37	199	114	7,856	0	7,856
	Hwy Spillover	192	436	215	53	22	0	8	734	0	734
	Jet Downgrade	108	94	137	7	0	0	0	347	0	347
	Hwy Downgrade	357	436	215	37	0	0	0	1,045	0	1,045

After 2014, the small refiner provisions end and downgraded distillate can no longer be sold to the nonroad fuel market. Downgrade can only be used in the L&M and heating oil markets.

The final projections of production, spillover, downgrade and demand for 2014 and beyond for the proposed rule are shown in Table 7.1.4-3.

Table 7.1.4-3
Distillate Fuel Supply and Demand in 2014 and Beyond (million gallons in 2014)
15 ppm Nonroad Cap, 500 ppm L&M Cap

	Fuel Type	1	2	3	4	5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	15,825	18,487	9,527	2,981	3,254	161	60	50,294	4,760	55,056
	Spillover to Non-hwy	-425	-2,090	-939	-633	-404	-4	-13	-4,508	-835	-5,343
	Hwy Downgrade	-678	-721	-378	-103	-125	0	0	-2,006	-173	-2,178
	Demand	14,722	15,676	8,210	2,245	2,725	157	46	43,781	3,752	47,533
Non-road	Production 15 ppm	3,781	4,136	1,568	323	338	30	39	10,215	10	10,225
	Hwy Spillover	206	1,535	345	488	404	4	4	2,985	835	3,820
	Jet Downgrade	0	0	0	0	0	0	0	0	0	0
	Hwy Downgrade	0	0	0	0	0	0	0	0	0	0
	Reprocessed Downgrade	0	0	0	0	116	0	0	116	219	335
	Demand	3,987	5,670	1,914	810	857	34	43	13,316	1,064	14,379
Loco-motive	Production 500 ppm	195	142	443	0	0	5	0	816	0	816
	Hwy Spillover	15	287	141	90	0	0	0	1,106	0	1,106
	Jet Downgrade	76	122	137	24	46	0	0	399	144	543
	Hwy Downgrade	251	563	215	122	60	0	0	1,183	217	1,401
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	172	243	894	0	0	69	20	1,398	0	1,398
	Hwy Spillover	13	84	179	0	0	0	1	277	0	277
	Jet Downgrade	67	0	45	0	61	0	0	173	46	219
	Hwy Downgrade	222	0	70	0	78	0	0	371	59	430
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,313	0	1,193	0	0	199	114	7,819	0	7,819
	Hwy Spillover	192	184	274	53	0	0	8	712	0	712
	Jet Downgrade	108	94	137	7	26	0	0	373	0	373
	Hwy Downgrade	357	436	215	37	33	0	0	1,079	0	1,079
	Demand	6,970	714	1,820	98	59	199	122	9,981	0	9,981

7.1.4.3 Final NRLM Fuel Program With Nonroad Fuel Demand Derived from EIA FOKS and AEO

This sensitivity case evaluates the final NRLM fuel program assuming a reduced level of nonroad fuel demand. As discussed in Section 2.4.5 of the Summary and Analysis document for this rule, a number of commenters claimed that EPA's NONROAD model overestimates nonroad fuel demand. To ensure that uncertainties in the level of nonroad fuel demand do not affect the decisions being made in this NRLM rule, we evaluate the cost, emission reductions and cost effectiveness of the final NRLM fuel program using an estimate of nonroad fuel demand derived from EIA's FOKS and AEO reports. Thus, the first step in this sensitivity analysis is to derive this lower nonroad fuel demand. Then, we will discuss how this affects spillover, downgrade and production of the various distillate fuels.

We based nonroad fuel demand for the purpose of estimating fuel costs in the NPRM on the information contained in EIA's FOKS and AEO reports. The methodology used here is essentially the same as that used in the NPRM. The primary difference is the use of more recent EIA FOKS and AEO reports. In the NPRM, we used the 2000 FOKS and 2002 AEO reports. Here, we use the 2001 FOKS and 2003 AEO reports. We start with our derivation of nonroad fuel demand in 2001 using 2001 FOKS and then adjust this estimate for growth using 2003 AEO.

7.1.4.3.1 Nonroad Fuel Demand in 2001 Derived from EIA FOKS

This section describes our methodology for deriving nonroad fuel demand from information collected and projections made by EIA. For a more detailed description of the EIA FOKS information collection process and how estimates of nonroad fuel can be derived from it, the reader is referred to the draft RIA for this rule. As described in Section 7.1.2, EIA's FOKS estimates distillate demand in eleven economic sectors. FOKS also breaks down the distillate demand for several of these sectors according to the physical type of distillate used. Table 7.1.4-4 presents the "adjusted" estimated of distillate fuel demand for PADD 1 from the 2001 FOKS report.

Table 7.1.4-4
Nonroad Fuel Demand, PADD 1 Estimates from 2001 FOKS

End Use	Fuel Grade	Distillate* (M gal)	Diesel (%)	Diesel (M gal)	Nonroad (%)	Nonroad (M gal)
Farm	diesel	447	100	447	100	447
	distillate	41	0	0	0	0
Construction	distillate	550	95	523	100	523
Other/(Logging)	distillate	149	95	142	100	142
Industrial	No. 2 fuel oil	226	0	0	0	0
	No. 4 distillate	40	0	0	0	0
	No. 1 distillate	1	40	0.4	100	0.4
	No. 2 low-S diesel	118	100	118	100	118
	No. 2 high-S diesel	374	100	374	100	374
Commercial	No. 2 fuel oil	1,369	0	0	0	0
	No. 4 distillate	200	0	0	0	0
	No. 1 distillate	2	40	0.8	50	0.4
	No. 2 low-S diesel	450	100	450	0	0
	No. 2 high-S diesel	203	100	203	100	203
Oil Company	distillate	21	50	10.5	100	11
Military	diesel	45	100	45	85	38
	distillate	28	0	0	0	0
Electric Utility	distillate	564	100	564	0	0
Railroad	distillate	506	95	481	1.0	5
Vessel Bunkering	distillate	461	90	415	0	0
On-Highway	diesel	10,284	100	10,284	0.7	73
Residential	No. 2 fuel oil	5,464	0	0	0	0
	No. 1 distillate	5	0	0	0	0
Total		21,548	-	14,058		1,934

The key step in our methodology is the estimation of the portion of each sector's fuel demand that is used in nonroad engines. These percentages are summarized in Table 7.1.4-4. We describe these estimates below.

Farm. FOKS estimates fuel demand in this sector for two fuel grades: "diesel fuel" and "distillate." We assume that 100 percent of the diesel fuel represents nonroad use, and 100 percent of the distillate represents uses other than in nonroad engines, such as heating and crop drying.

Construction/Other Off-Highway(Logging). For the construction and logging/other-non-highway end uses, we assume that 95 percent of the total distillate sold is diesel fuel, and that 100 percent of the diesel fuel is used in nonroad engines.

Industrial. FOKS breaks down distillate sales in this sector into five individual fuel grades: No. 1 distillate, low sulfur No. 2 diesel, high sulfur No. 2 diesel fuel, high sulfur No. 2 fuel oil and No. 4 distillate. No. 4 distillate is not covered by the NRLM rule and is rarely used in nonroad engines, if at all. Therefore, we exclude all sales of No. 4 distillate from our estimate of nonroad fuel use. Since sales of No. 2 diesel fuel and No. 2 fuel oil are categorized separately, we assume that no No. 2 fuel oil is used in diesel engines. Thus, no No. 2 fuel oil sales are assumed to fall into nonroad fuel demand. Conversely, we assume that all No. 2 diesel fuel, low-sulfur and high-sulfur, is used in diesel engines and that all of this diesel fuel represents nonroad use. As will be seen below, the low sulfur diesel fuel in the commercial sector is most often used in highway vehicles owned by "commercial" entities not subject to highway excise taxes. We are not aware of any "industrial" entities which are not subject to the excise tax. Thus, should an industrial entity use this low sulfur diesel fuel in a highway vehicle that it owns, this use would be included in the FOKS estimate of highway diesel fuel sales, since the latter is based on excise tax receipts. Therefore, it is reasonable to assume that the low sulfur diesel fuel is not used in highway vehicles. The industrial sector does not include either locomotives or marine vessels. Thus, the non-highway diesel engines must be either nonroad engines or stationary diesel engines likely used for power generation. We assume that the latter use is negligible. For the remaining category, No. 1 distillate, diesel and fuel oil are not distinguished. After consulting with EIA staff, we estimate that 40 percent of No. 1 distillate sales represent diesel fuel, that 100 percent of this diesel represents nonroad use, and that the remainder represents No. 1 fuel oil used in other applications, such as space heating.

Commercial. As with the industrial end use, distillate sales in this sector are reported by fuel grade. As in the industrial sector, we assume that none of the No. 2 fuel oil, and No. 4 fuel represents nonroad diesel fuel. However, in the commercial sector, we assume that all low sulfur diesel fuel sold is used in highway vehicles. This sector includes school-bus and government (local, state and federal) fleets. Fuel used by these fleets are exempt from the federal excise tax, as is fuel for nonroad use. Thus, we assume that none of the low-sulfur No. 2 diesel fuel sold to this sector is used in nonroad engines. As in the industrial sector, we assume that 100 percent of the high-sulfur No. 2 diesel fuel sold is used in nonroad engines. Also as in the industrial sector, after consultation with EIA staff, we estimate that 40 percent of the No. 1 distillate sold is diesel fuel. However, due to the presence of public fleet fuel use in this sector, we estimate that only 50 percent of this diesel fuel is used in nonroad engines.

Oil Company. Sales to this sector include fuel purchased for drilling and refinery operations. We assume that 50 percent of the reported distillate is diesel fuel, and that all of this diesel fuel is used in nonroad equipment. We assume that the remainder represents other uses such as underground injection under pressure to fracture rock.

Military. Fuel sales to the military are reported as being either diesel fuel or distillate. We assume that 85 percent of diesel fuel sales is used in 'non-tactical' nonroad equipment, and that none of the distillate sales represents nonroad use. We assume that 15% of the diesel fuel is not used in nonroad engines because the NONROAD model does not attempt to represent fuel use or emissions from 'tactical' military equipment, such as tanks and personnel carriers because they are not covered by EPA emission standards.

Railroad. We believe that the vast majority of fuel sales to railroads is used by locomotives. Based on guidance from a major railroad, we assume that a small fraction (1%) of reported fuel sales is used in nonroad equipment operated by railroads.

Electric Utility, *Vessel Bunkering* and *Residential.*, We assume that all of the fuel sold to these sectors falls into our definition of marine fuel or heating oil and that none of it is used in nonroad engines..

The EIA FOKS report presents fuel sales by sector for each region of interest here. Thus, we applied the diesel fuel and nonroad percentages shown in Table 7.1.4-4 to the fuel sales in each sector and region to estimate nonroad fuel demand. The results are summarized in Table 7.1.4-5.

Table 7.1.4-5
2001 Nonroad Fuel Consumption Derived From EIA FOKS (million gallons)

End Use	Fuel Grade	Region							
		1	2	3	4	5-O	AK	HI	CA
Farm	diesel	447	1,764	627	155	90	0	7	281
	distillate	0	0	0	0	0	0	0	0
Construction	distillate	523	572	425	118	83	7	3	251
Other/(Logging)	distillate	142	66	136	21	23	3	0	17
Industrial	No. 2 fuel oil	0	0	0	0	0	0	0	0
	No. 4 distillate	0	0	0	0	0	0	0	0
	No. 1 distillate	0.5	8	1	4	0.2	4	0	0
	No. 2 low-S diesel	118	210	196	175	101	2	2	44
	No. 2 high-S diesel	374	355	204	15	66	13	0.6	5
Commercial	No. 2 fuel oil	0	0	0	0	0	0	0	0
	No. 4 distillate	0	0	0	0	0	0	0	0
	No. 1 distillate	0.5	7	0.3	2	0.4	2	0	0
	No. 2 low-S diesel	0	0	0	0	0	0	0	0
	No. 2 high-S diesel	203	155	71	8	19	21	3	3
Oil Company	distillate	11	26	344	10	1.5	14	0	4
Military	diesel	38	15	105	4	50	5	22	24
	distillate	0	0	0	0	0	0	0	0
Electric Utility	distillate	0	0	0	0	0	0	0	0
Railroad	distillate	5	10	8	2	1	0.04	0	2
Subtotal		1,862	3,188	2,119	514	436	69	38	611
Highway (Retail Purchases)	diesel	73	73	50	13	10	3	1	25
Total		1,934	3,261	2,169	527	446	72	39	636

Table 7.1.4-5 shows that, according to the above methodology, the farm, construction, commercial, and industrial categories are the largest consumers of nonroad diesel fuel. Nonroad fuel use on farms is concentrated in PADD 2 (the Midwest), while nonroad fuel demand in the other sectors is spread out more evenly across the nation.

We replaced the year 2001 nonroad fuel demand estimates shown in Table 7.1.2-3 from EPA's NONROAD model with those shown in the last line of Table 7.1.4-5. We recalculated the heating oil demand in each region so that the total fuel demand in the five categories matched the total distillate demand shown. Table 7.1.4-6 shows the revised estimates of fuel demand by region for each of the five usage categories.

Table 7.1.4-6
2001 Distillate Fuel Demand as Derived From EIA FOKS (million gallons)

	Region							
EPA Use Category	1	2	3	4	5-O	AK	HI	CA
Highway Fuel	10,211	10,873	5,694	1,557	1,890	108	32	2,602
Nonroad Fuel	1,934	3,261	2,169	527	446	72	38	637
Locomotive Fuel	476	989	831	209	94	4	0	172
Marine Fuel	415	286	1,037	0	20	60	18	46
Heating Oil	8,512	1,682	1,202	175	249	167	125	146
Total Demand	21,549	17,092	10,932	2,468	2,700	412	214	3,604

The volume of spillover of highway fuel into the four non-highway fuel categories is the same as that shown in Table 7.1.2-5. We considered the volume of unrefunded fuel for this case as well. Since we are basing nonroad fuel demand in this sensitivity case on information contained in FOKS, we adjust both the highway fuel demand and the nonroad fuel demand for unrefunded use of highway fuel in nonroad equipment. The volume of unrefunded fuel is the same as that used for the final rule case, shown in Table 7.1.2-2. The types and volume percentages of downgrade of highway fuel, jet fuel and gasoline are the same as those shown in Table 7.1.2-6. However, we do not show a complete breakdown of production, spillover, downgrade and demand for each usage category and region for 2001 (analogous to that shown in Table 7.1.2-8), since these figures are not used directly in the estimates of either costs, nor emission reductions in this sensitivity analysis.

7.1.4.3.2 Nonroad Fuel Demand in 2014 Derived from EIA AEO 2003

We developed an estimate of nonroad fuel demand in 2014 from EIA's AEO 2003 report. We began with a detailed set of distillate fuel consumption estimates for the various economic sectors presented in AEO 2003. AEO 2003 presents distillate fuel consumption estimates at roughly three levels of detail, as shown in Table 7.1.4-7 below.

Table 7.1.4-7
Distillate Fuel Consumption Demand within AEO 2003

First Level	Second Level	Third Level	Nonroad Fuel Percentage
Total	Transportation	Highway	0.7%
		Rail	1%
		Marine	0%
		Military	76%
	Residential	Residential	0%
	Commercial	Commercial	14%
	Industrial	Farm	98%
		Oil Company	50%
		Construction	95%
		Other *	82%
	Electricity Generation	Electricity Generation	0%

* Not explicitly shown in AEO 2003. Backcalculated from total "Industrial" fuel use.

At the third level of detail from AEO 2003, we utilized distillate fuel consumption estimates from AEO to estimate future nonroad demand. The one exception was the "other" industrial sector. This estimate was obtained by subtracting the demand in the farm, construction and oil company sectors from that in the total industrial sector. We converted all these estimates of fuel consumption from AEO from quadrillion BTU per year to gallons per year using EIA's conversion factor of 138,700 BTU/gal. When available, we estimated the nonroad percentage of each sector's total distillate fuel consumption using the same methodology which we used with the FOKS estimates above. These estimates are available for all the sectors except commercial, "other" industrial, farm, and military. The estimates of the nonroad portion of total distillate demand for these four sectors depended on the type of distillate fuel consumed, such as low sulfur diesel fuel, kerosene, etc. AEO 2003 does not provide projections broken down by the type of distillate fuel, only total distillate. In these cases, we used the nonroad diesel fuel fractions found from the analysis of the 2002 FOKS.[Q] All of these nonroad fuel percentages are shown in Table 7.1.4-8.

Table 7.1.4-8 presents total distillate demand by sector for 2002 and projected total distillate demand for 2014 from AEO 2003, the percentage of each fuel demand that is assumed to be nonroad, and the resulting 2014 nonroad fuel demand by sector.

Table 7.1.4-8
2002 and 2014 Nonroad Diesel Fuel Demand: 2003 AEO (million gallons per year)

Category	Total Distillate Demand		Nonroad Diesel (%)*	Nonroad Diesel Fuel Demand	
Year	2002	2014	2002 & 2014	2002	2014
Commercial	3244	3533	14%	458	498
Other Industrial	2653	3331	82%	2164	2717
Highway	32,242	48,839	0.7%	221	257
Oil Company	43	0	50%	22	0
Farm	3403	3843	98%	3320	3749
Railroad	3669	4196	1%	35	40
Military	800	894	76%	607	678
Construction	1687	1983	95%	1603	1884
Total	---	---	---	8428	9823

* Derived by applying EPA estimates of nonroad fuel use to FOKS 2002 fuel sales.

As shown in Table 7.1.4-8, from information contained in both FOKS 2002 and AEO 2003, total nonroad fuel demand in 2014 is projected to be 9.82 billion gallons per year. This represents a 17% increase over the 8.43 billion gallons demand estimated for 2002, or 1.37% per year linear growth from a 2002 base. The growth rates embedded in AEO 2003 vary slightly from year to year and decade to decade. However, as the purpose of this analysis is simply to evaluate the sensitivity of the cost effectiveness of the NRLM rule to uncertainty in nonroad fuel consumption, we have applied this 1.37% growth rate from 2001 through the final year of analysis, 2040. We based the growth rate off of fuel consumption in 2002, rather than 2001, because FOKS 2002 shows a significant drop in distillate fuel consumption in 2002. The AEO 2003 estimates reflect this decrease in 2002 and projects relatively steady growth starting from 2002. Thus, reflecting

[Q] The projection of nonroad fuel demand using the NONROAD model was already complete and subsequent analyses of emission benefits, monetized benefits and economic impacts were underway when FOKS 2002 was issued in late November 2003. Therefore, it was not possible to utilize FOKS 2002 for the primary estimates presented in this Final RIA. However, it was possible to utilize this more recent information for this sensitivity analysis.

this drop in nonroad diesel fuel consumption in 2002 and steady growth thereafter better reflects the AEO 2003 projections. Projecting growth from 2001 would have reduced the annual growth rate considerably, over-predicting fuel consumption prior to 2014 and under-predicting fuel consumption after 2014.

We used the same 2001-2014 growth ratios for the other four fuel use categories as shown in Tables 7.1.3-1 and 7.1.3-3. These growth ratios were applied to the demand volumes in Table 7.1.4-7 to estimate fuel demand in 2014. We increased the 2001 nonroad fuel consumption of 9.084 billion gallons (shown in Table 7.1.4-7) by 8.14%, which is the total increase between the 2014 fuel demand of 9.823 billion gallons shown in Table 7.1.4-8 and 2001 nonroad fuel demand. These volumes are summarized in Table 7.1.4-9.

Table 7.1.4-9
2014 Distillate Fuel Demand based on AEO 2003 and FOKS 2002 (million gallons)

	Region							
EPA Use Category	1	2	3	4	5-O	AK	HI	CA
Highway Fuel	14,738	15,693	8,221	2,248	2,728	157	47	3,758
Nonroad Fuel	2,104	3,603	2,394	581	492	78	43	691
Locomotive Fuel	536	1114	935	236	106	5	0	194
Marine Fuel	475	327	1187	0	23	69	21	53
Heating Oil	7,898	1,561	1,115	162	231	155	116	136

The volume of spillover of highway fuel into the four non-highway fuel categories is the same as that shown in Table 7.1.3-5. The types and volume percentages of downgrade of highway fuel, jet fuel and gasoline are the same as those shown in Table 7.1.3-6. Jet fuel demand is the same as shown in Table 7.1.3-7. We also used the same methodology to assign downgrade to the various distillate markets. Finally, the volume of NRLM fuel produced by small refiners is the same as that shown in Table 7.1.3-16.

We do not show a complete breakdown of production, spillover, downgrade and demand for each usage category and region for 2010-2014 or 2014 and beyond in a Reference Case (which assumes no implementation of this nonroad rule). This is not necessary because we used a different methodology to estimate the emission reductions for this case than for the final rule case which did not require the estimation of reference case sulfur levels. Tables 7.1.4-10 through 7.4.1-13 present the estimates of distillate demand and production for the four time periods relevant to this nonroad rule: 2007-2010, 2010-2012, 2012-2014, and 2014 and beyond, respectively.

Table 7.1.4-10
Distillate Supply and Demand: Final Rule: 2007-2010 (million gallons in 2014)
Nonroad Fuel Demand Derived from EIA FOKS and AEO [R]

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
High-way	Production 15 ppm	14,347	16,382	8,589	2,601	2,882	152	56	45,030	4,547	49,577
	Prod 500 ppm	860	1822	540	199	181	8	4	3595	0	3595
	Spillover	-388	-1798	-910	-553	-336	-3	-13	-4001	-622	-4623
	Hwy Downgrade 15	-679	-717	-375	-101	-125	0	0	-1,997	-173	-2,170
	Jet Downgrade	129	106	139	15	51	0	0	440	0	440
	Hwy Downgrade	465	534	239	83	71	0	0	1,392	0	1,392
	Demand 15 ppm	13,303	14,048	7,358	1,987	2,441	149	44	39,328	3,752	43,080
	Demand 500 ppm	1,433	1,642	861	261	286	8	3	4,494	0	4,494
Non-road	Production 500 ppm	1,825	2,606	1,807	261	139	28	41	6,706	7	6,712
	Small Refiner Fuel	211	100	212	3	48	49	0	623	0	623
	Hwy Spillover	143	1,025	423	335	200	3	4	2,132	614	2,746
	Jet Downgrade	0	0	14	0	51	0	0	65	0	65
	Hwy Downgrade	0	0	23	2	72	0	0	97	0	97
	Reproc. Downgrade	0	0	0	0	0	0	0	0	95	95
	Demand	2,178	3,730	2,479	601	510	81	44	9,624	715	10,339
Loco-motive	Production 500 ppm	468	797	698	105	29	2	0	2,098	0	2,098
	Small Refiner Fuel	54	31	82	1	10	3	0	181	0	181
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	0	0	5	0	11	0	0	16	85	102
	Hwy Downgrade	0	0	9	1	15	0	0	25	110	135
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 500 ppm	414	234	886	0	6	25	20	1,585	0	1,585
	Small Refiner Fuel	48	9	104	0	2	44	0	207	0	207
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	0	0	6	0	2	0	0	9	64	74
	Hwy Downgrade	0	0	11	0	3	0	0	15	83	98
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	7,233	28	612	0	144	155	109	8,280	0	8,953
	Hwy Spillover	217	402	168	89	87	0	8	971	8	980
	Jet Downgrade	98	187	124	11	0	0	0	419	56	475

[R] The jet and highway-based downgrade volumes shown in this table were over-estimated by 10% and 2%, respectively.

	Hwy Downgrade	351	944	212	63	0	0	0	1,569	72	1,641
	Demand	7,898	1,561	1,115	162	231	155	116	11,239	136	11,375

Table 7.1.4-11
Distillate Supply and Demand: Final Rule: 2010-2012 (million gallons in 2014)
Nonroad Fuel Demand Derived from EIA FOKS and AEO

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
High-way	Production 15 ppm	15,801	18,210	9,507	2,903	3,189	161	59	49,831	4,552	54,383
	Spillover	-388	-1,798	-910	-553	-336	-3	-13	-4,001	-622	-4,623
	Hwy Downgrade	-678	-722	-378	-103	-126	0	0	-2,008	-173	-2,180
	Demand	14,735	15,690	8,219	2,247	2,727	157	47	43,822	3,757	47,579
Non-road	Production 15 ppm	1,835	2,630	1,970	265	182	51	41	6,974	7	6,981
	Small Refiner fuel	283	139	136	5	60	30	0	654	0	654
	Hwy Spillover	145	1,047	431	344	280	3	4	2,256	614	2,870
	Jet Downgrade	0	0	0	0	0	0	0	0	0	0
	Hwy Downgrade	0	0	0	0	0	0	0	0	0	0
	Proc. Downgrade	0	0	0	0	0	0	0	0	96	96
	Demand	2,263	3,816	2,537	616	522	84	45	9,884	715	10,599
Loco-motive	Production 15 ppm	195	821	589	0	0	5	0	1,610	0	1,610
	Hwy Spillover	15	287	141	126	14	0	0	582	0	582
	Jet Downgrade	76	1	80	18	40	0	0	215	85	300
	Hwy Downgrade	250	5	126	92	52	0	0	525	110	635
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	173	241	747	0	0	69	20	1,250	0	1,250
	Hwy Spillover	13	84	179	0	3	0	1	280	0	280
	Jet Downgrade	67	0	102	0	9	0	0	178	65	244
	Hwy Downgrade	222	1	160	0	11	0	0	394	84	479
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	7,217	0	595	0	0	155	108	8,076	0	8,076
	Hwy Spillover	217	402	168	89	44	0	8	928	8	936
	Jet Downgrade	108	206	137	12	81	0	0	544	56	601
	Hwy Downgrade	356	953	215	62	105	0	0	1,691	72	1,764
	Demand	7,898	1,561	1,115	162	231	155	116	11,239	136	11,375

Table 7.1.4-12
Distillate Supply and Demand: Final Rule: 2012-2014 (million gallons in 2014)
Nonroad Fuel Demand Derived from EIA FOKS and AEO

Fuel Use Category	Fuel Type	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK	HI	US - CA	CA	US
Highway	Production 15 ppm	15,801	18,210	9,507	2,903	3,189	161	59	49,831	4,552	54,383
	Spillover	-388	-1798	-910	-553	-336	-3	-13	-4001	-622	-4623
	Hwy Downgrade	-678	-722	-378	-103	-126	0	0	-2,008	-173	-2,180
	Demand	14,735	15,690	8,219	2,247	2,727	157	47	43,822	3,757	47,579
Nonroad	Production 15 ppm	1,903	2,554	1,690	182	25	24	41	6,419	7	6,425
	Small Refiner Fuel	143	100	118	3	48	53	0	455	0	455
	Hwy Spillover	143	1,025	423	335	200	3	4	2,132	614	2,746
	Jet Downgrade	0	9	97	13	103	0	0	222	0	222
	Hwy Downgrade	0	42	152	68	133	0	0	395	0	395
	Proc. Downgrade	0	0	0	0	0	0	0	0	95	95
	Demand	2,178	3,730	2,479	601	510	81	44	9,624	715	9,622
Locomotive	Production 15 ppm	487	781	653	73	5	1	0	2,001	0	2,001
	Small Refiner Fuel	34	31	46	1	10	3	0	125	0	125
	Hwy Spillover	15	287	141	129	40	0	0	611	0	611
	Jet Downgrade	0	3	38	5	22	0	0	69	85	178
	Hwy Downgrade	0	13	60	28	29	0	0	129	109	322
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	432	229	828	0	1	22	20	1,532	-95	1,597
	Small Refiner Fuel	30	9	58	0	2	47	0	147	0	147
	Hwy Spillover	13	84	179	0	9	0	1	286	0	286
	Jet Downgrade	0	1	47	0	5	0	0	53	65	137
	Hwy Downgrade	0	4	74	0	6	0	0	84	84	137
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,602	65	595	4	144	155	108	7,674	0	7,674
	Hwy Spillover	217	402	168	89	87	0	8	971	8	979
	Jet Downgrade	251	194	137	11	0	0	0	593	56	665
	Hwy Downgrade	828	899	215	58	0	0	0	2,001	72	2,073
	Demand	7,898	1,561	1,115	162	231	155	116	11,239	136	11,375

Table 7.1.4-13
Distillate Supply and Demand: Final Rule: 2014 and Beyond (million gallons in 2014)
Nonroad Fuel Demand Derived from EIA FOKS and AEO

Fuel Use Category	Fuel Type	PADD					AK	HI	US - CA	CA	US
		1	2	3	4	5-O					
Highway	Production 15 ppm	15,801	18,210	9,507	2,903	3,189	161	59	49,831	4,552	54,383
	Spillover	-388	-1,798	-910	-553	-336	-3	-13	-4,001	-622	-4623
	Hwy Downgrade	-678	-722	-378	-103	-126	0	0	-2,008	-173	-2,180
	Demand	14,735	15,690	8,219	2,247	2,727	157	47	43,822	3,757	47,579
Nonroad	Production 15 ppm	2,036	2,706	2,056	260	229	77	41	7,404	7	7,411
	Hwy Spillover	143	1,025	423	335	200	3	4	2,132	614	2,746
	Jet Downgrade	0	0	0	0	0	0	0	0	0	0
	Hwy Downgrade	0	0	0	0	0	0	0	0	0	0
	Reproc. Downgrade	0	0	0	0	0	0	0	0	96	96
	Demand	2,178	3,730	2,479	601	510	81	44	9,624	715	10,339
Locomotive	Production 15 ppm	522	755	443	0	0	5	0	1,723	0	1,723
	Hwy Spillover	15	287	141	129	0	0	0	516	0	516
	Jet Downgrade	0	13	136	18	46	0	0	214	85	298
	Hwy Downgrade	0	59	215	95	60	0	0	429	110	539
	Demand	536	1,114	935	236	106	5	0	2,932	194	3,126
Marine	Production 15 ppm	462	243	894	0	0	69	20	1,688	0	1,688
	Hwy Spillover	13	84	179	0	0	0	1	277	0	277
	Jet Downgrade	0	0	45	0	10	0	0	55	65	120
	Hwy Downgrade	0	0	70	0	13	0	0	83	84	167
	Demand	475	327	1,187	0	23	69	21	2,103	53	2,156
Heating Oil	Production HS	6,602	66	595	4	8	155	108	7,538	0	7,538
	Hwy Spillover	217	402	168	89	87	0	8	971	134	1,106
	Jet Downgrade	251	194	137	11	74	0	0	667	56	723
	Hwy Downgrade	828	898	215	58	95	0	0	2,095	72	2,167
	Demand	7,898	1,561	1,115	162	231	155	116	11,239	136	11,375

The primary difference resulting from estimating nonroad fuel demand using FOKS and AEO is that nonroad demand is lower (and therefore, heating oil demand is larger) in PADDs 2, 4, and 5. This eliminates the need to reprocess any downgraded fuel after 2014 when this fuel can only be used in the L&M fuel and heating oil markets.

7.1.5 Methodology for Annual Distillate Fuel Demand: 1996 to 2040

The environmental impact and cost-effectiveness analyses presented in this Final RIA require estimates of fuel demand from 1996 through 2040. This section presents the methodology used to develop these estimates. The actual levels of fuel demand are presented in Section 7.1.6 along with the sulfur contents of the various fuels on an annual basis.

In this section, we develop a set of year-over-year (compound) growth rates from 1996-2040 for the four non-highway fuel categories. We did not address highway fuel demand, as this is not affected by this NRLM rule. For nonroad, locomotive and marine fuels, we obtained annual estimates of fuel demand for as much of this time period as was available. We then calculated year-over-year growth rates over the period of time that the data were available. Finally, we extrapolated or interpolated these growth rates to cover any years for which specific fuel demand projections were not available.

We obtained our estimates of annual fuel demand by nonroad engines from EPA's NONROAD emission model. These estimates of fuel demand and the resulting annual growth rates are shown in Table 7.1.5-1. As can be seen, NONROAD projects a linear increase in fuel consumption over time. This results in a slightly decreasing year-over-year growth rate over time.

Table 7.1.5-1
Annual Growth In the Demand of Nonroad and Locomotive Fuel

Year	Nonroad Fuel Demand (million gallons)	Annual Growth Rate	Locomotive Fuel Demand		Annual Growth Rate
			(trillion btu)	(million gallons)	
1996	9,158			3072	
1997	9,450	1.032			0.969
1998	9,742	1.031			0.968
1999	10,024	1.029			0.967
2000	10,319	1.030	609.2	2692	0.966
2001	10,613	1.028	628.4		1.032
2002	10,906	1.028	610.2		0.971
2003	11,200	1.027	617.0		1.011
2004	11,493	1.026	621.4		1.007
2005	11,787	1.026	626.1		1.008
2006	12,078	1.025	638.9		1.020
2007	12,370	1.024	650.2		1.018
2008	12,661	1.024	657.4		1.011
2009	12,952	1.023	666.3		1.014
2010	13,244	1.023	676.9		1.016
2011	13,537	1.022	689.7		1.019
2012	13,830	1.022	696.6		1.010
2013	14,123	1.021	702.1		1.008
2014	14,416	1.021	707.6		1.007
2015	14,709	1.020	713.5		1.008
2016	14,999	1.020	721.1		1.011
2017	15,289	1.020	727.7		1.009
2018	15,579	1.019	733.1		1.007
2019	15,869	1.019	740.3		1.010
2020	16,159	1.018	745.4		1.007
2021	16,449	1.018	749.2		1.005
2022	16,739	1.018	755.9		1.009
2023	17,029	1.017	762.6		1.009
2024	17,319	1.017	769.2		1.009
2025	17,609	1.017	776.6		1.010
2026	17,897	1.016	-		1.008
2027	18,185	1.016	-		1.008
2028	18,473	1.016	-		1.008
2029	18,761	1.016	-		1.008
2030	19,049	1.015	-		1.008
2031	19,337	1.015	-		1.008
2032	19,625	1.015	-		1.008
2033	19,912	1.015	-		1.008
2034	20,201	1.015	-		1.008
2035	20,489	1.014	-		1.008
2036	20,777	1.014	-		1.007
2037	21,065	1.014	-		1.007
2038	21,353	1.014	-		1.007
2039	21,641	1.014	-		1.007
2040	21,928	1.013	-		1.007

Locomotive diesel fuel growth rates for the period from 1996 to 2000 were estimated from historic estimates of fuel consumption taken from the 1996 and 2000 FOKS reports. We assume that locomotive diesel fuel demand decreased linearly between 1996 and 2000. We assume a constant linear growth rate for this time period, as this seemed most consistent with EIA's projection of growth in locomotive fuel demand in the post-2000 time period. For the period after 2000, we use the annual demand for locomotive diesel fuel projected by EIA in the AEO 2003 to calculate year-over-year growth rates from 2000 to 2025 (the last projection year in AEO 2003). Beyond 2025, we assume that locomotive fuel demand grows linearly at the average rate of growth between 2021 and 2025. The FOKS and AEO estimates of fuel demand and the year-over-year growth rates for locomotive diesel fuel are summarized in Table 7.1.5-1.

According to EIA FOKS reports, the demand for marine diesel fuel decreased slightly between 1996 and 2001. We estimated annual demand for marine diesel fuel for 1997-2000 by assuming a constant compound growth rate between 1996 and 2001. (Constant compound growth is more consistent with EIA's projection of growth in marine fuel demand in the post-2000 time period than constant linear growth.) For the period after 2000, we use the annual demand for marine diesel fuel projected by EIA in the AEO 2003 to calculate a year-over-year growth rates 2000 to 2025 (the last projection year in AEO 2003). Beyond 2025, we assume that marine fuel demand grows at a constant compound growth rate between 2001 and 2025, which was 1.3%. The FOKS and AEO estimates of fuel demand and the year-over-year growth rates for marine diesel fuel are summarized in Table 7.1.5-2.

Table 7.1.5-2
Annual Growth in the Demand for Marine Diesel Fuel

Year	Marine Fuel Consumption		Annual Growth Rate
	AEO 2003 (trillion BTU)	FOKS 2001 (million gallons)	
1996	-	1960	
1997	-	-	0.992
1998	-	-	0.992
1999	-	-	0.992
2000	-	-	0.992
2001	344.6	1884	0.992
2002	338.4	-	0.982
2003	342.6	-	1.012
2004	346.1	-	1.010
2005	348.4	-	1.007
2006	356.5	-	1.023
2007	361.7	-	1.015
2008	366.7	-	1.014
2009	371.1	-	1.012
2010	375.7	-	1.012
2011	381.2	-	1.015
2012	386.1	-	1.013
2013	389.6	-	1.009
2014	394.3	-	1.012
2015	398.7	-	1.011
2016	402.5	-	1.010
2017	407.0	-	1.011
2018	413.1	-	1.015
2019	420.1	-	1.017
2020	425.0	-	1.012
2021	430.2	-	1.012
2022	437.2	-	1.016
2023	442.1	-	1.011
2024	448.0	-	1.013
2025	453.2	-	1.012
2026	-	-	1.013
2027	-	-	1.013
2028	-	-	1.013
2029	-	-	1.013
2030	-	-	1.013
2031	-	-	1.013
2032	-	-	1.013
2033	-	-	1.013
2034	-	-	1.013
2035	-	-	1.013
2036	-	-	1.013
2037	-	-	1.013
2038	-	-	1.013
2039	-	-	1.013
2040	-	-	1.013

We applied a simpler approach to estimating the growth in the demand for heating oil for a number of reasons. One, this rule does not regulate the sulfur content of heating oil. Two, EIA does not present estimates of heating oil demand, as it is defined here. Three, heating oil demand between 2001 and 2014 is very close to zero. Thus, the effect of differing assumptions regarding the shape of this growth, such as linear versus compound, have a negligible effect on any extrapolated growth.

As shown in Table 7.1.3-3, heating oil demand declined by 7% from 2001 to 2014. We assumed that this decline was occurring at a constant compound rate, which we calculated to be -0.006% for this time period. We assumed that this decline would continue through 2040.

7.1.6 Annual Distillate Fuel Demand and Sulfur Content

In this section we estimate the sulfur content of the various types of distillate fuel prior to this rule and how they are affected by the NRLM rule. We then present year-by-year estimates of both distillate fuel demand and sulfur content for the purpose of estimating the environmental benefits of this rule.

7.1.6.1 Sulfur Content

The sulfur content of high sulfur distillate before and after this NRLM rule is used in two ways in this regulatory impact analysis: 1) to estimate the reductions in emissions of sulfur dioxide and sulfate PM, and 2) to estimate the cost of desulfurizing this fuel to meet 500 and 15 ppm caps. In this section we estimate the current sulfur content of the four non-highway distillate fuels by region. We then estimate how these sulfur contents change during the various phases of the final NRLM fuel program. Finally, we estimate the sulfur content of these fuels for two sensitivity cases: 1) a long-term 500 ppm sulfur NRLM program and 2) the proposed NRLM fuel program (15 ppm nonroad fuel and 500 ppm L&M fuel in 2010).

We estimate the current sulfur content of high sulfur distillate from diesel fuel survey data collected by TRW Petroleum Technologies (TRW) at its facility in Bartlesville, Oklahoma. This facility was formerly known as the National Institute for Petroleum and Energy Research (NIPER)). Surveys performed for 1999 through 2002 were published by TRW. Surveys prior to 1999 were published by the NIPER. We evaluated their survey data from 1996 through 2002. As the methodology of conducting the surveys and the presentation of the data have not changed over this time period, we will simply refer to these surveys as TRW surveys.

No comments were received on our methodology for estimating the sulfur content of high sulfur distillate for the NPRM. However, we have made three changes to that analysis which we believe improve the estimate. The first is to include the 2002 survey data, which is now available. The second is to include sample data which were assigned a production volume by TRW. The third is to adjust the sample data for the addition of downgraded jet fuel, highway diesel fuel and heavy gasoline during distribution.

TRW collects sulfur data voluntarily provided by domestic refiners, including a refiner located in the Virgin Islands. These refiners analyze the sulfur content of their diesel fuel production and submit the results to TRW. TRW states that the survey results reflect the average quality of distillate fuel produced at refineries for use in each geographical area. However, TRW also states that the data may not be representative of the full range of sulfur content of these fuels at their point of use. This appears to be due to either TRW or refiners reporting the average quality of their high sulfur diesel fuel versus a set of individual samples, in addition to the effect of convenience sampling.

TRW presents survey results for five geographic regions containing 16 districts. According to TRW, these areas are based on fuel distribution systems, refinery locations, centers of population, temperature zones, and arteries of commerce. A map of the regions and districts is shown in Figure 7.1-6 below. Each sample is assigned to both a region and to one or more districts. We primarily use the TRW district assignments, as they provide a more precise indication of where the fuel was eventually sold. A map of the Petroleum Administration Defense Districts (PADDs) is shown for comparison in Figure 7.1-7. Since all of our estimates for distillate production and demand were developed by PADD (with PADD 5 split up further), we assigned each TRW district to one or more PADDs as described in Table 7.1.6-1.

Figure 7.1-7 TRW Fuel Survey Regions and Districts

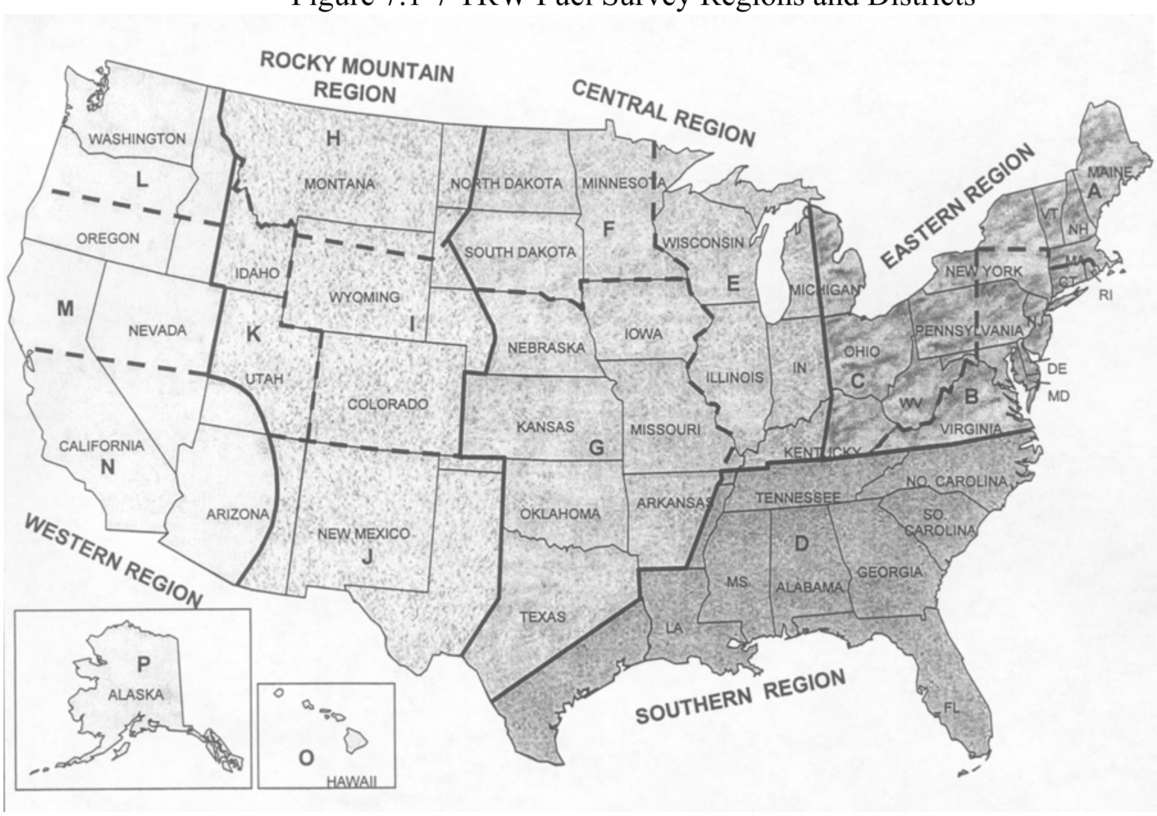


Figure 7.1-8. Petroleum Administration for Defense Districts (PADDs)

Table 7.1.6-1
Assignments of TRW Regions and Districts to PADDs

Region	TRW District	Assigned PADD
Eastern	A	1
	B	1
	C	1, 2
Southern	D	1, 3
Central	E	2
	F	2
	G	2
Rocky Mountain	H	4
	I	4
	J	3
	K	4
Western	L	5
	M	5
	N	5
	O	5
	P	5

TRW provides a rough indication of the annual volume of fuel represented by each sulfur measurement by assigning each data point one of four numbers. Table 7.1.6-2 presents the numbering system used by TRW and the range of diesel fuel production represented by each numeral assignment. In order to weight the sulfur measurements by volume, we assigned an average volume to each range. These averages are also shown in Table 7.1.6-2.

Table 7.1.6-2
Production Volumes of Fuel Sulfur Samples

TRW Sample Quantity Number	Fuel Volume (Barrels Per Year)	
	TRW: Range	EPA: Assumed Average Volume
1	Over 1,500,000	1,500,000
2	500,000 to 1,500,000	1,000,000
3	50,000 to 500,000	275,000
4	Under 50,000	50,000

Within each region, the TRW reports generally list the sulfur samples by their Sample Quantity Number, starting with 1 and moving to 2, 3, and 4. Thus, the sulfur data representing the largest fuel batches are listed first and those representing the smallest fuel batches are listed last. However, some sulfur data points in the TRW reports do not have a Sample Quantity Number. These data points always appear at either top of the list or the bottom of the list. When the data missing a Sample Quantity Number appeared at the top of the list, we assigned that data a production volume of 2 million barrels per year. When the data appeared at the bottom of the list, we assigned it a volume of 25,000 barrels per year. In the analysis performed for the NPRM, we excluded this data from the analysis.

The survey reports often list the same sample number under more than one region. Each of these listings shows the districts in both regions. For example, Sample 45 may be listed in both the Eastern and Central Regions. Both listing show C2 and E2, indicating that 0.5-1.0 million barrels of fuel were shipped that year to Districts C and E. Since both districts are listed under both regions, we assumed that this was in fact only one data point and that 0.5-1 million barrels were shipped to District C in the Eastern Region and that 0.5-1 million barrels were shipped to District E in the Central Region, not twice this volume.

In this case, the numeral 2 was assigned to each district, so we assumed that 0.5-1 million barrels of fuel were provided to each district. In some cases, two or more districts are listed with only a single numeral following the district letter (i.e., C, E 2). In this case, we assumed that the total volume of fuel produced was 0.5-1 million barrels and that this volume was split between the two districts. TRW indicates that the district receiving the most fuel was listed first, etc. However, lacking any quantitative information about the relative volumes of fuel supplied to each district, we simply assumed that each district received the same proportion.

TRW segregates their reporting of fuel quality by fuel type, namely No. 1 diesel fuel, No. 2 highway diesel fuel and No. 2 off-highway diesel fuel. We focused solely on the data for No. 2 off-highway diesel fuel. However, we assumed that off-highway diesel fuel with a sulfur content of less than 500 ppm was highway diesel fuel "spillover." These data were excluded from this analysis since we account for the lower sulfur content of spillover fuel separately below.

After applying the PADD assignments shown in Table 7.1.6-1, we volume weighted the sulfur data in each PADD using the average volumes shown in Table 7.1.6-2 in order to derive a PADD average sulfur content for each calendar year. These PADD averages are shown in Table 7.1.6-3.

Table 7.1.6-3
Sulfur Content of High Sulfur Diesel Fuel

PADD	Year	Volume (bbls/year)	Sulfur (ppm)	PADD Average
1	1996	7,170,833	3,482	2,925
	1997	13,250,000	2,601	
	1998	5,887,500	2,418	
	1999	4,137,500	3,257	
	2000	10,525,000	2,691	
	2001	4,437,500	3,061	
	2002	2,662,500	4,343	
2	1996	4,158,333	3,497	2,973
	1997	5,100,000	3,008	
	1998	2,775,000	2,241	
	1999	2,912,500	1,717	
	2000	10,412,500	2,939	
	2001	5,212,500	3,854	
	2002	1,000,000	1,620	
3	1996	2,420,833	4,539	3,776
	1997	4,500,000	3,945	
	1998	2,387,500	5,004	
	1999	3,000,000	4,177	
	2000	3,387,500	4,361	
	2001	1,775,000	4,298	
	2002	2,387,500	4,359	
4	1996	275,000	4,100	2,549
	1997	275,000	1,000	
	1998	275,000	3,400	
	1999	275,000	2,000	
	2000	275,000	2,600	
	2001	275,000	2,340	
	2002	275,000	2,400	
5	1996	2,050,000	3,076	2,566
	1997	3,550,000	2,268	
	1998	1,550,000	3,077	
	1999	1,550,000	2,065	
	2000	2,175,000 *	2,566 *	
	2001	2,175,000 *	2,566 *	
	2002	2,175,000 *	2,566 *	
U.S.	1996	16,075,000	3,623	3,030
	1997	26,675,000	2,710	
	1998	12,875,000	2,669	
	1999	11,875,000	2,818	
	2000	26,775,000	2,886	
	2001	14,375,000	3,440	
	2002	8,500,000	3,510	

* No data reported. Estimated from the average from 1996-1999.

We next calculated a national average sulfur content for each year. This was done by weighting the PADD average sulfur contents in each year by the volume of fuel represented by all the samples in that PADD. No data were reported for the Western Region for 2000, 2001 and 2002. Thus, we substituted the 1996-1999 average production volume and sulfur content for these missing years when calculating the national average for 1999-2002. These national averages are also shown in Table 7.1.6-3. It should be noted that these national average sulfur contents were not used in either the emissions nor cost analysis. The emission and cost analyses used the PADD average sulfur contents. However, we present them here for illustrative purposes and to simply the evaluation of the presence of any temporal trends in the sulfur content of high sulfur diesel fuel.

We examined the annual average sulfur contents for possible trends. However, as indicated by the national averages shown in Table 7.1.6-3, the sulfur content of high sulfur diesel fuel seems to vary randomly. Therefore, we average the data once more across calendar years, again using the fuel volumes represented by all the samples from each year. As shown in Table 7.1.6-3, this overall average sulfur content is 3030 ppm.

While the TRW reports indicate that the sulfur data was supplied by refiners, we assume that these sulfur levels are actually those existing at the point-of-use (i.e. retail). Thus, this average sulfur content of 3030 ppm is used in Chapter 3 to project emissions of sulfur dioxide and sulfate PM from the burning of NRLM fuel and heating oil. Because of the absence of a trend in the 1996-2002 data, we assume that these sulfur contents will not change in the future, absent NRLM fuel standards.

In order to project desulfurization costs, however, an estimate of the current sulfur content of NRLM fuel at the refinery is needed. As discussed in Sections 7.1.2 and 7.1.3, small volumes of jet fuel, highway diesel fuel and heavy gasoline become mixed with high sulfur distillate during pipeline shipment. These other fuels generally contain less sulfur than high sulfur diesel fuel, so the sulfur content of high sulfur diesel fuel actually decreases during shipment. In order to better estimate desulfurization costs, we estimated the sulfur content of high sulfur diesel fuel prior to this mixing during shipment.

The volumes of high sulfur distillate produced at refineries and the volume of material downgraded to high sulfur distillate is estimated in Sections 7.1.2 and 7.1.3 (see, for example, Tables 7.1.2-8 and 7.1.3-8). Here, we estimate the sulfur content of these various materials so that the combination matches the PADD average sulfur contents shown in Table 7.1.6-3.

Table 7.1.2-6 shows the types of downgrades and their volumes and destinations. This table shows that 1.75% of jet fuel demand, 2.2% of highway diesel fuel production, and a volume of heavy gasoline equivalent to 0.58% of jet fuel demand and 0.73% of highway diesel fuel production is shifted to high sulfur distillate during pipeline shipment. We estimate that jet fuel averages 550 ppm sulfur.[14] From the Final RIA for the highway diesel rule, highway diesel fuel averages 340 ppm sulfur. The sulfur level of today's gasoline, before the Tier 2 rule has been implemented, averages about 300 ppm. The vast majority of this sulfur is contained in the naphtha produced in the fluidized catalytic cracker (FCC naphtha). The sulfur content of FCC naphtha increases significantly with distillation temperature. Therefore, we estimate that the heaviest one-third of gasoline distilled into transmix contains essentially all the sulfur in the whole gasoline. Thus, we estimate the sulfur level of the heaviest one-third of gasoline to be about 900 ppm.

As described in Section 7.1.2, to simplify the analysis of downgrade distillate volume, we combined the jet fuel downgrade with the portion of the heavy gasoline downgrade which was dependent on jet fuel demand. Of this jet-based downgrade, jet fuel represents 75% (1.75/(1.75+0.58)) and heavy gasoline represents 25% (0.58/(1.75+0.58)). Weighting the sulfur content of jet fuel and heavy gasoline by these percentages produces an average sulfur content of 638 ppm.

Likewise, we combined the highway diesel fuel downgrade with the portion of the heavy gasoline downgrade which was dependent on highway diesel fuel production. Of this highway-based downgrade, highway diesel fuel represents 75% (2.2/(2.2+0.73)) and heavy gasoline represents 25% (0.73/(2.2+0.73)). Weighting the sulfur content of jet fuel and heavy gasoline by these percentages produces an average sulfur content of 480 ppm.[S]

Table 7.1.6-4 presents the levels of high sulfur distillate production and demand, as well as the volumes of downgraded material which are added to this fuel during distribution. All of these figures were taken directly from Table 7.1.2-8. Table 7.1.6-4 also shows the sulfur content of high sulfur diesel fuel at retail (from Table 7.1.6-3) and of the two types of downgrade, as discussed above. We determined the sulfur content of high sulfur distillate at the refinery which, when combined with the volumes and sulfur content of the two types of downgrade, matched the sulfur content from the TRW surveys. The sulfur content of high sulfur distillate at the refinery gate in each PADD are shown in Table 7.1.6-4. Because there are no product pipelines in Alaska and Hawaii, we assume that there is no downgrade in these areas. Also, because we assumed 100% spillover into the high sulfur distillate market in California, there is no high sulfur distillate in California pipelines to receive this downgrade. Distillate downgrade is assumed to be used directly as L&M fuel. Thus, we assume that the sulfur content of 2,570 ppm for high suflur distillate in PADD 5 applies at both retail and the refinery in Alaska, Hawaii, and California.

[S] The distillate sulfur contents presented at the end of this section for 1996-2006 assume that jet-based downgrade contains 700 ppm rather than 638 ppm and that highway-based downgrade contains 560 ppm rather than 480 ppm. These errors have a very small effect on the final sulfur content of high sulfur distillate fuels during these years. As the NRLM fuel program has no effect during these years, neither the costs nor benefits associated with this rule are affected.

Table 7.1.6-4
Sulfur Content of High Sulfur Diesel Fuel at Refineries in 2001

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5-O	AK, HI, CA
High Sulfur Distillate Fuel Volume						
Demand	10,955	4,562	4,407	408	497	486
Jet-Based Downgrade	95	80	123	12	51	0
Highway-Based Downgrade	327	387	202	64	68	0
Refinery Production	10,533	4,095	4,082	332	378	486
High Sulfur Distillate Sulfur Content (ppm)						
At Retail	2,930	2,970	3,780	2,550	2,570	2,570
Jet-Based Downgrade	638	638	638	638	638	638
Highway-Based Downgrade	480	480	480	480	480	480
Sulfur level of HS Dist Pool at Refineries	3,041	3,295	4,059	3,102	3,280	2,570

As can be seen, downgrade occurring in pipelines decreases the sulfur content of high sulfur distillate by as little as 111 ppm in PADD 1 and as much as 710 in PADD 5-O. The difference is due to the very small volume of downgrade relative to the demand for high sulfur distillate in PADD 1, with the opposite being true in PADD 5-O.

After completion of this analysis, we discovered that the TRW data represented sulfur levels at the refinery and not downstream. Thus, the TRW sulfur levels should have been used to estimate desulfurization costs in Section 7.2.2 and the adjustments shown in Table 7.1.6-4 should have been used to estimate lower sulfur levels downstream. The result of this error is an overestimation of the baseline sulfur content of high sulfur distillate by roughly 150 ppm on average. Given the limited data set and the resulting year-to-year variation, the resulting estimate is still well within the range of possible actual sulfur levels. This 150 ppm difference, if real, results in an overestimation of the cost to produce 500 ppm NRLM fuel of roughly 0.02 cent per gallon (i.e., roughly 1%) and an overestimation of the sulfur dioxide and sulfate PM emission reductions due to the 500 ppm NRLM fuel cap of roughly 4-5%.

The next step in this analysis is to project the sulfur content of the various distillate fuels during the various phases of the final NRLM fuel program, as well as under the two sensitivity cases. We assume that the sulfur content of NRLM fuel produced under 15 and 500 ppm caps will be the same as those we estimate for highway diesel fuel produced under the same standards. Thus, we assume that NRLM fuel produced to meet a 500 ppm cap will contain 340 ppm sulfur. We assume that NRLM fuel produced to meet a 15 ppm cap will contain 7 ppm sulfur at the refinery. However, as discussed in the Final RIA for the highway diesel rule, we assume that this fuel will contain 11 ppm at the time of final sale. This increase of 4 ppm is due to very small volumes of higher sulfur fuel being incorporated into batches of 15 ppm diesel fuel during shipment. This volume is by necessity very small compared to the volume of pipeline interface. Thus, this 4 ppm increase in 15 ppm fuel during shipment does not affect our estimation of the creation and disposition of downgrade created in the pipeline during shipment.

As just mentioned, highway fuel in the pipeline will contain between 7 and 11 ppm sulfur. We assume that the highway fuel contributing to interface contains 11 ppm sulfur. We assume that the sulfur content of jet fuel will remain 550 ppm in the future. Under the Tier 2 standards, gasoline will average 30 ppm sulfur. With this degree of sulfur control, essentially all the sulfur in gasoline will be in the heavy portion of FCC naphtha. Thus, we apply the same factor of 3 discussed above and estimate that the heaviest one-third of gasoline will contain 90 ppm sulfur.

Prior to the NRLM rule, the volume of jet-based downgrade stays the same as that shown in Table 7.1.6-4 (compare the jet-based downgrade in Table 7.1.2-6 (2001) to that in Table 7.1.3-6 (2014 prior to the NRLM rule)). Only the sulfur levels change. A 75%/25% weighting of the sulfur content of jet fuel (550 ppm) and heavy gasoline (90 ppm) produces an average sulfur content of 435 ppm.

As indicated in Table 7.1.3-6, the volume of highway-based downgrade increases significantly with the onset of the 15 ppm highway program, due to the need to make more protective interface cuts to maintain the quality of this fuel. As described in Table 7.1.3-6, 2.2% of highway diesel fuel supply will be cut directly into high sulfur distillate fuel. We assume that this highway fuel contains 11 ppm sulfur. Also, 2.2% of highway fuel supply plus a volume of heavy gasoline equivalent to 0.73% of highway fuel supply will be processed as transmix and added to the 500 ppm highway fuel supply. This downgrade will have an average sulfur content of 31 ppm (25% of 90 ppm plus 75% of 11 ppm).[T]

Under the NRLM fuel program, after 2007, some pipelines are projected to continue carrying heating oil, while others are expected to drop this fuel. For those pipelines still carrying heating oil (PADDs 1 and 3), the sulfur content of jet-based downgrade will continue to be 435 ppm, as described above. The sulfur content of the highway-based downgrade to high sulfur distillate and 500 ppm diesel fuel will continue to be 11 ppm and 31 ppm, respectively, as described above.[U]

[T] The distillate sulfur contents presented at the end of this section assume that jet-based downgrade in this time period contains 400 ppm rather than 435 ppm and that highway-based downgrade contains 35 ppm rather than 31 ppm. The net effect of these partially offsetting errors on the final sulfur content of high sulfur distillate fuels in the base case is very minor.

[U] TRW also surveys the quality of distillate fuel oil. These surveys which we received after completion of this analysis, show national average sulfur levels of roughly 2200 ppm, versus 3000 ppm for high sulfur diesel fuel. However, it is not clear how much distillate actually burned in heating oil uses is defined as heating oil at the refinery and how much is defined as diesel fuel. Thus, we chose not to use the heating oil survey results here. However, given that at least a portion of the heating oil market must meet state sulfur caps of 2000-4000 ppm, extrapolation of the diesel fuel survey results to heating oil probably over-estimates the sulfur content to some degree. Given that the sulfurous emission reductions from heating oil are only ancillary to the benefits of this rule, this likely small degree of overestimation is not critical. However, the heating oil related benefits are a large portion

For those pipelines not carrying heating oil, the nature of the downgrade and its disposition changes, as shown in Table 7.1.3-12. For these pipelines (all PADDs except 1 and 3), all of the jet-based downgrade is combined, as is the highway-based downgrade. The total jet-based downgrade consists of 3.5% of jet fuel demand and a volume of heavy gasoline equivalent to 0.58% of jet fuel demand. This is a 6:1 ratio of jet fuel to gasoline. With jet fuel at 550 ppm and heavy gasoline at 90 ppm, the average sulfur content of the jet-based downgrade is 485 ppm. Similarly, the total highway-based downgrade consists of 4.4% of highway fuel supply and a volume of heavy gasoline equivalent to 0.73% of highway fuel supply. This is a 6:1 ratio of highway fuel to gasoline. With highway fuel at 11 ppm and heavy gasoline at 90 ppm, the average sulfur content of the highway-based downgrade is 22 ppm.[V] While the disposition of this downgrade changes during the various phases of the NRLM fuel program, the sulfur content of these two types of downgrade remain the same.

7.1.4.2 Distillate Fuel Demand and Sulfur Content by Year

We present the final estimates of distillate fuel demand and sulfur content for each year from 1996-2040 in this section. We develop these estimates by combining:

1) The sulfur contents developed in Section 7.1.4.1 with
2) The sources of each distillate fuel's supply in 2014 developed in Sections 7.1.2 (Reference Case), 7.1.3 (after implementation of the final NRLM fuel program), and 7.1.4 (sensitivity cases), and
3) The growth in distillate fuel demand developed in Section 7.1.5.

We did this for the entire U.S. (50-state) and for 48 states (the U.S. minus the states of Alaska and Hawaii). The results are summarized in Tables 7.1.6-5 to 7.1.6-12. In all cases, we assume that a new sulfur standard becomes effective on June 1. Therefore, the average sulfur levels in any transition year is a 5:7 weighting of the previous year's sulfur level and the following year's sulfur level.

of the incremental benefits of associated with the 15 ppm cap for L&M fuel. Thus, we address the possibility of a lower sulfur content for heating oil in Section 8.3, where we evaluate the incremental cost effectiveness of the 15 ppm cap for L&M fuel.

[V] The distillate sulfur contents presented at the end of this section assume that jet-based downgrade in this time period contains 470 ppm rather than 485 ppm and that highway-based downgrade contains 25 ppm rather than 22 ppm. The net effect of these partially offsetting errors on the final sulfur content of high sulfur distillate fuels in the base case is minor.

Table 7.1.6-5 Annual Distillate Fuel Demand and Sulfur Content for the Reference Case; U.S. minus AK and HI (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,087	2,283	3,065	2,454	1,878	2,918	4,943	2,641	10,715	2,871
1997	9,376	2,283	2,971	2,454	1,863	2,918	4,834	2,641	10,654	2,871
1998	9,665	2,283	2,876	2,454	1,849	2,918	4,725	2,641	10,593	2,871
1999	9,945	2,283	2,782	2,454	1,834	2,918	4,616	2,641	10,532	2,871
2000	10,238	2,283	2,687	2,454	1,820	2,918	4,507	2,641	10,471	2,871
2001	10,530	2,283	2,772	2,454	1,805	2,918	4,577	2,637	10,411	2,871
2002	10,821	2,283	2,692	2,454	1,773	2,918	4,465	2,638	10,352	2,871
2003	11,112	2,283	2,722	2,454	1,795	2,918	4,517	2,638	10,292	2,871
2004	11,403	2,283	2,741	2,454	1,813	2,918	4,554	2,639	10,233	2,871
2005	11,694	2,283	2,762	2,454	1,825	2,918	4,587	2,639	10,174	2,871
2006	11,983	2,243	2,818	2,437	1,868	2,904	4,686	2,623	10,116	2,860
2007	12,272	2,214	2,868	2,424	1,895	2,893	4,763	2,611	10,058	2,853
2008	12,562	2,214	2,900	2,424	1,921	2,893	4,821	2,611	10,000	2,853
2009	12,851	2,214	2,939	2,424	1,944	2,893	4,883	2,611	9,943	2,853
2010	13,140	2,159	2,986	2,254	1,968	2,712	4,954	2,436	9,886	2,722
2011	13,430	2,120	3,043	2,133	1,997	2,583	5,039	2,312	9,829	2,628
2012	13,721	2,120	3,073	2,133	2,023	2,583	5,096	2,312	9,772	2,628
2013	14,012	2,120	3,097	2,133	2,041	2,583	5,138	2,312	9,716	2,628
2014	14,302	2,120	3,121	2,133	2,066	2,583	5,187	2,312	9,661	2,628
2015	14,593	2,120	3,148	2,133	2,089	2,583	5,236	2,313	9,605	2,628
2016	14,881	2,120	3,181	2,133	2,109	2,583	5,290	2,313	9,550	2,628
2017	15,169	2,120	3,210	2,133	2,132	2,583	5,342	2,313	9,495	2,628
2018	15,456	2,120	3,234	2,133	2,164	2,583	5,398	2,314	9,441	2,628
2019	15,744	2,120	3,266	2,133	2,201	2,583	5,466	2,314	9,386	2,628
2020	16,032	2,120	3,288	2,133	2,226	2,583	5,515	2,315	9,333	2,628
2021	16,319	2,120	3,305	2,133	2,254	2,583	5,559	2,316	9,279	2,628
2022	16,607	2,120	3,335	2,133	2,290	2,583	5,625	2,316	9,226	2,628
2023	16,895	2,120	3,364	2,133	2,316	2,583	5,680	2,317	9,173	2,628
2024	17,183	2,120	3,393	2,133	2,347	2,583	5,740	2,317	9,120	2,628
2025	17,470	2,120	3,426	2,133	2,374	2,583	5,800	2,317	9,068	2,628
2026	17,756	2,120	3,453	2,133	2,405	2,583	5,858	2,318	9,016	2,628
2027	18,042	2,120	3,481	2,133	2,436	2,583	5,917	2,319	8,964	2,628
2028	18,328	2,120	3,508	2,133	2,467	2,583	5,976	2,319	8,913	2,628
2029	18,613	2,120	3,536	2,133	2,499	2,583	6,035	2,320	8,861	2,628
2030	18,899	2,120	3,564	2,133	2,532	2,583	6,095	2,320	8,811	2,628
2031	19,185	2,120	3,591	2,133	2,564	2,583	6,155	2,321	8,760	2,628
2032	19,470	2,120	3,619	2,133	2,598	2,583	6,216	2,321	8,710	2,628
2033	19,756	2,120	3,646	2,133	2,631	2,583	6,277	2,322	8,660	2,628
2034	20,042	2,120	3,674	2,133	2,665	2,583	6,339	2,322	8,610	2,628
2035	20,328	2,120	3,701	2,133	2,700	2,583	6,401	2,323	8,561	2,624
2036	20,613	2,120	3,729	2,133	2,735	2,583	6,463	2,324	8,511	2,628
2037	20,899	2,120	3,756	2,133	2,770	2,583	6,526	2,324	8,463	2,628
2038	21,185	2,120	3,784	2,133	2,806	2,583	6,590	2,325	8,414	2,628
2039	21,470	2,120	3,811	2,133	2,842	2,583	6,653	2,325	8,366	2,628
2040	21,756	2,120	3,839	2,133	2,879	2,583	6,718	2,326	8,318	2,628

Table 7.1.6-6 Annual Distillate Fuel Demand and Sulfur Content: Final NRLM Rule: U.S. minus AK and HI (million gallons and ppm)					
	Nonroad	Locomotive	Marine	L&M	Heating Oil

Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,087	2,283	3,065	2,454	1,878	2,918	4,943	2,641	10,715	2,871
1997	9,376	2,283	2,971	2,454	1,863	2,918	4,834	2,641	10,654	2,871
1998	9,665	2,283	2,876	2,454	1,849	2,918	4,725	2,641	10,593	2,871
1999	9,945	2,283	2,782	2,454	1,834	2,918	4,616	2,641	10,532	2,871
2000	10,238	2,283	2,687	2,454	1,820	2,918	4,507	2,641	10,471	2,871
2001	10,530	2,283	2,772	2,454	1,805	2,918	4,577	2,637	10,411	2,871
2002	10,821	2,283	2,692	2,454	1,773	2,918	4,465	2,638	10,352	2,871
2003	11,112	2,283	2,722	2,454	1,795	2,918	4,517	2,638	10,292	2,871
2004	11,403	2,283	2,741	2,454	1,813	2,918	4,554	2,639	10,233	2,871
2005	11,694	2,283	2,762	2,454	1,825	2,918	4,587	2,639	10,174	2,871
2006	11,983	2,243	2,818	2,435	1,868	2,902	4,686	2,621	10,116	2,860
2007	12,272	1,127	2,868	1,225	1,895	1,469	4,763	1,321	10,058	2,667
2008	12,562	330	2,900	361	1,921	445	4,821	394	10,000	2,530
2009	12,851	330	2,939	361	1,944	445	4,883	394	9,943	2,530
2010	13,140	155	2,986	177	1,968	208	4,954	189	9,886	2,424
2011	13,430	30	3,043	45	1,997	39	5,039	43	9,829	2,349
2012	13,721	30	3,073	45	2,023	39	5,096	43	9,772	2,349
2013	14,012	19	3,097	45	2,041	39	5,138	43	9,716	2,349
2014	14,302	11	3,121	61	2,066	33	5,187	49	9,661	2,336
2015	14,593	11	3,148	72	2,089	28	5,236	54	9,605	2,327
2016	14,881	11	3,181	72	2,109	28	5,290	54	9,550	2,327
2017	15,169	11	3,210	72	2,132	28	5,342	54	9,495	2,327
2018	15,456	11	3,234	72	2,164	28	5,398	54	9,441	2,327
2019	15,744	11	3,266	72	2,201	28	5,466	54	9,386	2,327
2020	16,032	11	3,288	72	2,226	28	5,515	54	9,333	2,327
2021	16,319	11	3,305	72	2,254	28	5,559	54	9,279	2,327
2022	16,607	11	3,335	72	2,290	28	5,625	54	9,226	2,327
2023	16,895	11	3,364	72	2,316	28	5,680	54	9,173	2,327
2024	17,183	11	3,393	72	2,347	28	5,740	54	9,120	2,327
2025	17,470	11	3,426	72	2,374	28	5,800	54	9,068	2,327
2026	17,756	11	3,453	72	2,405	28	5,858	54	9,016	2,327
2027	18,042	11	3,481	72	2,436	28	5,917	54	8,964	2,327
2028	18,328	11	3,508	72	2,467	28	5,976	54	8,913	2,327
2029	18,613	11	3,536	72	2,499	28	6,035	54	8,861	2,327
2030	18,899	11	3,564	72	2,532	28	6,095	54	8,811	2,327
2031	19,185	11	3,591	72	2,564	28	6,155	54	8,760	2,327
2032	19,470	11	3,619	72	2,598	28	6,216	54	8,710	2,327
2033	19,756	11	3,646	72	2,631	28	6,277	54	8,660	2,327
2034	20,042	11	3,674	72	2,665	28	6,339	54	8,610	2,327
2035	20,328	11	3,701	72	2,700	28	6,401	54	8,561	2,327
2036	20,613	11	3,729	72	2,735	28	6,463	54	8,511	2,327
2037	20,899	11	3,756	72	2,770	28	6,526	54	8,463	2,327
2038	21,185	11	3,784	72	2,806	28	6,590	54	8,414	2,327
2039	21,470	11	3,811	72	2,842	28	6,653	54	8,366	2,327
2040	21,756	11	3,839	72	2,879	28	6,718	54	8,318	2,327

Table 7.1.6-7 Annual Distillate Fuel Demand and Sulfur Content: NRLM to 500 ppm in 2007, no 15 ppm Step; U.S. minus AK and HI (million gallons and ppm)

	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,087	2,283	3,065	2,454	1,878	2,918	4,943	2,641	10,715	2,871

1997	9,376	2,283	2,971	2,454	1,863	2,918	4,834	2,641	10,654	2,871
1998	9,665	2,283	2,876	2,454	1,849	2,918	4,725	2,641	10,593	2,871
1999	9,945	2,283	2,782	2,454	1,834	2,918	4,616	2,641	10,532	2,871
2000	10,238	2,283	2,687	2,454	1,820	2,918	4,507	2,641	10,471	2,871
2001	10,530	2,283	2,772	2,454	1,805	2,918	4,577	2,637	10,411	2,871
2002	10,821	2,283	2,692	2,454	1,773	2,918	4,465	2,638	10,352	2,871
2003	11,112	2,283	2,722	2,454	1,795	2,918	4,517	2,638	10,292	2,871
2004	11,403	2,283	2,741	2,454	1,813	2,918	4,554	2,639	10,233	2,871
2005	11,694	2,283	2,762	2,454	1,825	2,918	4,587	2,639	10,174	2,871
2006	11,983	2,242	2,818	2,435	1,868	2,902	4,686	2,621	10,116	2,860
2007	12,272	1,126	2,868	1,225	1,895	1,469	4,763	1,323	10,058	2,667
2008	12,562	330	2,900	361	1,921	445	4,821	394	10,000	2,530
2009	12,851	330	2,939	361	1,944	445	4,883	394	9,943	2,530
2010	13,140	276	2,986	293	1,968	348	4,954	315	9,886	2,526
2011	13,430	237	3,043	245	1,997	280	5,039	259	9,829	2,523
2012	13,721	237	3,073	245	2,023	280	5,096	259	9,772	2,523
2013	14,012	237	3,097	245	2,041	280	5,138	259	9,716	2,523
2014	14,302	237	3,121	245	2,066	280	5,187	259	9,661	2,523
2015	14,593	237	3,148	245	2,089	280	5,236	259	9,605	2,523
2016	14,881	237	3,181	245	2,109	280	5,290	259	9,550	2,523
2017	15,169	237	3,210	245	2,132	280	5,342	259	9,495	2,523
2018	15,456	237	3,234	245	2,164	280	5,398	259	9,441	2,523
2019	15,744	237	3,266	245	2,201	280	5,466	259	9,386	2,523
2020	16,032	237	3,288	245	2,226	280	5,515	259	9,333	2,523
2021	16,319	237	3,305	245	2,254	280	5,559	259	9,279	2,523
2022	16,607	237	3,335	245	2,290	280	5,625	259	9,226	2,523
2023	16,895	237	3,364	245	2,316	280	5,680	259	9,173	2,523
2024	17,183	237	3,393	245	2,347	280	5,740	259	9,120	2,523
2025	17,470	237	3,426	245	2,374	280	5,800	259	9,068	2,523
2026	17,756	237	3,453	245	2,405	280	5,858	259	9,016	2,523
2027	18,042	237	3,481	245	2,436	280	5,917	259	8,964	2,523
2028	18,328	237	3,508	245	2,467	280	5,976	259	8,913	2,523
2029	18,613	237	3,536	245	2,499	280	6,035	259	8,861	2,523
2030	18,899	237	3,564	245	2,532	280	6,095	259	8,811	2,523
2031	19,185	237	3,591	245	2,564	280	6,155	259	8,760	2,523
2032	19,470	237	3,619	245	2,598	280	6,216	259	8,710	2,523
2033	19,756	237	3,646	245	2,631	280	6,277	259	8,660	2,523
2034	20,042	237	3,674	245	2,665	280	6,339	259	8,610	2,523
2035	20,328	237	3,701	245	2,700	280	6,401	259	8,561	2,523
2036	20,613	237	3,729	245	2,735	280	6,463	259	8,511	2,523
2037	20,899	237	3,756	245	2,770	280	6,526	260	8,463	2,523
2038	21,185	237	3,784	245	2,806	280	6,590	260	8,414	2,523
2039	21,470	237	3,811	245	2,842	280	6,653	260	8,366	2,523
2040	21,756	237	3,839	245	2,879	280	6,718	260	8,318	2,523

Table 7.1.6-8 Proposed Rule Program: NRLM to 500 ppm in 2007, Nonroad Only to 15 ppm in 2010; U.S. minus AK and HI (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,087	2,283	3,065	2,454	1,878	2,918	4,943	2,641	10,715	2,871
1997	9,376	2,283	2,971	2,454	1,863	2,918	4,834	2,641	10,654	2,871
1998	9,665	2,283	2,876	2,454	1,849	2,918	4,725	2,641	10,593	2,871
1999	9,945	2,283	2,782	2,454	1,834	2,918	4,616	2,641	10,532	2,871
2000	10,238	2,283	2,687	2,454	1,820	2,918	4,507	2,641	10,471	2,871
2001	10,530	2,283	2,772	2,454	1,805	2,918	4,577	2,637	10,411	2,871
2002	10,821	2,283	2,692	2,454	1,773	2,918	4,465	2,638	10,352	2,871
2003	11,112	2,283	2,722	2,454	1,795	2,918	4,517	2,638	10,292	2,871
2004	11,403	2,283	2,741	2,454	1,813	2,918	4,554	2,639	10,233	2,871
2005	11,694	2,283	2,762	2,454	1,825	2,918	4,587	2,639	10,174	2,871
2006	11,983	2,242	2,818	2,437	1,868	2,904	4,686	2,623	10,116	2,860
2007	12,272	1,127	2,868	1,226	1,895	1,469	4,763	1,323	10,058	2,667
2008	12,562	330	2,900	361	1,921	445	4,821	394	10,000	2,530
2009	12,851	330	2,939	361	1,944	445	4,883	394	9,943	2,530
2010	13,140	152	2,986	293	1,968	343	4,954	313	9,886	2,526
2011	13,430	25	3,043	245	1,997	270	5,039	255	9,829	2,523
2012	13,721	25	3,073	245	2,023	270	5,096	255	9,772	2,523
2013	14,012	25	3,097	245	2,041	270	5,138	255	9,716	2,516
2014	14,302	17	3,121	200	2,066	259	5,187	224	9,661	2,512
2015	14,593	11	3,148	168	2,089	252	5,236	202	9,605	2,512
2016	14,881	11	3,181	168	2,109	252	5,290	202	9,550	2,512
2017	15,169	11	3,210	168	2,132	252	5,342	202	9,495	2,512
2018	15,456	11	3,234	168	2,164	252	5,398	202	9,441	2,512
2019	15,744	11	3,266	168	2,201	252	5,466	202	9,386	2,512
2020	16,032	11	3,288	168	2,226	252	5,515	202	9,333	2,512
2021	16,319	11	3,305	168	2,254	252	5,559	202	9,279	2,512
2022	16,607	11	3,335	168	2,290	252	5,625	202	9,226	2,512
2023	16,895	11	3,364	168	2,316	252	5,680	202	9,173	2,512
2024	17,183	11	3,393	168	2,347	252	5,740	202	9,120	2,512
2025	17,470	11	3,426	168	2,374	252	5,800	203	9,068	2,512
2026	17,756	11	3,453	168	2,405	252	5,858	203	9,016	2,512
2027	18,042	11	3,481	168	2,436	252	5,917	203	8,964	2,512
2028	18,328	11	3,508	168	2,467	252	5,976	203	8,913	2,512
2029	18,613	11	3,536	168	2,499	252	6,035	203	8,861	2,512
2030	18,899	11	3,564	168	2,532	252	6,095	203	8,811	2,512
2031	19,185	11	3,591	168	2,564	252	6,155	203	8,760	2,512
2032	19,470	11	3,619	168	2,598	252	6,216	203	8,710	2,512
2033	19,756	11	3,646	168	2,631	252	6,277	203	8,660	2,512
2034	20,042	11	3,674	168	2,665	252	6,339	203	8,610	2,512
2035	20,328	11	3,701	168	2,700	252	6,401	204	8,561	2,512
2036	20,613	11	3,729	168	2,735	252	6,463	204	8,511	2,512
2037	20,899	11	3,756	168	2,770	252	6,526	204	8,463	2,512
2038	21,185	11	3,784	168	2,806	252	6,590	204	8,414	2,512
2039	21,470	11	3,811	168	2,842	252	6,653	204	8,366	2,512
2040	21,756	11	3,839	168	2,879	252	6,718	204	8,318	2,512

Table 7.1.6-9 Annual Distillate Fuel Demand and Sulfur Content for the Reference Case; U.S. (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,136	2,284	3,072	2,455	1,960	2,902	5,032	2,640	11,071	2,859
1997	9,426	2,284	2,977	2,455	1,945	2,902	4,922	2,640	11,088	2,859
1998	9,717	2,284	2,882	2,455	1,929	2,902	4,811	2,640	10,945	2,859
1999	9,999	2,284	2,787	2,455	1,914	2,902	4,701	2,640	10,882	2,859
2000	10,293	2,284	2,691	2,455	1,899	2,902	4,590	2,640	10,819	2,859
2001	10,586	2,284	2,776	2,455	1,884	2,902	4,660	2,635	10,757	2,859
2002	10,879	2,284	2,696	2,455	1,850	2,902	4,546	2,637	10,695	2,859
2003	11,172	2,284	2,726	2,455	1,873	2,902	4,599	2,637	10,634	2,859
2004	11,465	2,284	2,745	2,455	1,892	2,902	4,637	2,637	10,573	2,859
2005	11,757	2,284	2,766	2,455	1,905	2,902	4,671	2,637	10,512	2,859
2006	12,048	2,244	2,823	2,437	1,949	2,888	4,772	2,621	10,452	2,849
2007	12,339	2,214	2,873	2,424	1,977	2,878	4,850	2,609	10,392	2,842
2008	12,629	2,214	2,904	2,424	2,005	2,878	4,909	2,609	10,332	2,842
2009	12,920	2,214	2,944	2,424	2,029	2,878	4,972	2,609	10,273	2,842
2010	13,210	2,160	2,990	2,255	2,054	2,705	5,044	2,438	10,214	2,712
2011	13,503	2,121	3,047	2,134	2,084	2,581	5,131	2,316	10,155	2,624
2012	13,795	2,121	3,077	2,134	2,111	2,581	5,188	2,316	10,097	2,624
2013	14,087	2,121	3,102	2,134	2,130	2,581	5,232	2,316	10,039	2,624
2014	14,379	2,121	3,126	2,134	2,156	2,581	5,282	2,316	9,982	2,624
2015	14,672	2,121	3,152	2,134	2,180	2,581	5,332	2,317	9,924	2,624
2016	14,961	2,121	3,186	2,134	2,200	2,581	5,386	2,317	9,867	2,624
2017	15,250	2,121	3,215	2,134	2,225	2,581	5,440	2,317	9,811	2,624
2018	15,539	2,121	3,239	2,134	2,258	2,581	5,497	2,318	9,754	2,624
2019	15,829	2,121	3,271	2,134	2,297	2,581	5,567	2,318	9,698	2,624
2020	16,118	2,121	3,293	2,134	2,323	2,581	5,617	2,319	9,643	2,624
2021	16,407	2,121	3,310	2,134	2,352	2,581	5,662	2,320	9,587	2,624
2022	16,986	2,121	3,339	2,134	2,390	2,581	5,730	2,320	9,532	2,624
2023	17,275	2,121	3,369	2,134	2,417	2,581	5,786	2,321	9,478	2,624
2024	17,564	2,121	3,398	2,134	2,449	2,581	5,847	2,321	9,423	2,624
2025	17,852	2,121	3,431	2,134	2,478	2,581	5,909	2,321	9,369	2,624
2026	18,139	2,121	3,458	2,134	2,510	2,581	5,968	2,322	9,315	2,624
2027	18,426	2,121	3,486	2,134	2,542	2,581	6,028	2,322	9,262	2,624
2028	18,714	2,121	3,514	2,134	2,575	2,581	6,089	2,323	9,209	2,624
2029	19,001	2,121	3,541	2,134	2,608	2,581	6,150	2,324	9,156	2,624
2030	19,575	2,121	3,569	2,134	2,642	2,581	6,211	2,324	9,103	2,624
2031	19,288	2,121	3,596	2,134	2,676	2,581	6,273	2,325	9,051	2,624
2032	19,575	2,121	3,624	2,134	2,711	2,581	6,335	2,325	8,999	2,624
2033	19,863	2,121	3,651	2,134	2,746	2,581	6,497	2,326	8,947	2,624
2034	20,150	2,121	3,679	2,134	2,781	2,581	6,460	2,326	8,896	2,624
2035	20,437	2,121	3,707	2,134	2,817	2,581	6,524	2,327	8,845	2,624
2036	20,724	2,121	3,734	2,134	2,854	2,581	6,588	2,328	8,794	2,624
2037	21,012	2,121	3,762	2,134	2,891	2,581	6,652	2,328	8,744	2,624
2038	21,299	2,121	3,789	2,134	2,928	2,581	6,717	2,329	8,694	2,624
2039	21,586	2,121	3,817	2,134	2,966	2,581	6,783	2,329	8,644	2,624
2040	21,873	2,121	3,844	2,134	3,004	2,581	6,849	2,330	8,594	2,624

Table 7.1.6-10 Annual Distillate Fuel Demand and Sulfur Content: Final NRLM Rule: U.S. (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,136	2,284	3,072	2,455	1,960	2,902	5,032	2,640	11,071	2,859
1997	9,426	2,284	2,977	2,455	1,945	2,902	4,922	2,640	11,088	2,859
1998	9,717	2,284	2,882	2,455	1,929	2,902	4,811	2,640	10,945	2,859
1999	9,999	2,284	2,787	2,455	1,914	2,902	4,701	2,640	10,882	2,859
2000	10,293	2,284	2,691	2,455	1,899	2,902	4,590	2,640	10,819	2,859
2001	10,586	2,284	2,776	2,455	1,884	2,902	4,660	2,635	10,757	2,859
2002	10,879	2,284	2,696	2,455	1,850	2,902	4,546	2,637	10,695	2,859
2003	11,172	2,284	2,726	2,455	1,873	2,902	4,599	2,637	10,634	2,859
2004	11,465	2,284	2,745	2,455	1,892	2,902	4,637	2,637	10,573	2,859
2005	11,757	2,284	2,766	2,455	1,905	2,902	4,671	2,637	10,512	2,859
2006	12,048	2,242	2,823	2,435	1,949	2,886	4,772	2,620	10,452	2,849
2007	12,339	1,130	2,873	1,228	1,977	1,500	4,850	1,340	10,392	2,662
2008	12,629	335	2,904	364	2,005	512	4,909	425	10,332	2,529
2009	12,920	335	2,944	364	2,029	512	4,972	425	10,273	2,529
2010	13,210	157	2,990	178	2,054	242	5,044	204	10,214	2,420
2011	13,503	30	3,047	46	2,084	49	5,131	47	10,155	2,343
2012	13,795	30	3,077	46	2,111	49	5,188	47	10,097	2,343
2013	14,087	30	3,102	46	2,130	49	5,232	47	10,039	2,343
2014	14,379	19	3,126	61	2,156	36	5,282	51	9,982	2,337
2015	14,672	11	3,152	71	2,180	27	5,332	53	9,924	2,333
2016	14,961	11	3,186	71	2,200	27	5,386	53	9,867	2,333
2017	15,250	11	3,215	71	2,225	27	5,440	53	9,811	2,333
2018	15,539	11	3,239	71	2,258	27	5,497	53	9,754	2,333
2019	15,829	11	3,271	71	2,297	27	5,567	53	9,698	2,333
2020	16,118	11	3,293	71	2,323	27	5,617	53	9,643	2,333
2021	16,407	11	3,310	71	2,352	27	5,662	53	9,587	2,333
2022	16,697	11	3,339	71	2,390	27	5,730	53	9,532	2,333
2023	16,986	11	3,369	71	2,417	27	5,786	53	9,478	2,333
2024	17,275	11	3,398	71	2,449	27	5,847	53	9,423	2,333
2025	17,564	11	3,431	71	2,478	27	5,909	53	9,369	2,333
2026	17,852	11	3,458	71	2,510	27	5,968	53	9,315	2,333
2027	18,139	11	3,486	71	2,542	27	6,028	53	9,262	2,333
2028	18,426	11	3,514	71	2,575	27	6,089	53	9,209	2,333
2029	18,714	11	3,541	71	2,608	27	6,150	53	9,156	2,333
2030	19,001	11	3,569	71	2,642	27	6,211	53	9,103	2,333
2031	19,288	11	3,596	71	2,676	27	6,273	53	9,051	2,333
2032	19,575	11	3,624	71	2,711	27	6,335	53	8,999	2,333
2033	19,863	11	3,651	71	2,746	27	6,497	53	8,947	2,333
2034	20,150	11	3,679	71	2,781	27	6,460	52	8,896	2,333
2035	20,437	11	3,707	71	2,817	27	6,524	52	8,845	2,333
2036	20,724	11	3,734	71	2,854	27	6,588	52	8,794	2,333
2037	21,012	11	3,762	71	2,891	27	6,652	52	8,744	2,333
2038	21,299	11	3,789	71	2,928	27	6,717	52	8,694	2,333
2039	21,586	11	3,817	71	2,966	27	6,783	52	8,644	2,333
2040	21,873	11	3,844	71	3,004	27	6,849	52	8,594	2,333

Table 7.1.6-11 Annual Distillate Fuel Demand and Sulfur Content: NRLM to 500 ppm in 2007, no 15 ppm Step; U.S. (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,136	2,284	3,072	2,455	1,960	2,902	5,032	2,640	11,071	2,859
1997	9,426	2,284	2,977	2,455	1,945	2,902	4,922	2,640	11,088	2,859
1998	9,717	2,284	2,882	2,455	1,929	2,902	4,811	2,640	10,945	2,859
1999	9,999	2,284	2,787	2,455	1,914	2,902	4,701	2,640	10,882	2,859
2000	10,293	2,284	2,691	2,455	1,899	2,902	4,590	2,640	10,819	2,859
2001	10,586	2,284	2,776	2,455	1,884	2,902	4,660	2,635	10,757	2,859
2002	10,879	2,284	2,696	2,455	1,850	2,902	4,546	2,637	10,695	2,859
2003	11,172	2,284	2,726	2,455	1,873	2,902	4,599	2,637	10,634	2,859
2004	11,465	2,284	2,745	2,455	1,892	2,906	4,637	2,637	10,573	2,859
2005	11,757	2,284	2,766	2,455	1,905	2,906	4,671	2,637	10,512	2,859
2006	12,048	2,242	2,823	2,435	1,949	2,886	4,772	2,620	10,452	2,849
2007	12,339	1,130	2,873	1,227	1,977	1,502	4,850	1,340	10,392	2,662
2008	12,629	335	2,904	364	2,005	512	4,909	425	10,332	2,529
2009	12,920	335	2,944	364	2,029	512	4,972	425	10,273	2,529
2010	13,210	278	2,990	295	2,054	378	5,044	329	10,214	2,525
2011	13,503	237	3,047	245	2,084	282	5,131	260	10,155	2,522
2012	13,795	237	3,077	245	2,111	282	5,188	260	10,097	2,522
2013	14,087	237	3,102	245	2,130	282	5,232	260	10,039	2,522
2014	14,379	237	3,126	245	2,156	282	5,282	260	9,982	2,522
2015	14,672	237	3,152	245	2,180	282	5,332	260	9,924	2,522
2016	14,961	237	3,186	245	2,200	282	5,386	260	9,867	2,522
2017	15,250	237	3,215	245	2,225	282	5,440	260	9,811	2,522
2018	15,539	237	3,239	245	2,258	282	5,497	260	9,754	2,522
2019	15,829	237	3,271	245	2,297	282	5,567	260	9,698	2,522
2020	16,118	237	3,293	245	2,323	282	5,617	260	9,643	2,522
2021	16,407	237	3,310	245	2,352	282	5,662	260	9,587	2,522
2022	16,697	237	3,339	245	2,390	282	5,730	260	9,532	2,522
2023	16,986	237	3,369	245	2,417	282	5,786	260	9,478	2,522
2024	17,275	237	3,398	245	2,449	282	5,847	260	9,423	2,522
2025	17,564	237	3,431	245	2,478	282	5,909	260	9,369	2,522
2026	17,852	237	3,458	245	2,510	282	5,968	260	9,315	2,522
2027	18,139	237	3,486	245	2,542	282	6,028	261	9,262	2,522
2028	18,426	237	3,514	245	2,575	282	6,089	261	9,209	2,522
2029	18,714	237	3,541	245	2,608	282	6,150	261	9,156	2,522
2030	19,001	237	3,569	245	2,642	282	6,211	261	9,103	2,522
2031	19,288	237	3,596	245	2,676	282	6,273	261	9,051	2,522
2032	19,575	237	3,624	245	2,711	282	6,335	261	8,999	2,522
2033	19,863	237	3,651	245	2,746	282	6,497	261	8,947	2,522
2034	20,150	237	3,679	245	2,781	282	6,460	261	8,896	2,522
2035	20,437	237	3,707	245	2,817	282	6,524	261	8,845	2,522
2036	20,724	237	3,734	245	2,854	282	6,588	261	8,794	2,522
2037	21,012	237	3,762	245	2,891	282	6,652	261	8,744	2,522
2038	21,299	237	3,789	245	2,928	282	6,717	261	8,694	2,522
2039	21,586	237	3,817	245	2,966	282	6,783	261	8,644	2,522
2040	21,873	237	3,844	245	3,004	282	6,849	261	8,594	2,522

Table 7.1.6-12 Annual Distillate Fuel Demand and Sulfur Content: Proposed Rule Program: 500 ppm NRLM ppm in 2007, 15 ppm Nonroad Only in 2010; U.S. (million gallons and ppm)										
	Nonroad		Locomotive		Marine		L&M		Heating Oil	
Year	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur	Demand	Sulfur
1996	9,136	2,284	3,072	2,455	1,960	2,902	5,032	2,640	11,071	2,859
1997	9,426	2,284	2,977	2,455	1,945	2,902	4,922	2,640	11,088	2,859
1998	9,717	2,284	2,882	2,455	1,929	2,902	4,811	2,640	10,945	2,859
1999	9,999	2,284	2,787	2,455	1,914	2,902	4,701	2,640	10,882	2,859
2000	10,293	2,284	2,691	2,455	1,899	2,902	4,590	2,640	10,819	2,859
2001	10,586	2,284	2,776	2,455	1,884	2,902	4,660	2,635	10,757	2,859
2002	10,879	2,284	2,696	2,455	1,850	2,902	4,546	2,637	10,695	2,859
2003	11,172	2,284	2,726	2,455	1,873	2,902	4,599	2,637	10,634	2,859
2004	11,465	2,284	2,745	2,455	1,892	2,902	4,637	2,637	10,573	2,859
2005	11,757	2,284	2,766	2,455	1,905	2,902	4,671	2,637	10,512	2,859
2006	12,048	2,242	2,823	2,435	1,949	2,888	4,772	2,621	10,452	2,849
2007	12,339	1,130	2,873	1,228	1,977	1,502	4,850	1,340	10,392	2,662
2008	12,629	335	2,904	364	2,005	512	4,909	425	10,332	2,529
2009	12,920	335	2,944	364	2,029	512	4,972	425	10,273	2,529
2010	13,210	163	2,990	295	2,054	373	5,044	326	10,214	2,525
2011	13,503	40	3,047	245	2,084	273	5,131	256	10,155	2,522
2012	13,795	40	3,077	245	2,111	273	5,188	256	10,097	2,522
2013	14,087	40	3,102	245	2,130	273	5,232	256	10,039	2,522
2014	14,379	23	3,126	200	2,156	255	5,282	223	9,982	2,516
2015	14,672	11	3,152	169	2,180	242	5,332	199	9,924	2,511
2016	14,961	11	3,186	169	2,200	242	5,386	199	9,867	2,511
2017	15,250	11	3,215	169	2,225	242	5,440	199	9,811	2,511
2018	15,539	11	3,239	169	2,258	242	5,497	199	9,754	2,511
2019	15,829	11	3,271	169	2,297	242	5,567	199	9,698	2,511
2020	16,118	11	3,293	169	2,323	242	5,617	199	9,643	2,511
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2022	16,697	11	3,339	169	2,390	242	5,730	199	9,532	2,511
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2033	19,863	11	3,651	169	2,746	242	6,497	200	8,947	2,511
2034	20,150	11	3,679	169	2,781	242	6,460	200	8,896	2,511
2035	20,437	11	3,707	169	2,817	242	6,524	200	8,845	2,511
2036	20,724	11	3,734	169	2,854	242	6,588	200	8,794	2,511
2037	21,012	11	3,762	169	2,891	242	6,652	200	8,744	2,511
2038	21,299	11	3,789	169	2,928	242	6,717	201	8,694	2,511
2039	21,586	11	3,817	169	2,966	242	6,783	201	8,644	2,511
2040	21,873	11	3,844	169	3,004	242	6,849	201	8,594	2,511

7.2 Refining Costs

The most significant cost involved in providing diesel fuel meeting more stringent sulfur standards is the cost of removing the sulfur at the refinery. In this section, we describe the methodology used and present the estimated costs for refiners to:

- comply with the 2007 Nonroad, Locomotive, and Marine (NRLM) 500 ppm diesel fuel sulfur standards and the 15 ppm nonroad diesel fuel standard in 2010 and the 15 ppm L&M standard in 2012,
- comply with other NRLM diesel fuel sulfur sensitivity cases considered, and
- comply with the 2006 sulfur standards already adopted for highway diesel fuel (an update of a previous cost analysis).

Finally, we compare our estimated costs with those developed by Mathpro (for the Engine Manufacturers Association) and Baker and O'Brien (for the American Petroleum Institute).

7.2.1 Methodology

7.2.1.1 Overview

This section describes the methodology used to estimate the refining cost of reducing diesel fuel sulfur content. Costs are estimated based on two distinct desulfurization technologies: conventional hydrotreating and the Process Dynamics IsoTherming process. Conventional hydrotreating cost estimates were based on information from two vendors, while the cost estimates for the more advanced process was made from information provided by the respective vendor. For both technologies, costs are estimated for each U.S. refinery currently producing distillate fuel. Conventional hydrotreating technology was projected to be used to desulfurize distillate to meet a 500 ppm sulfur cap. A mix comprised of advanced desulfurization technology with some conventional hydrotreating technology was projected to be used to meet the 15 ppm sulfur cap. This mix of technology varied depending on the timing of the 15 ppm sulfur standard. To meet the 500 ppm and 15 ppm sulfur standards, refiners are expected to desulfurize to 340 ppm and 7 ppm, respectively.

Refining costs were developed for revamping existing hydrotreaters that produce low-sulfur diesel fuel, as well as new, grass roots desulfurization units. The lower revamped costs were primarily used when streams or parts of streams were already desulfurized (i.e., highway), while the grassroots costs applied normally for untreated streams (mostly nonroad). In both cases, costs were developed for our refinery cost model and used to estimate the desulfurization cost for each refinery in the United States producing distillate fuel in 2001. These refinery-specific costs consider the volume of distillate fuel produced, the composition of this distillate fuel, and the location of the refinery (e.g., Gulf Coast, Rocky Mountain region, etc.). The estimated composition of each refinery's distillate included the fraction of hydrotreated and nonhydrotreated straight-run distillate, light cycle oil (LCO), other cracked stocks (coker, visbreaker, thermal cracked) and hydrocracked distillate, and the cost to desulfurize each of those stocks. The cost information provided by the various vendors was used to develop the desulfurization cost for each blendstock; however, when lacking, engineering judgment was used to develop the needed specific cost estimate. The average desulfurization cost for each refinery was based on the volume-weighted average of desulfurizing each of those blendstocks. The production volumes used were those indicative of 2014, a midyear of the estimated 15 year project life of the year 2007 capital investments by the refining industry.

7.2.1.2 Basic Cost Inputs for Specific Desulfurization Technologies

To obtain a comprehensive basis for estimating the cost of desufurizing diesel fuel, over the past few years we have held meetings with a large number of vendors of desulfurization technologies. These firms include: Criterion Catalyst, UOP, Akzo Nobel, Haldor Topsoe, and Process Dynamics. We have also met with numerous refiners of diesel fuel considering the use of these technologies and reviewed the literature on this subject. The information and estimates described below represent the culmination of these efforts. See Chapter 5 of the RIA for a more complete discussion of conventional hydrotreating and Process Dynamics Isotherming, as well as other desulfurization technologies evaluated in the course of this rulemaking.

The information used in our refinery cost model for estimating the cost of meeting 500 and 15 ppm sulfur caps using conventional hydrotreating is presented first. The cost methodology for conventional hydrotreating was developed for the HD2007 rulemaking for highway diesel fuel. Only the final process-design parameters are presented here. For a complete description of the methodology used to develop the cost estimates for conventional hydrotreating, consult Chapter 5 of the HD2007 Regulatory Impact Analysis.[15] The few variations from the HD2007 methodology are described below.

Next we present the methodology and resulting cost information used for developing the refinery costs for the Process Dynamics IsoTherming processs. In this case, we begin by presenting the estimates of the process-design parameters provided by the developers of this process. These projections are then evaluated to produce sets of process-design parameters that can be used to estimate the cost of meeting 500 ppm and 15 ppm NRLM diesel fuel standards for each domestic refiner. The resulting refining cost projections are presented and discussed in Section 7.2.2.

7.2.1.2.1 Conventional Desulfurization Technology

The cost of desulfurizing diesel fuel includes the capital cost related to designing and constructing the desulfurization unit, as well as the cost of operating the unit. We were able to obtain fairly complete sets of such process-design parameters from two out of the five or six licensors of conventional desulfurization technologies[16,17,18]. These designs addressed the production of 15 ppm diesel fuel by retrofitting existing hydrotreaters originally designed to produce 500 ppm diesel fuel, as well as building new, grass roots units. These two sets of process-design parameters were also used to estimate the cost of hydrotreating high-sulfur diesel fuel down to 500 ppm.

In addition to the information obtained from these two vendors, we reviewed similar information submitted to the National Petroleum Council (NPC) by Akzo Nobel, Criterion, Haldor Topsoe, UOP and IFP for its study of diesel fuel desulfurization costs and discussed them with the vendors.[19] These submissions were generally not as comprehensive as those provided by the two vendors mentioned above. In all cases, these submissions corroborated the costs from the two vendors.

All the vendors identified operating pressures sufficient to produce fuel meeting a 15 ppm sulfur cap under 900 psi. Most of the vendors projected that 650 psi is sufficient, while others indicated that pressures well below 1000 psi are sufficient. A contractor for API indicated that they believe a 850 psi unit is enough to meet a 15 ppm cap, though lower-pressure units would not be sufficient. We therefore based our estimate of capital cost on two different vendor submissions based on units operating at 650 and 900 psi.

Based on the information obtained from the two vendors of conventional hydrotreating technologies, as well as that obtained from Process Dynamics, we project that refiners will use conventional hydrotreating to produce NRLM diesel fuel meeting the 500 ppm standard in 2007. This unit would include heat exchangers, a fired pre-heater, a reactor, a hydrogen compressor and a make up compressor, and both high-pressure and low-pressure strippers. The refinery would also need a source of new hydrogen, an amine scrubber and a sulfur plant. Most refineries already have sources of hydrogen, an amine scrubber and a sulfur plant. However, considering the hydrogen demand for complying with Tier 2 sulfur standards for gasoline and the 15 ppm cap on highway diesel sulfur, no residual refinery production hydrogen is expected to exist. We therefore project that any new hydrogen demand will likely be produced from the addition of a new steam reforming hydrogen plant using natural gas as the feedstock, either on-site or by a third party. Likewise, a refinery's amine scrubber and sulfur plant would need modest expansion.

Producing diesel fuel meeting a 15 ppm standard generally requires much greater reactor volume and a larger hydrogen capacity, both in terms of compressor capacity and ability to introduce this hydrogen into the reactor, than are required to meet a 500 ppm cap. Since the 15 ppm sulfur cap for nonroad diesel fuel follows the 500 ppm NRLM sulfur cap by only three years and L&M by 5 years, we project that refiners will design any new hydrotreaters built for 2007 to be easily retrofitted with additional equipment, such as a second reactor, a hydrogen compressor, a recycle scrubber, an inter-stage stripper and other associated process hardware. The technical approach described by each vendor to achieve a 15 ppm sulfur cap (average level of 7-8 ppm) is summarized in Table 7.2.1-1.

Table 7.2.1-1
Modifications Necessary to Reduce 500 ppm Sulfur Levels to 15 ppm

Diesel Fuel Sulfur Level	Vendor A	Vendor B
7-8 ppm (15 ppm cap)	Change to a more active catalyst Install recycle gas scrubber Modify compressor Install a second reactor, high pressure (900 psi) Use existing hot oil separator for inter-stage stripper	Change to a more active catalyst Install a recycle gas scrubber Install a second reactor (650 psi) Install a color reactor Install an interstage stripper

It is important to note that back when the highway rulemaking was being promulgated, the vendors of conventional hydrotreating technology believed that a high pressure interstage stripper was needed for each hydrotreating unit to meet the 15 ppm sulfur cap standard, and included the costs for such a unit in their cost estimates. However, since that time the vendors are no longer recommending that the 15 ppm hydrotreaters include such a stage in the desulfurization process thus negating the need for the associated piece of capital. Our costs estimates are nevertheless still based on the vendor capital cost estimates which include the interstage stripper. Thus, the capital costs on which this rulemaking is based are, with respect to this single factor, somewhat conservative compared to the costs which refiners would likely incur to comply with the 15 ppm sulfur standard.

The vendors assumed that the existing highway desulfurization unit in place could be utilized (revamped) to comply with the 15 ppm sulfur standards. This includes hydrotreater sub-units necessary for desulfurization. Revamping the highway unit saves on both capital and operating costs for a two-stage revamp compared with whole new grassroots unit. These sub-units include heat exchangers, a heater, a reactor filled with catalyst, two or more vessels used for separating hydrogen and any light ends produced by cracking during the desulfurization process, a compressor, and sometimes a hydrogen recycle gas scrubber. The desulfurization subunits listed here are discussed in detail in Chapter 5.

To estimate the cost of meeting the NRLM diesel fuel sulfur standards, it was necessary to evaluate three situations refiners may face: (1) producing NRLM diesel fuel meeting a 15 ppm cap from diesel fuel already being hydrotreated to meet a 500 ppm cap (i.e., a highway revamp), (2) producing NRLM diesel fuel meeting a 15 ppm cap from high-sulfur distillate (i.e., grass roots 15 ppm hydrotreater), and (3) producing 15 ppm NRLM diesel fuel meeting a 500 ppm cap by replacing the existing hydrotreater with a grass roots 15 ppm hydrotreater. Sets of process-design parameters for the first two of these desulfurization configurations were developed for the HD2007 rule and summarized in the Regulatory Impact Analysis.[20] As discussed above, only the results of the previous derivations are presented below. The third configuration was not addressed for the highway diesel fuel rule, as highway diesel fuel was already meeting a 500 ppm cap. The section that develops the process-design parameters for this third configuration includes a short description of the methodology used in its development, as it is very similar to those used to develop the first two sets of process-design parameters.

One straightforward adjustment was made to all the capital costs developed for the HD2007 rule. The capital costs developed for that rule were in terms of 1999 dollars. These costs were updated to represent 2002 dollars by increasing them by 2.5 percent to reflect inflation in construction costs occurring between 1999 and 2002.[21]

7.2.1.2.1.1 Revamping to Process 500 ppm Diesel Fuel to Meet a 15 ppm Cap

The process-design projections developed in this section apply to a revamp of an existing desulfurization unit with additional hardware to enable the combined older and new unit to meet a 15 ppm sulfur cap. The portion of these projections that apply to operating costs are also relevant if a refiner decides to replace an existing diesel fuel desulfurization unit with a new grassroots unit. In this case, the entire capital cost of the grass roots unit is incurred. However, the incremental operating costs would be those of the new grass roots unit, less those of the existing hydrotreater (which are developed in this section).

The process-design parameters shown below were taken directly from those shown in the HD2007 Regulatory Impact Analysis, with two adjustments. The first adjustment relates to the amount of desulfurization required from the current low sulfur diesel pool, while the second adjustment relates to the amount of fuel gas consumed in the process.

Diesel fuel complying with the current 500 ppm sulfur standard typically contains 340 ppm sulfur. We expect refiners complying with the 500 ppm NRLM diesel fuel sulfur cap also to desulfurize down to roughly 340 ppm sulfur. Thus, in revamping an existing 500 ppm hydrotreater to comply with a 15 ppm cap, refiners will have to desulfurize from about 340 ppm down to 7 ppm. This is analogous to what we assumed in the analysis for the HD2007 rule. After the highway diesel fuel rule was finalized, however, it became evident that the vendor projections assumed a starting sulfur level of 500 ppm and not 340 ppm. Thus, the vendor projections assumed more desulfurization would be needed than is the case here. Based on a curve of hydrogen consumption versus initial and final sulfur level developed in the Regulatory Impact Analysis supporting the proposed HD2007 program, reducing the initial sulfur level from 500 ppm to 340 ppm reduces hydrogen consumption by 3.5 percent.[22] We assumed that all cost-related parameters (capital cost,[W] catalyst cost, yield losses, and utilities) will be reduced by the same 3.5 percent.

For the second adjustment, the fuel gas rates were adjusted to account for the heat produced by the saturation of the aromatic compounds that occurs during desulfurization. In the Draft RIA for the NPRM, we presumed that the highly aromatic blendstocks, which are LCO and coker, would consume more fuel gas than straight run distillate, which has much less aromatics. However, because the aromatic compounds are exothermic in the hydrotreating reactor, they actually contribute some heat which lowers the heat load compared to straight run distillate. Furthermore, when updating the fuel gas consumption values, we found and corrected an error in

[W] Capital costs are also affected, as a higher starting sulfur level requires a larger reactor to provide a greater residence time to remove the sulfur and a larger compressor for the greater volume of hydrogen which must be fed to the reactor.

our interpretation of fuel gas consumption information from one of the two vendors which provided us with the unit operations information for their diesel fuel desulfurization technology. The error was that we had interpreted that vendor's information to read as thousands of British thermal units (BTUs) per day instead of millions of BTUs per day.

Some of the information from one of the two vendors (which was referred to as Vendor A in the 2007 Highway Final Rule) was used to estimate the relative heat demand for the two mixed distillate streams. The heat demand information was presented as million BTU per hour a 25,000 bbl/day grassroots unit producing 15 ppm diesel. We converted this estimate to BTU/bbl and summarized the values in Table 7.2.1-2.

Table 7.2.1-2
Fuel Gas Demand for a 15 ppm Grassroots Unit (BTU/bbl)

67% cracked stocks, 33% SR	1100
20% cracked stocks, 80% SR	1480

The above table shows a 380 btu/bbl difference in heat consumption between the two feeds for a grassroots unit. Based on this information, we were able to estimate that cracked stocks require only 56 percent of the heat input of straight run stocks. The fuel gas consumption estimate for the cracked stocks (LCO and coker light gas oil) is 920 btu/bbl while the fuel gas consumption for straight run gas oil is 1640 btu/bbl. Since this is the heat consumption for only Vendor A, it was necessary to merge the fuel gas consumption information from Vendor B. Vendor B reported fuel gas consumption of 16,000 btu/bbl. This value is much higher probably because it incorporates the fuel gas used to generate steam for pumping. Because both vendors were providing cost estimates on the same feeds (69 percent straight run 31 percent cracked stocks) to achieve the same desulfurization target, it is likely that both were assuming similar levels of aromatics saturation, thus we assume that both vendors would estimate a similar absolute difference in heat consumption between the different blendstocks. To estimate an average heat consumption representing the heat consumption estimates from both vendors, we averaged the average heat for the two vendors (assuming an average of 1320 btu/bbl for Vendor A) resulting in an average heat consumption of 8660 btu/bbl. Assuming that the heat consumed by each blendstock maintains the same differential as that calculated based on Vendor A's information alone, the heat consumed is 8880 btu/bbl for straight run and 8160 for cracked stocks which maintains the same 720 btu/bbl difference from above.

Since we need to estimate the incremental fuel gas demand for a unit treating diesel fuel meeting a 500 ppm cap standard to comply with a 15 ppm cap standard for this section, the fuel consumption information from Vendors A and B was evaluated for this sulfur reduction increment. Both vendors show essentially zero fuel gas consumption for this interval, yet aromatics are still being saturated similar to about half the increment of going from untreated to 15 ppm sulfur. Thus, half the difference in fuel gas consumed for cracked stocks and straight run was assumed for this interval with a typical blend of diesel fuel (69 percent straight run and 31 percent cracked stocks) having a zero net fuel gas consumption. Thus, cracked stocks are estimated to require -250 btu/bbl of fuel gas and straight run is estimated to require 110 btu/bbl of fuel gas for a difference of 360 scf/bbl or half of that for a grassroots unit.

Table 7.2.1-3 presents the process-design parameters for desulfurizing 500 ppm sulfur diesel fuel to meet a 15 ppm standard.

Table 7.2.1-3
Process Projections for Revamping an Existing Diesel Fuel Hydrotreater Desulfurizing Diesel Fuel Blendstocks from 500 ppm Cap to 15 ppm Cap

	Straight-Run	Other Cracked Stocks	Light Cycle Oil
Capacity (BPSD)	25,000	25,000	25,000
Capital Cost (ISBL) ($million)	16	19	22
Liquid Hour Space Velocity (hr^{-1})	1.25	0.7	0.6
Hydrogen Consumption (scf/bbl)	96	230	375
Electricity (kW-hr/bbl)	0.4	0.7	0.8
HP Steam (lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	110	-250	-250
Catalyst Cost ($/BPSD)	0.2	0.4	0.5
Yield Loss (wt%)			
Diesel	1.0	1.9	2.1
Naphtha	-0.7	-1.3	-1.4
LPG	-0.04	-0.07	-0.08
Fuel Gas	-0.04	-0.11	-0.13

7.2.1.2.1.2 Process-Design Projections for a Grassroots Unit Producing 15 ppm Fuel

The process-design parameters presented in this section were taken directly from those derived in the HD2007 Regulatory Impact Analysis. These costs apply primarily to refineries currently producing only, or predominantly, high-sulfur diesel fuel. In addition, the capital cost portion of these costs apply to a refinery replacing an existing hydrotreater with a grassroots unit instead of revamping their existing hydrotreater. In this case, these refiners would incur the capital costs outlined here, but their operating costs would be based on a revamp, as described above. Most refineries currently producing high-sulfur distillate fuel also produce some highway diesel fuel. In this case, we project costs reflecting those of a revamp and a grass roots unit. The methodology for this merging of the two costs is described in Section 7.2.1.5 below.

Table 7.2.1-4 presents the process-design parameters for desulfurizing high-sulfur distillate fuel to meet a 15 ppm standard in a grassroots unit.

Table 7.2.1-4
Process Projections for Installing a New Grassroots Unit for Desulfurizing Untreated Distillate Fuel Blendstocks to Meet a 15 ppm Standard

	Straight-Run	Other Cracked Stocks	Light Cycle Oil
Capacity BPSD (bbl/day)	25,000	25,000	25,000
Capital Cost (ISBL) (MM$)	32	38	43
Liquid Hour Space Velocity (Hr^{-1})	0.8	0.5	0.4
Hydrogen Consumption (SCF/bbl)	240	850	1100
Electricity (KwH/bbl)	0.6	1.1	1.2
HP Steam (Lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	8880	8160	8160
Catalyst Cost ($/BPSD)	0.3	0.6	0.8
Yield Loss (%)			
Diesel	1.5	2.9	3.3
Naphtha	-1.1	-2.0	-2.3
LPG	-0.06	-0.11	-0.12
Fuel Gas	-0.06	-0.17	-0.20

Unlike processing highway diesel fuel, which is assumed to contain 340 ppm sulfur, the sulfur content of high-sulfur distillate fuel can vary dramatically from refinery to refinery and region to region. To account for varying starting sulfur levels, an adjustment in hydrogen consumption. The basis for the amount of sulfur needing to be removed is that the starting feed, comprised of 69 percent straight-run, 23 percent LCO and 8 percent cracked stocks, contains 9000 ppm sulfur (0.9 weight percent). However, as described below in Section 7.2.1.3, the average concentration of sulfur in the overall distillate pool, and especially the untreated part of the pool, varies by PADD. After estimating this sulfur level, we adjusted the hydrogen consumption for this varying sulfur level. (According to Vendor B, removing sulfur from diesel fuel consumes 125 scf/bbl for each weight percent of sulfur removed.[23]) We did not adjust the hydrogen consumption for the other qualities, mono- and poly-aromatics and olefins, but assumed that the hydrogen consumption from saturating olefins and aromatics, or from breaking aromatic rings would depend more on whether the feedstock had been previously hydrotreated or not, and less on whether the starting sulfur level was 5000 or 8000 ppm. Since sulfur removal consumes less than half the hydrogen of desulfurizing from untreated 9000 ppm sulfur feedstocks to 15 ppm,[X] the adjustment is always less than 50 percent. The adjustment is applied as an adjustment ratio to each untreated blendstock type for a refinery with a distillate hydrotreater. The adjustment ranged from 0.80 for PADD 5, which has an estimated untreated distillate sulfur level of 3010 ppm, to 1.0 for PADD 3, which has an estimated untreated distillate sulfur level of 9,350 ppm. No adjustment was necessary for the already hydrotreated part of the distillate pool since this subpool is always assumed to contain 340 ppm sulfur.

For refineries without a distillate hydrotreater, our adjustment to account for differing starting sulfur levels assumes that they currently blend only unhydrotreated blendstocks into the distillate that comprises the high-sulfur pool. Thus, we are making our adjustments based on a lower starting sulfur level. Our adjustment for these refineries ranged from 0.79 for PADD 4, which has an estimated untreated sulfur level of 2550 ppm, to 0.83 for PADD 3, which has a starting sulfur level of 3780 ppm. The various hydrogen consumption adjustment values are summarized in Table 7.2.1-5.

Table 7.2.1-5
Hydrogen Consumption Adjustment Factors: Grassroots Units

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Refinery with Distillate HT	0.84	0.89	1.0	0.81	0.80
No Distillate HT	0.80	0.80	0.83	0.79	0.79

7.2.1.2.1.3 Desulfurizing High-Sulfur Distillate Fuel to a 500 ppm Cap

Finally, we needed to provide inputs for our cost model for desulfurizing untreated, high-sulfur distillate to meet a 500 ppm sulfur standard, which is the first step of our two-step program. These inputs are estimated by simply subtracting the inputs for the revamped unit for desulfurizing 500 ppm diesel fuel down to 15 ppm from the inputs for a grassroots unit for desulfurizing untreated diesel fuel down to 15 ppm. The untreated to 500 ppm inputs for our refinery cost model are summarized in Table 7.2.1-6.

[X] Much of the hydrogen consumption is due to the saturation of olefins, or partial saturation of aromatics.

Table 7.2.1-6
Process Projections for Installing a New Unit for Desulfurizing
Untreated Diesel Fuel Blendstocks to Meet a 500 ppm Sulfur Standard

	Straight-Run	Coker Distillate	Light Cycle Oil
Capacity BPSD (bbl/day)	25,000	25,000	25,000
Capital Cost (ISBL) (MM$)	15	18	21
Liquid Hour Space Velocity (Hr^{-1})	2.4	1.9	1.3
Hydrogen Consumption (SCF/bbl)	144	620	725
Electricity (KwH/bbl)	0.2	0.4	0.4
HP Steam (Lb/bbl)	-	-	-
Fuel Gas (BTU/bbl)	8770	8410	8410
Catalyst Cost ($/BPSD)	0.1	0.2	0.3
Yield Loss (%)			
Diesel	0.5	1.1	1.2
Naphtha	-0.4	-0.7	-0.8
LPG	-0.02	-0.04	-0.04
Fuel Gas	-0.02	-0.06	-0.07

Again, a hydrogen consumption adjustment was made for starting sulfur levels that differ from 9000 ppm. In this case, the hydrogen adjustment ended up being larger than the grassroots desulfurization unit as the adjustment to the hydrogen consumption for going from untreated to 500 ppm comprises a larger percentage of the total hydrogen consumption. This adjustment is for a refinery with a distillate hydrotreater. The adjustment is applied as an adjustment ratio to each unhydrotreated blendstock type and it ranged from 0.69 for PADD 5, which has an estimated untreated distillate sulfur level of 3010 ppm, to 1.0 for PADD 3, which has an estimated untreated distillate sulfur level of 9,350 ppm. No adjustment was necessary for the already hydrotreated part of the distillate pool since this subpool is always assumed to contain 340 ppm sulfur.

For refineries without a distillate hydrotreater, our analysis does not assume that they currently hydrotreat any of the distillate that comprises the high-sulfur pool. Thus, we estimate a somewhat lower starting sulfur level. Our adjustment for these refineries ranged from 0.67 for PADD 4, which has an estimated untreated sulfur level of 2550 ppm, to 0.73 for PADD 3, which has a starting sulfur level of 3780 ppm. The various hydrogen consumption adjustment values are summarized in Table 7.2.1-7.

Table 7.2.1-7
Hydrogen Consumption Adjustment Factors: High Sulfur to 500 ppm

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Refinery with Distillate HT	0.75	0.83	1.0	0.70	0.69
No Distillate HT	0.69	0.69	0.73	0.67	0.67

7.2.1.2.1.4 Hydrocrackate Processing and Tankage Costs

We believe refineries with hydrocrackers will have to invest some capital and incur some operating costs to ensure that recombination reactions at the exit of the second stage of their hydrocracker do not cause the diesel fuel being produced by their hydrocracker to exceed the standard. The hydrocracker is a very severe hydrotreating unit capable of hydrotreating its product from thousands of ppm sulfur to nearly zero ppm sulfur; however, hydrogen sulfide recombination reactions that occur at the end of the cracking stage, and fluctuations in unit operations, such as temperature and catalyst life, can result in the hydrocracker diesel product having up to 30 ppm sulfur in its product stream.[24 25] Thus, refiners may need to install a finishing reactor for the diesel stream produced by the hydrocracker. According to vendors, this finishing reactor is a low-temperature, low-pressure hydrotreater that can desulfurize the simple sulfur compounds formed in the cracking stage of the hydrocracker.

Additionally, since the 15 ppm diesel sulfur standard is very stringent, we take into account tankage that will likely be needed. We believe refiners could store high-sulfur batches of highway diesel fuel or nonroad diesel fuel during a shutdown of the diesel fuel hydrotreater. Diesel fuel production would cease in the short term, but the rest of the refinery could remain operative. To account for this, we provided for the cost of installing a tank that would store ten days of 15 ppm sulfur diesel production, sufficient for a ten-day emergency turnaround, which is typical for the industry; the estimated cost for a 270,000 barrel storage tank is $3 million.[26] The cost of the land needed for this tank is assumed to be negligible relative to the cost of the tank. This amount of storage should be adequate for most unanticipated turnarounds. We presumed that each refinery will need to add such storage, though for some refineries, off-spec diesel fuel could also be sold as high-sulfur heating oil or fuel oil.

The cost inputs for the storage tank and the finishing reactor are summarized in Table 7.2.1-8.

Table 7.2.1-8
Process Operations Information for Additional Units used in the Desulfurization Cost Analysis

	Diesel Storage Tank	Distillate Hydrocracker Post Treat Reactor
Capacity	50,000 bbls	25,000 (bbl/day)
Capital Cost (MM$)	0.75	5.7[27]
Electricity (KwH/bbl	—	0.98
HP Steam (Lb/bbl)	—	4.2
Fuel Gas (BTU/bbl)	—	18
Cooling Water (Gal/bbl)	—	5
Operating Cost ($/bbl)	none[a]	see above

[a] No operating costs are estimated directly; however both the ISBL to OSBL factor and the capital contingency factor used for desulfurization processes is used for the tankage as well, which we believe to be excessive for storage tanks so it is presumed to cover the operating cost.

Refiners will also likely invest in a diesel fuel sulfur analyzer.[28] A sulfur analyzer at the refinery provides nearly real-time information regarding the sulfur levels of important streams in the refinery and facilitate operational modifications to prevent excursions above the sulfur cap. Based on information from a manufacturer of such an analyzer, the analyzer costs about $50,000, with an additional $5,000 estimated for installation.[29] Compared with the capital and operating cost of desulfurizing diesel fuel, the cost for this instrumentation is far below 1 percent of the total cost of this program. Because the cost is so small, the cost of an analyzer was assumed covered as a cost contingency described in Section 7.2.1.4.1.

7.2.1.2.2 Process Dynamics IsoTherming

Process Dynamics has licensed a technology called IsoTherming, which is designed to desulfurize both highway and non-highway distillate fuel. At our request, Process Dynamics provided basic design parameters that can be used to project the cost of using their process to meet tighter sulfur caps,[30] which is summarized in the process information table. Subsequently, EPA spoke to a Linde engineer responsible for implementing the IsoTherming unit at the Giant refinery.[31] The hydrogen and utility consumption information obtained earlier from Process Dynamics was adjusted based on these comments, as described in the text further below.

Specifically, Process Dynamics provided design parameters for a revamp of an existing highway desulfurization unit to meet a 15 ppm standard. The revamp involves putting an IsoTherming unit upstream of the existing highway diesel fuel hydrotreater. Thus, when applying the Process Dynamics unit in our cost estimates for meeting the 15 ppm standard, the new Process Dynamics unit itself is assumed to be used as a first stage. As described in more detail in Chapter 5 of the RIA, this configuration takes the most advantage of the inherent benefits of the Process Dynamics IsoTherming desulfurization process.

Process Dynamics provided to EPA process information for the IsoTherming process based on three revamp situations. In the first revamp design, the feedstock consisted of 60 percent straight-run and 40 percent LCO. The unhydrotreated sulfur level was just under 2000 ppm and both the existing hydrotreater and the IsoTherming unit operated at 600 psi. In the second design, the feedstock consisted of 60 percent straight-run, 30 percent LCO and 10 percent light-coker gas oil with an unhydrotreated sulfur level of 9950 ppm. The existing hydrotreater and the IsoTherming unit operated at 950 psi. In the third design, the feedstock was the same as in the second, but the IsoTherming unit was designed to operate at 1500 psi, while the conventional hydrotreating unit operated at 950 psi.

We largely based our cost projections for the IsoTherming process on the second design. The unhydrotreated sulfur level of more than 9000 ppm is more typical for most refiners than 2000 ppm. The 950 psi design pressure for the IsoTherming unit was also thought to preferable to 1500 psi for most refiners. The higher-pressure unit reduces capital and catalyst costs, but higher hydrogen consumption offsets much of the cost savings. The higher-pressure reactors and compressors also have a longer delivery time and there would likely be fewer fabricators. Thus, given that the savings associated with the higher pressure unit were small, we decided to focus on the 950 psi design.

The information provided by Process Dynamics for the 950 psi IsoTherming desulfurization unit is summarized in Table 7.2.1-9. The operation and product quality of the IsoTherming unit is shown separatly from those for the existing conventional hydrotreater. Again, prior to the revamp, the conventional hydrotreater would have processed this feedstock down to roughly 340 ppm sulfur.

Table 7.2.1-9
Process Dynamics IsoTherming Revamp
Design Parameters to Produce 10 ppm Sulfur Diesel Fuel

	Feed Quality	IsoTherming Unit and its Product Quality	Conventional Hydrotreater and Final Product Quality
LCO vol %	30		
Straight-Run vol %	60		
Light-Coker Gas Oil vol%	10		
Sulfur ppm	9950	850	10
Nitrogen	340	38	2
API gravity (degrees)	33.98	34.42	35.84
Cetane Index	44.5	48.5	50.8
H_2 Consumption (scf/bbl)		320	100
Relative H_2 Consumption		75	25
LHSV (hr^{-1})		15/15	3
Relative Catalyst Volume		45	100
Reactor Delta T		15	15
H_2 Partial Pressure		950	950
Electricity (kW)		1525	
Natural Gas (mmbtu/hr)		0	
Steam (lb/hr)		0	

7.2.1.2.2.1 Hydrotreating High-Sulfur Distillate Fuel to 15 ppm

The design parameters provided by Process Dynamics involve the revamp of an existing conventional hydrotreater currently producing highway diesel fuel (i.e., less than 500 ppm sulfur) to produce diesel fuel with a sulfur level well below 15 ppm. Before addressing this situation, however, we will use the Process Dynamics revamp design to project the costs of an IsoTherming unit that processes unhydrotreated distillate fuel (e.g., 3400-10,000 ppm sulfur) down to 7-8 ppm sulfur. This type of unit was not projected to be used under the two-step fuel program. However, we considered such a sulfur reduction step for alternative programs, for which costs are also estimated later in this chapter.

Also, as was done for conventional hydrotreating, we develop cost estimates for applying the IsoTherming process to three individual blendstocks—straight-run, LCO and light-coker gas oil—to be able to project desulfurization costs for individual refineries whose diesel fuel compositions vary dramatically.

We have broken down the derivation of the cost of a stand-alone IsoTherming unit capable of producing 15 ppm diesel fuel into four parts: hydrogen consumption, utilities and yield losses, catalyst cost and capital cost.

Hydrogen Consumption: In this section, we estimate the hydrogen consumption to process individual refinery streams from their uncontrolled levels down to 7-8 ppm sulfur. Process Dynamics provided hydrogen consumption estimates for desulfurizing a mixed feedstock of 60 percent straight-run, 30 percent LCO and 10 percent coker distillate, but not for specific refinery streams. Additionally, Process Dynamics provided information for a hybrid desulfurization unit comprised of a Process Dynamics IsoTherming unit revamping a conventional highway hydrotreater. For the proposed rule, we used the hydrogen consumption values provided by Process Dynamics to estimate the hydrogen consumption for the IsoTherming unit for the individual diesel fuel blendstocks which we model. This information resulted in a hydrogen consumption which was somewhat lower than that of conventional hydrotreating. After the proposal, we asked the Linde engineers to provide their most recent estimate of the hydrogen consumption values for the IsoTherming process based on the in-use data from their commercial demonstration unit. The resulting hydrogen consumption estimates for the IsoTherming process are similar to that of conventional hydrotreating. Consequently, for the final rule analysis we set the hydrogen consumption of the Process Dynamics IsoTherming process to be the same as conventional hydrotreating. The resulting hydrogen consumptions were 1100 scf/bbl for LCO, 850 scf/bbl for other cracked stocks, and 240 scf/bbl for straight-run.

Consistent with the methodology used for conventional hydrotreating, we developed adjustments to each blendstock hydrogen consumption values to reflect differing unhydrotreated sulfur levels. We assumed that the hydrogen consumption for IsoTherming process varied in the same proportions as those for conventional hydrotreating because the treated feed sulfur levels were about the same. Thus, the same hydrogen adjustment factors were used as for conventional hydrotreating, and they can be found in Table 7.2.1-5 and Table7.2.1-7.

Utilities and Yield Losses: We next established the IsoTherming utility inputs for individual blendstocks. The Process Dynamics IsoTherming process saves a substantial amount of heat input by conserving the heat of reaction that occurs in the IsoTherming reactors. This conserved energy is used to heat the feedstock to the unit. This differs from conventional hydrotreating that normally rejects much of this energy to avoid coking the catalyst. According to Process Dynamics, this allows the IsoTherming process to operate with negligible external heat input. In the highway hydrotreater revamp, which is the source of the information provided by Process Dynamics, the existing heater for the highway hydrotreater was hardly needed after the IsoTherming process was added. However, there is still the need for a small heater to heat up the feedstock during unit startup. This affects capital costs. However, when averaged over production between start-ups (generally at least two years), the little amount of fuel used during start-up is negligible. Thus, we estimate no need for either fuel or steam with the IsoTherming process.

As shown in Table 7.2.1-9, Process Dynamics estimated electricity demand to be 1525 kilowatts per 20,000 bbl/day unit in their early estimate of the demands for their unit. However, since the commercial demonstration unit has been operating, Process Dynamics has collected information on the actual electrical consumption of the IsoTherming unit. Process Dynamics engineers estimate that the electrical consumption is about that same as conventional hydrotreating. Thus, for desulfurizing untreated diesel fuel down to 15 ppm, we set the electricity demand as the same as conventional hydrotreating. Thus, we estimate electricity demand at 0.6, 1.1 and 1.2 kW-hr/bbl for straight-run, light-coker gas oil, and LCO, respectively.

This is a decline in electricity consumption compared to the values which Process Dynamics reported in their original document. That the IsoTherming unit would consume the same (or potentially less) electricity as conventional hydrotreating is reasonable considering that no recycle compressor is needed with this technology because large excesses of hydrogen are not fed to the IsoTherming reactor. Recycle compressors are a large electricity consumer. This electricity savings is somewhat offset because of the increased liquid pumping demands required to recycle the diesel fuel through the reactors. While some savings are likely, Process Dynamics suggested we assume that the electricity costs are about the same as conventional hydrotreating.

Process Dynamics did not estimate the specific yield losses for the IsoTherming process. On our request for further information, Process Dynamics indicated that their process causes slightly less than half of the yield loss of conventional hydrotreating. Thus, the yield loss of the Process Dynamics unit was projected to be 50 percent that of conventional hydrotreating, which is proportional to the relative catalyst volume. The resulting projected yield losses are shown in Table 7.2.1-10 below:

Table 7.2.1-10
Estimated Yield Loss for a Process Dynamics IsoTherming Grassroots Unit

Fuel Type	Straight Run	Light Coker Gas Oil	Light Cycle Oil
Diesel Fuel	0.75	1.45	1.65
Naphtha	-0.55	-1.00	-1.15
LPG	-0.03	-0.055	-0.06
Fuel Gas	-0.03	-0.085	-0.10

Catalyst Costs: The catalyst cost for the Process Dynamics process was estimated based on the relative catalyst volume compared with conventional hydrotreating. As shown in Table 7.2.1-9, Process Dynamics indicated that the catalyst volume for the new IsoTherming reactors contained only 45 percent of the volume of the new conventional hydrotreating reactors that Process Dynamics projects would be needed to revamp the existing hydrotreater to produce 10 ppm fuel. We assumed that this same relationship holds for a stand-alone IsoTherming unit. Thus, we multiplied the catalyst costs for conventionally hydrotreating specific blendstocks (shown in Table 7.2.1-4) by 45 percent. The resulting IsoTherming catalyst costs were 0.14, 0.27 and 0.36 $/BPSD for straight-run, light-coker gas oil and LCO, respectively.

Capital Costs: The last aspect of the IsoTherming process to be determined on a per-blendstock basis is its capital cost. Process Dynamics's initial submission of process-design parameters did not include an estimate of the capital cost. We developed our own estimate from the process equipment included, compared with those involved in conventional hydrotreating. As indicated in Table 7.2.1-9, the catalyst volume of the two IsoTherming reactors unit (combined LHSV of 7.5) is roughly 8 times smaller than that of a conventional hydrotreating revamp (LHSV of 0.9 per LHSVs for individual blendstocks from Table 7.2.1-4). Also, because the IsoTherming reactors use a much higher flowrate and is a totally liquid process (no need for both gas and liquid in the reactor), it eliminates the need for an expensive distributor. As mentioned above, the feed pre-heater can be much smaller and less durable, since it is required only for startup. Finally, the IsoTherming process does not require an amine scrubber to scrub the H_2S from the recycle hydrogen stream.

Based on these differences, we estimated that the total capital cost of a stand-alone IsoTherming unit is two-thirds that for a conventional hydrotreater. Thus, the capital costs for a 25,000 bbl per day conventional hydrotreater were reduced by one-third. The resulting IsoTherming capital costs for a 25,000 BPSD unit were $21, $25, and $29 million for treating straight-run, light-coker gas oil and LCO, respectively. The estimated overall capital cost for the specific feed composition shown in Table 7.2.1-9 is $900 per BPSD for the IsoTherming unit, versus $1400 per BPSD for a conventional hydrotreater. More recently, Linde indicated that the capital cost will be roughly $800 per barrel for a 25,000 bbl per day unit.[32] For this analysis, we consequently retained the two-thirds factor relative to conventional hydrotreating ($900 per BPSD).

Summary of Process-Design Parameters: Table 7.2.1-11 summarizes the design parameters used for using the Process Dynamics IsoTherming process to desulfurize untreated distillate fuel to 10 ppm.

Table 7.2.1-11
Process Parameters for a Stand-Alone IsoTherming
25,000 BPSD Unit to Produce 10 ppm Sulfur Fuel from Untreated Distillate Fuel

	Straight-Run (SR)	Other Cracked Stocks	Light Cycle Oil (LCO)
Capital Cost ($MM)	21	25	29
Hydrogen Demand (scf/bbl)	240	850	1100
Electricity Demand (kwh/bbl)	0.6	1.1	1.2
Fuel Gas Demand (btu/bbl)	220	-500	-500
Catalyst Cost ($/bpsd)	0.15	0.29	0.44
Yield Loss (wt%): Diesel Naphtha LPG Fuel Gas	0.75 -0.55 -0.03 -0.03	1.45 -1.00 -0.055 -0.085	1.65 -1.15 -0.06 -0.10

7.2.1.2.2.2 Desulfurizing 500 ppm Sulfur Diesel Fuel to Meet a 15 ppm Sulfur Cap

The derivation of process design parameters for a IsoTherming unit revamp of a conventional hydrotreater is much more straightforward than that of a stand-alone IsoTherming unit, as the design parameters provided by Process Dynamics in Table 7.2.1-9 were for a revamp. The revamp would occur by placing the new Process Dynamics IsoTherming unit as a first stage (uncontrolled to under 500 ppm), before the existing highway highway, thus converting the highway hydrotreater to treating diesel fuel from several hundred ppm to under 15 ppm. Similar to how we characterized the cost inputs above, we have broken down the derivation of the cost of a stand-alone IsoTherming unit capable of producing 15 ppm diesel fuel into four parts: hydrogen consumption, utilities and yield losses, catalyst cost and capital cost.

Hydrogen Consumption: Determining the incremental hydrogen consumption of a Process Dynamics IsoTherming revamp of a conventional hydrotreater requires that the existing hydrogen consumption of the existing conventional hydrotreater be accounted for. As described above, we now estimate that the hydrogen consumption of the Process Dynamics unit to be the same as the conventional hydrotreating unit for the same service. Thus, there would be no change in hydrogen consumption when the Process Dynamics unit replaces the conventional hydrotreating unit for treating diesel fuel from uncontrolled levels down to 500 ppm sulfur. The conventional hydrotreater's new role would be to desulfurize 500 ppm sulfur down to 15 ppm sulfur. The new service of the conventional hydrotreater will define the hydrogen consumption for this Process Dynamics IsoTherming revamp of the conventional hydrotreater unit. The hydrogen consumption of a conventional hydrotreater for treating 500 ppm diesel fuel down to 15 ppm is contained in Table 7.2.1-6 above, which is 96, 230 and 375 standard cubic feet per minute of hydrogen for straight run, coker, and LCO, respectively.

Utilities and Yield Losses: The electricity consumption for a Process Dynamics IsoTherming revamp of a conventional hydrotreater follows the same logic as that for hydrogen. Again the Process Dynamics unit is assumed to have the same electrical demand as the conventional hydrotreater for desulfurizing untreated diesel fuel down to 500 ppm. Thus, the incremental electricity demand for this revamp is the electrical demand for the conventional hydrotreater in its new 500 ppm to 15 ppm service. The electric demand of a conventional hydrotreater for treating 500 ppm diesel fuel down to 15 ppm is contained in Table 7.2.1-6 above, which is 0.4, 0.7 and 0.8 kilowatt hours per barrel for straight run, coker, and LCO, respectively.

Estimating fuel gas consumption for a Process Dynamics revamp of a conventional hydrotreater is more complex because the Process Dynamics unit's fuel gas consumption is not the same as a conventional hydrotreater for desulfurizing undesulfurized diesel fuel down to 500 ppm. This calculation is best shown in Table 7.2.1-12. The table shows the addition of the Process Dynamics unit for desulfurizing each undesulfurized blendstock to 500 ppm, the subtraction of the conventional hydrotreater for the same increment of sulfur control for each blendstock, the addition of the conventional hydrotreater now treating 500 ppm diesel fuel down to 15 ppm for each blendstock, and the net change in fuel gas consumption.

Table 7.2..1-12
Estimate of Fuel Gas Consumption of an IsoTherming Revamp; 500 ppm to 15 ppm

	Straight Run	Coker	LCO
IsoTherming Unit: High Sulfur to 500 ppm (added)	110	-250	-250
Conv. HT: High Sulfur to 500 ppm (subtracted)	8770	8410	8410
Conv. HT 500 ppm to 15 ppm (added)	110	-250	-250
Net Fuel Gas Consumption	-8550	-8910	-8910

As mentioned above, Process Dynamics did not provide estimates of yield losses for the IsoTherming process. Using engineering judgement based on the relative exposure to the catalyst (the Process Dynamics unit only uses 45 percent of the catalyst as a conventional hydrotreater), we estimated that a stand-alone IsoTherming unit would reduce yield losses by 45 percent compared to a stand-alone convention hydrotreater. We applied this factor to the conventional hydrotreater yield loss to estimate the Process Dynamics yield loss. Table 7.2.1-6 shows that the yield loss for straight run feed is 1.0 percent for a conventional hydrotreating revamp (500 ppm to 15 ppm) and Table 7.2.1-4 shows a 1.5 percent loss for a grass roots conventional hydrotreater (uncontrolled to 15 ppm). Thus, the original highway fuel hydrotreater (uncontrolled to 500 ppm) has a yield loss of 0.5 percent for straight run, consistent with that shown in Table 7.2.1-3.

If the IsoTherming revamp reduces the yield loss by 45 percent, its yield loss for straight run is 55 percent of 1.5 percent, or 0.82 percent. Subtracting out the 0.5 percent loss of the original highway hydrotreater means that the IsoTherming revamp had an incremental yield loss of 0.32 percent, or 32 percent of the 1.0 percent yield loss projected for the conventional hydrotreating revamp. Thus, we projected that all of the yield losses shown in Table 7.2.1-13 for a conventional hydrotreating revamp would be only 32 percent as large for an IsoTherming revamp.

Table 7.2.1-13
Estimated Yield Loss for a Process Dynamics IsoTherming Revamp

Fuel Type	Straight Run	Light Coker Gas Oil	Light Cycle Oil
Diesel Fuel	0.32	0.61	0.70
Naphtha	-0.22	-0.42	-0.48
LPG	-0.01	-0.02	-0.03
Fuel Gas	-0.01	-0.035	-0.04

Catalyst Costs: Consistent with the relative catalyst cost for a stand-alone IsoTherming unit, we project that the catalyst cost for an IsoTherming revamp would be 45 percent of that for a conventional hydrotreating revamp.

Capital Costs: Consistent with the relative capital cost for a stand-alone IsoTherming unit, we project that the capital cost for an IsoTherming revamp would be 45 percent of that for a conventional hydrotreating revamp.

Summary of Process Design Parameters: The inputs into our cost model for treating already treated non-highway diesel fuel by the individual refinery streams which is presumed to be 340 ppm is summarized in Table 7.2.1-14.

Table 7.2.1-14
Process Projections for an IsoTherming Revamp
of a Conventional Hydrotreater to Meet a 15 ppm Cap Standard

	Straight Run (SR)	Other Cracked Stocks	Light Cycle Oil (LCO)
Capital Cost ($MM)	10.6	12.5	14.5
Unit Size (bbl/stream Day)	25,000	25,000	25,000
Hydrogen Demand (scf/bbl)	96	230	375
Electricity Demand (kwh/bbl)	0.4	0.7	0.8
Fuel Gas Demand (btu/bbl)	-8550	-8910	-8910
Catalyst Cost ($/bpsd)	0.09	0.18	0.23
Yield Loss (wt%)			
Diesel	0.25	0.48	0.55
Naphtha	-0.18	-0.33	-0.38
LPG	-0.01	-0.02	-0.02
Fuel Gas	-0.01	-0.03	-0.03

7.2.1.2.3 Characterization of Vendor Cost Estimates

Applicability to Specific Refineries: The information provided by the vendors is based on typical diesel fuels or diesel fuel blendstocks. However, in reality, diesel fuel (especially LCO, and to a lesser degree other cracked stocks) varies in desulfurization difficulty based on the amount of sterically hindered compounds present in the fuel, which is determined by the endpoint of diesel fuel, and also by the type of crude oil being refined and other unit processes. The vendors provided cost information based on diesel fuels with T-90 distillation points which varied from 605 ˚F to 630 ˚F, which would roughly correspond to distillation endpoints of 655 ˚F to 680 ˚F. These endpoints can be interpreted to mean that the diesel fuel would, as explained in Chapter V above, contain sterically hindered compounds. Other diesel fuels or diesel fuel blendstocks, such as a straight run diesel fuel with a lower end boiling point, are lighter and would not contain sterically hindered compounds. However, a summer time diesel fuel survey for 1997 shows that the endpoint of highway diesel fuel varies from 600 ˚F to 700 ˚F, thus the lighter diesel fuels would contain no sterically hindered compounds, and the heavier diesel fuels would contain more.[33] Our analysis attempts to capture the cost for each refinery to produce highway diesel fuel which meets the 15ppm cap sulfur standard, however, we do not have specific information for how the highway diesel endpoints vary from refinery to refinery, or from season to season. Similarly, we do not have information on what type of crude oil is being processed by each refinery as the quality of crude oil being processed by a refinery affects the desulfurization difficulty of the various diesel fuel blendstocks. Diesel fuel processed by a particular refiner can either be easier or more difficult to treat than what we estimate depending on how their diesel fuel endpoint compares to the average endpoint of the industry, and depending on the crude oil used. For a nationwide analysis, we believe it is appropriate to base our cost analysis for each refinery on what we estimate would be typical or average qualities for each diesel fuel blendstock. Some estimates of individual refinery costs will be high, others will be low, but be representative on average.

Accuracy of Vendor Estimates: We have heard from refiners in the past that the vendor costs are optimistic and need to be adjusted higher to better assess the costs. While the vendors costs may be optimistic, we believe that there are a multitude of reasons why the cost estimates could be optimistic and adjusting these estimates isn't necessary.

First, in specific situations, capital costs can be lower than what the vendors project for a generic refinery. Many refiners own used reactors, compressors, and other vessels which can be employed in a new or revamped diesel hydrotreating unit. We do not know to what extent that additional hydrotreating capacity can be met by employing used vessels, however, we believe that at least a portion of the capital costs can be offset by used equipment. Additionally, the vendors of conventional hydrotreating which provided cost estimate information for our analysis based their capital costs on the inclusion of an interstage stripper to strip out the hydrogen sulfide between the first and second reactor stages (see Chapter 5 of the RIA). However, vendors today are saying that interstage strippers are not necessary. Thus, the capital costs upon which our conventional hydrotreating costs are based are conservative, which offsets optimism on the part of the vendors.

There are also operational changes which refiners can make to reduce the difficulty and the cost of desulfurizing highway diesel fuel. Based on the information which we received from vendors and as made apparent in our cost analysis which follows, refiners with LCO in their diesel fuel would need to hydrotreat their highway diesel pool more severely resulting in a higher cost to meet the cap standard. We believe that these refiners could potentially avoid some or much of this higher cost by pursuing two specific options. The first option which we believe these refiners would consider would be to shift LCO to heating oil which does not face such stringent sulfur control. The more lenient sulfur limits which regulate heating oil provide room for blending in substantial amounts of LCO. The refineries which could take advantage of shifting LCO to the heating oil pool are those in the Northeast and on the Gulf Coast which have access to the large heating oil market in the Northeast. If refiners could not shift all the LCO to the heating oil pool because of market limitations, refiners could distill its LCO into light and heavy fractions and only shift the heavy fraction to the heating oil pool. Essentially all of the sterically hindered compounds distill above 630°F, so if refiners undercut their LCO to omit these compounds, they would cut out about 30 percent of their LCO. We expect that refiners could shift the same volume of non-LCO distillate from these other distillate pools to the NRLM pool to maintain current production volumes of all fuels. The T-90 maximum established by ASTM may limit the amount of LCO, and especially heavy LCO, which can be moved from NRLM diesel fuel into the heating oil pool. Another option, of course, would be to move this dirty distillate fraction into number 4 or number 6 marine bunker fuel. For those refineries which could trade the heavy portion of LCO with other blendstocks in the heating oil pool from their own refinery or other refineries, we presume that those refiners could make the separations cheaply by using a splitting column for separating the undercut LCO from the uncracked heavy gasoil in the FCC bottoms.

Another option for refineries which are faced with treating LCO in its nonroad diesel fuel would be to sell off or trade their heavy LCO to refineries with a distillate hydrocracker. This is a viable option only for those refineries which are located close to another refinery with a distillate hydrocracker. The refinery with the distillate hydrocracker would upgrade the purchased LCO into gasoline or high quality diesel fuel. To allow this option, there must be a way to transfer the heavy LCO from the refinery with the unwanted LCO to the refinery with the hydrocracker, such as a pipeline or some form of water transport. We asked a refinery consultant to review this option. The refinery consultant corroborated the idea, but commented that the trading of blendstocks between refineries is a complicated business matter which is not practiced much outside the Gulf Coast, and that the refineries with hydrocrackers that would buy up and process this low quality LCO may have to modify their distillate hydrocrackers.[34] The modification which may be needed would be due to the more exothermic reaction temperature of treating LCO which could require refiners to install additional quenching in those hydrocrackers. Additionally, LCO can demand 60 to 80 percent more hydrogen for processing than straight run material. The refiners which could potentially take advantage of selling or trading their LCO to these other refineries are mostly located in the Gulf Coast where a significant number of refineries have hydrocrackers and such trading of blendstocks is common. However, there are other refineries outside of the Gulf Coast which could take advantage of their very close location to another refinery with a distillate hydrocracker. Examples for these refining areas where a hydrocracker could be shared include the Billings, Montana area and Ferndale, Washington.

As we summarized in Chapter 5, catalysts are improving and expected to continue to improve. Our costs are based on vendor submissions and incorporate the most advanced new catalysts available at that time. However, there are several new lines of catalysts available now which are more active than the previous lines of catalysts upon which our costs are based. As catalysts continue to improve, the cost of desulfurizing diesel fuel will continue to decrease.

In summary, while some contend that the vendor cost estimates are optimistically low, there are a number of reasons why we believe the cost of desulfurizing diesel fuel to meet the 15 ppm cap standard may be even lower than estimated. Vendors are expected to continue to improve their desulfurization technology such as the activity of their catalysts. Also, refiners have several cost cutting options at their disposal, such as using existing spare equipment, to lower their capital costs which is not considered here. Also, refiners may be able to resort to either of two operational options to reduce the amount of LCO in their highway diesel fuel.

We are aware that there are potentially other capital and operating costs in the refinery which would contribute the projected cost of desulfurizing diesel fuel beyond that provided to us by the vendors. For example, refiners may need to expand their amine plant or their sulfur plant to enable the processing of the sulfur compounds removed from diesel fuel. Then the small amount of additional sulfur compounds treated would incur additional operating costs. Thus, as described below, we adjusted the projected capital and operating costs upward to account for these other potential costs which we have not accounted for explicitly.

7.2.1.3 Refinery-Specific Inputs

There are a number of reasons why we estimated refining costs on a refinery-specific basis. First, it provides more precise and realistic estimates of desulfurization costs, as some differences between individual refineries can be represented (e.g., distillate fuel composition, production volumes, etc.). These costs are approximate, as we do not have precise data on the distillate composition for all U.S. refineries. While we do know historic distillate production levels, we do not know how these will change in the future. Still, the distribution of costs across refineries facillitated by the factors developed in this section will provide much more insight into how desulfurization costs can vary between refineries. The alternative would be to estimate desulfurization costs for the average U.S. refinery and assume that this cost applied to all refineries. Given the wide range in refinery capacities and their relative production of highway diesel fuel and high sulfur distillate, the national average approach would be overly simplistic.

Second, a refinery specific approach to costs allows us to better represent the potential interactions between the 15 ppm cap for highway diesel fuel and the NRLM sulfur caps associated with this rule. We recently received refiners' plans regarding their compliance with the 15 ppm highway diesel fuel sulfur cap. Being projections, these plans are subject to change. However, these projections allow us to reasonably estimate the ways in which refiners might take advantage of efforts to comply with the highway fuel standards in complying with the NRLM standards.

Third, the refinery specific costs can be combined into a distribution of costs for the entire refining industry. This distribution of costs allows us to better estimate the number of refineries likely to be affected by this rule. It also provides insight into the range of costs likely to be experienced by refineries, particularly the difference in costs between those facing the lowest costs and those facing the highest costs. This will also provide greater insight into how NRLM diesel fuel prices might be affected by this rule, as well as refiners' ability to recover capital costs.

Fourth, the development of refinery specific costs allows us to better estimate how small refiners might be affected by this rule, in particular how their costs differ from their larger competitors.

Of the many factors which affect desulfurization costs, there are four which vary significantly from refinery to refinery and which we have estimated quantitatively:

1) the composition of its no. 2 distillate pool (e.g., the percentages of LCO and other cracked stocks),
2) the percentage of its no. 2 distillate which is already being hydrotreated,
3) the volume of no. 2 distillate
4) which specific refineries are most likely to produce lower sulfur NRLM fuel.

The following four subsections discuss how we developed refinery-specific factors for each of these four factors.

7.2.1.3.1 Composition of Distillate Fuel by Refinery

In section 7.2.1.2, we developed desulfurization costs as a function of the blend stocks comprising the diesel fuel being processed, as well as other factors. In this section, we describe how we estimated each refinery's distillate blendstock diesel composition.

Refiners do not publish blendstock composition data, nor do they submit it to regulators as part of any regulatory requirements. The only available information is an industry survey conducted in 1996, which published compositional data for all the surveyed refiners within a PADD. Thus, we developed a methodology to estimate each refinery's diesel fuel composition from the aggregated data available from 1996. We then revised these compositions to reflect changes in the capacities of those types of equipment which produce distillate blendstock which have occurred since that time. Finally, we applied one further change to the compositional data which we believe will occur as a result of the 15 ppm highway fuel cap.

The only available data on the composition of diesel blend stocks is from a survey conducted by API and NPRA in 1996. This survey was sent to all domestic refiners and the responses covered 79 percent of the total distillate produced by domestic refineries in 1996. The blendstock composition of highway diesel fuel and No. 2 high sulfur distillate fuel were surveyed separately. The blendstock composition of the combined pool can also be estimated by volume weighting the compositions of the two distillate pools.

Table 7.2.1-15 summarizes the survey results for highway diesel fuel, high sulfur distillate fuel and the combined distillate pool for refiners outside of California. California refiners were excluded due to the unique specifications which California distillate must meet, namely low aromatics and high cetane limits. Also, due to the fact that California has already passed regulations requiring 15 ppm nonroad fuel, this NRLM rule will have a small impact on California refiners. The survey also included whether or not the particular blendstock was hydrotreated. This hydrotreating information will be used in the next section which addresses the hydrotreated fraction of each refinery's distillate. According to the cost estimation methodology described above, desulfurization costs depend on blendstock composition and overall hydrotreated fraction, but not on the specific blendstocks which are hydrotreated. Therefore, we do not consider whether the particular blendstock has been hydrotreated here.

Table 7.2.1-15
Distillate Composition (Excluding California Refiners): 1996 API/NPRA Survey (vol%)

	Highway Diesel Fuel	High Sulfur Distillate	All No. 2 Distillate
Straight Run	64%	63%	64%
LCO	23%	22%	22%
Other Cracked Stocks	9%	5%	8%
Hydrocrackate	4%	10%	6%

As can be seen, the composition of national average highway fuel and high sulfur distillate are quite similar. This led us to assume, for the purpose of this analysis, that each refinery sent the same fraction of LCO and other cracked stocks to its highway fuel and high sulfur distillate pools. This same information was used as the basis for our cost projections presented in the NPRM for this rule.

The next step in this analysis was to determine how each refinery's distillate pool might differ in composition. For example, some refineries do not have an FCC unit. Thus, their distillate would contain no LCO. Others do not have cokers, hydrocrackers, etc. Thus, we allocated the volume of each blendstock in the national distillate pool to each refinery in proportion to the capacity of its equipment which produces each blendstock. As described in Section 5.1, LCO is produced in FCC units, hydrocrackate is produced by hydrocrackers and other cracked stocks are primarily produced by cokers, as well as other thermal cracking units.

While general rules of thumb are available which estimate the volume of distillate produced in each of these units, in most cases, we have sufficient information available to estimate, on a national average basis, these conversion factors. EIA's Petroleum Supply Annual for 1996 states that domestic refiners produced a total of 3.06 million barrels per day of No. 2 distillate in 1996. By multiplying this volume by the percentages of LCO, other cracked stocks, and hydrocrackate in all No. 2 distillate from Table 7.2.1-15 above, we can estimate the total volume of each of these blendstocks which was produced in 1996. EIA also publishes the capacity of each refinery's processing units. By summing these up, we can estimate the total FCC, coker and thermal cracking and hydrocracker units existing in domestic refineries in 1996.

The situation with cokers and other thermal crackers is somewhat more complex, as the conversion of feedstock into distillate does not tend to be the same in these units. Thus, their capacities cannot simply be summed and assumed to have the same conversion rate. One industry consultant estimated that delayed cokers tend to convert 30 percent of their feedstock into distillate, while fluidized cokers, visbreakers, and other thermal crackers are less efficient in this regard, converting only 15 percent. Thus, we assumed that the conversion rate for other thermal crackers was half that of cokers. Practically, we effected this assumption by discounting the capacity of other thermal crackers by a factor of two before adding them to coking capacity.

Prior to making this comparison, however, one more adjustment must be made. Refiners outside of California with hydrocrackers typically feed LCO and other cracked stocks to their hydrocracker. Straight run distillate might also be fed to a hydrocracker which produces gasoline blendstock. However, we believe that after 2006, the 15 ppm highway diesel fuel cap will encourage refiners to shift as much LCO and other cracked stocks as possible to their hydrocrackers. Thus, for refineries with hydrocrackers and FCC units, we assumed that any LCO produced would be sent to the hydrocracker, up to the capacity of the hydrocracker.[Y] Similarly, for refiners with hydrocrackers and cokers or other thermal crackers, we assumed that any other cracked stocks produced would be sent to the hydrocracker, up to the capacity of the

[Y] This assumes that both the FCC unit and the hydrocracker operate at the same percent of capacity, which is reasonable.

hydrocracker minus any LCO sent to the hydrocracker. Table 7.2.1-16 summarizes this information.

Table 7.2.1-16
Conversion of Heavy Oils to Distillate in 1996

	Total U.S. Refining Capacity (BPD)	Total Distillate Blendstock Produced (BPD)	Percentage of Capacity Converted to Blendstock
FCC Units (LCO)			
Total	4,936,940	1,053,610	---
After Shift to Hydrocrackers	2,951,287	643,043	22%
Coking and other thermal crackers * (Other cracked stocks)			
Total	2,664,400	400,193	---
After Shift to Hydrocrackers	1,771,505	256,728	15%
Hydrocracker (hydrocrackate)	927,390	177,265	19%

* 100% of coker capacity plus 50% of the capacity of other thermal crackers

By taking the ratio of the volume of distillate blendstock produced to the total capacity of the type of equipment which produces it, we can estimate the percentage of this capacity which is converted into each type of blendstocks. These percentage are also shown in Table 7.2.1-16. It should be noted that these figures are likely lower than the conversions which would be actually seen during unit operation. The conversions shown in Table 7.2.1-16 are based on rated unit capacity and actual distillate production. Units typically operate at less than capacity over the course of a year. This utilization percentage does not need to be explicitly considered here as the unit capacity for each refinery and that for the nation as a whole are both on a nameplate rating basis. Use of a capacity utilization rate would simply adjust both figures and cancel out within the methodology.

Since we know the capacity of the various unit in each refinery in 1996, we could estimate the volume of each blendstock produced by each U.S. refinery in 1996 by multiplying these capacities by the above conversion factors. However, many refineries have increased the capacities of various units since 1996. As we are using these blendstock compositions to project desulfurization costs in 2007 and beyond, it would be desirable to reflect the impact of these changes in capacity in our analysis. The latest data are from 2002. Thus, we multiplied each refinery's 2002 unit capacities (per EIA) by the above conversion factors to estimate the volume of each blendstock produced by each refinery in this year.

This is a marked improvement from the NPRM analysis. In the NPRM, we used refinery unit capacities existing in the year 2000 (as estimated in the Oil and Gas Journal). These 2000 capacities were combined with the 1996 API/NPRA survey results and distillate production data from 2000 to develop an analogous set of conversion factors. The use of 1996 unit capacities to develop the conversion factors is more consistent with the survey results. The use of 2002 unit capacities incorporates two additional years of changes in refinery configurations into the analysis.

We also decided to use unit capacities as estimated by EIA in lieu of those published by the Oil and Gas Journal. Reviewing both sets of unit capacities, particularly that for hydrotreating capacity used in Section 7.2.1.3.2 below, we found greater consistency between the production volumes of various distillate fuels, as well as between the capacities of the various units, with the EIA estimates than with those published by the Oil and Gas Journal. Therefore, we decided to use the EIA estimates for this final NRLM rule analysis. Also, in the NPRM, the use of distillate compositions from 1996 and unit capacities from 2000 was inconsistent to some degree and the above methodology eliminates this problem.

In addition, the use of 2002 unit capacities provides an automatic adjustment for changes in refinery configurations from 1996 to 2002. In the NPRM, our methodology basically assumed that the overall distillate composition in 1996 continued unchanged into the future. One of the comments we received on the NPRM cost estimates was that we had under-estimated desulfurization costs by assuming that the 1996 distillate composition was not changing over time. The commenters pointed out that the average crude oil being processed in domestic refineries was getting heavier (lower API gravity) and more sour (higher sulfur) over time, which would negatively affect distillate composition from the point of view of desulfurization. They suggested that we should adjust our mix of blendstocks and the amount of sulfur needing to be removed to account for this trend.

We reviewed the quality of the U.S. crude oil slate between 1996 and 2002 and indeed found that the API gravity of average crude oil had decreased by 2.3 percent from 31.1 to 30.4. (The sulfur content of crude oil also increased, but this will be considered in Section 7.2.1.3.2 below when we estimate the percentage of NRLM fuel which is hydrotreated prior to this rule.) Heavier crude oils tend to produce heavier feedstocks to the FCC, coker and hydrocrackers, which can affect the conversion of these feedstocks into distillate. The yield of LCO from an FCC unit tends to vary inversely with conversion,[Z] with higher volumes of LCO produced at lower conversion rates. Heavier crude oils generally produce a heavier FCC feed stock which lowers FCC conversion. This would tend to increase the production of LCO from FCC units. The same would be generally true for cokers and other thermal cracking units.

However, since 1996 refiners have made several process changes which tend to increase FCC conversion. Since 1996, FCC feed hydrotreating capacity has increased by 24 percent, while FCC capacity only increased by 6 percent.[35] FCC feed hydrotreating reduces the density (increases the API gravity) of the FCC feedstock, which increases conversions and decreases

[Z]FCC conversion is defined as the volume percent of FCC feed throughput that is converted to products lighter than LCO and clarified oil/slurry oil, ((FCC feed - LCO product-slurry oil product)/ FCC feed)*100, per volume basis.

LCO yields in the FCC unit. Also, hydrocracking capacity has increased by 20 percent. Since these units can process poor quality LCO, this mitigates the effect of heavier crude oils. According to several FCC technology licensors, refiners are also using more active FCC catalysts and have added or upgraded their FCC process technologies since 1996. These changes should also increase FCC conversions and decreases LCO yields. Thus, changes have occurred since 1996 which both increase and decrease the production of LCO from FCC units. It is not possible to quantitatively estimate the impact of each of these changes, nor the net change in LCO yield. In general, we believe that the impact of heavier crude oil is smaller than the impact of newer FCC technology and increased FCC hydrotreating capacity. Thus, the inability to quantitatively account for these changes should not lead to an under-estimation of desulfurization costs. However, due to the compensating nature of these changes, we believe that the overall change in the quantity and quality of LCO and other cracked stocks being produced today is small and would not significantly affect desulfurization costs.

Also, the processing of heavier crude oil has led the U.S. refining industry to increase capacity of cokers and hydrocrackers relative to crude oil processing capacity. As mentioned above, our methodology automatically adjusted distillate composition for this trend. Thus, we believe that our current methodology reflects current crude oil quality as much as possible using available information. While our methodology does not account for future changes in crude oil quality, the changes seen below between 1996 and 2002 are quite small and indicate that changes likely in the future would also be very small.

Table 7.2.1-17 shows how updating these estimates from 1996 to 2002 affected national average distillate composition outside of California.

Table 7.2.1-17
National Average Distillate Composition Excluding California (Vol%)

	1996	2002
Straight Run	65%	62%
LCO	21%	21%
Other Cracked Stocks	8%	10%
Hydrocrackate	6%	7%

We made one last adjustment to distillate composition to reflect a shift we believe will occur when the 15 ppm sulfur cap begins to apply to highway diesel fuel in 2006. As shown in Table 7.2.1-17 above, the API/NPRA survey found that the hydrocrackate fraction of high sulfur distillate was much greater than that in highway diesel fuel. The reason for this is not obvious, as the low sulfur level of hydrocrackate would presumably been valuable in producing 500 ppm highway fuel. It may be that most highway fuel has be hydrotreated regardless of the percentage of hydrocrackate added, and the use of hydrocrackate in high sulfur distillate allows a significant portion of this fuel to avoid hydrotreating. In any event, the primary properties which differ between highway diesel fuel and high sulfur distillate are sulfur content and cetane number and refiners can use a wide range of blendstock compositions to meet these specification.

When the 15 ppm cap starts to apply to highway diesel fuel, however, the economic incentive to blend hydrocrackate into highway diesel fuel will increase dramatically. Thus, we believe that refiners will shift hydrocrackate from high sulfur distillate to highway diesel fuel. However, most high sulfur distillate is either NRLM diesel fuel or sold as either NRLM fuel or heating oil. Thus, it must have a minimum cetane number of 40. Therefore, we did not believe that it would be feasible for a refiner to shift unhydrotreated LCO or other cracked stocks from highway diesel fuel to high sulfur distillate. Therefore, we assumed that refiners would only shift hydrotreated blendstocks to compensate for the hydrocrackate shift. We assumed that the composition of this shift would reflect the refinery's average distillate composition (i.e., percentage of straight run, LCO and other cracked stocks). We assumed that a refiner would shift all of their hydrocrackate to highway diesel fuel as long as there was sufficient hydrotreated material to shift from highway fuel to high sulfur distillate. (The hydrotreated fraction of each refinery's distillate is discussed in the next section.) For all except five refineries, all of the hydrocrackate was shifted to highway fuel. Three refiners lacked sufficient volume of hydrotreated blendstocks for all their hydrocrackate to be shifted. Two refiners produced less highway diesel fuel than their estimated production of hydrocrackate. Overall, the hydrocrackate portion of highway diesel fuel increased to 8.9 percent, while that for high sulfur distillate decreased to 1.6 percent.

The final compositions of highway and high sulfur distillate after implementation of the 15 ppm sulfur cap on highway fuel, but prior to this NRLM rule are shown below in Table 7.2.1-18. These national averages were calculated by 1) applying the above conversion factors to each refinery's unit capacities to estimate the volume of each blendstock being produced by that refinery, 2) spreading the volume of each blendstock to the refinery's highway diesel fuel and high sulfur distillate fuel pools in proportion to the refinery's production of each of the two fuels pool (as estimated in Section 7.2.3.3 below), 3) shifting hydrocrackate to highway fuel in return for other hydtrotreated blendstocks, as discussed above, 4) summing the volumes of each blendstock type in each fuel pool across all refineries and 5) dividing these blendstock volumes by the total production of highway and high sulfur fuel, respectively. We used each refinery's projected distillate composition to estimate its cost of meeting the 500 and 15 ppm NRLM sulfur caps, not the national average composition.

Table 7.2.1-18
Distillate Composition: After Implementation of the 15 ppm Highway Fuel Sulfur Cap*

	Highway Diesel Fuel	High Sulfur Distillate	All No. 2 Distillate
Straight Run	61%	66%	62%
LCO	20%	23%	21%
Other Cracked Stocks	10%	9%	10%
Hydrocrackate	9%	2%	7%

*excludes California.

In order to provide an indication of the range of distillate compositions which we projected using this methodology, we developed distributions of the percentages of LCO and other cracked stocks in various refiners distillate. These are shown in Table 7.2.1-19 below.

Table 7.2.1-19
Distribution of LCO and Other Cracked Stocks in High Sulfur Distillate Prior to the NRLM Rule (U.S. Refineries Producing High Sulfur Distillate)

	Percentage of LCO and Other Cracked Stocks in the Distillate Pool								
	0%	<10%	<20%	<25%	<30%	<40%	<50%	<80%	100%
LCO									
Number of Refineries	47	48	53	60	76	92	96	99	101
Cumulative % of High Sulfur Distillate Volume	35	36	45	49	71	87	94	98	100
Other Cracked Stocks									
Number of Refineries	71	73	79	87	92	97	101	101	101
Cumulative % of High Sulfur Distillate Volume	53	61	66	85	88	90	100	100	100

As shown above, in 2002, high sulfur distillate fuel produced by U.S. refineries contains between zero to over 80 percent LCO. Forty-seven U.S. refineries, which produce about 35 percent of the high sulfur distillate in the U.S., blend no LCO into their distillate. The high sulfur distillate from the remaining 54 refineries averages about 33 percent LCO by volume. On average, high sulfur distillate contains 21.1 percent LCO in 2002 versus 21.3 percent in 1996. This reflects the fact that FCC unit capacity grew slightly less between 1996 and 2002 than total domestic distillate production volume.

Similarly, we estimate that about half of the high sulfur distillate fuel in the U.S, which is produced by 71 refineries, does not contain any other cracked stocks from cokers, visbreakers and thermal crackers. Of the refineries which produce other cracked stocks, their distillate fuel contains an average of 20.0 percent of other cracked stocks in 2002. On average, the estimated percentage of other cracked stocks being blended into high sulfur distillate increased slightly from 9.2 percent in 1996 to 9.4 percent in 2002. Thus, coking capacity increased slightly faster than total distillate production.

7.2.1.3.2 Sulfur Content and Hydrotreated Fraction of High Sulfur Distillate

Like distillate composition, per the cost methodology developed above, the sulfur content and hydrotreated fraction of high sulfur distillate affects the cost of desulfurization. There are two effects. One relates to the amount of hydrogen consumed in hydrotreating. The other relates to the capital cost of a hydrotreater.

Regarding hydrogen consumption, in addition to removing sulfur, hydrotreating also saturates olefins and most poly-nuclear aromatics. These latter effects occur almost regardless of the degree of sulfur reduction. Thus, distillate which is being hydrotreated today has already had its olefins and poly-nuclear aromatics removed. Thus, subsequent hydrotreating of already hydrotreated blendstocks to reduce sulfur further in response to this NRLM rule does not consume hydrogen related to olefin or poly-nuclear aromatic saturation. The other effect relates to the capital investment needed to meet the 500 ppm NRLM cap in 2007. Material that is already being hydrotreated to 500 ppm or less need not be treated at all during the first step of the NRLM fuel program.

As mentioned in Section 7.2.1.2.1.2, we were not able to incorporate the change in hydrogen consumption due to olefin and poly-nuclear aromatic saturation associated with changing degrees of current hydrotreating. Differences in total hydrogen consumption between various refineries should only be a few tenths of a penny per gallon. Thus, the use of an average level of olefin and poly-nuclear aromatic saturation lessened the refinery-specific nature of our estimates to a slight degree.

Regarding capital costs, we were able to incorporate differences in expected capital investment needed to desulfurize unhydrotreated and hydrotreated blendstocks to meet the 2007 500 ppm NRLM cap. This improved our ability to predict overall desulfurization costs, the number of refineries affected by the NRLM rule and how small refiners might be differentially impacted by the rule.

In addition to whether a blendstock has been previously hydrotreated or not, the starting sulfur content also affects the volume of hydrogen needed to reduce sulfur to meet a 500 ppm cap. In the NPRM, we started with the 1996 API/NPRA fuel quality survey to obtain estimates of the portion of highway and high sulfur distillate which receives at least some hydrotreating. We then used in-use fuel survey data to estimate the sulfur level of high sulfur distillate produced in 1996. Assuming that the sulfur content of the hydrotreated portion of this fuel was the same as that for highway diesel fuel (340 ppm), we then back-calculated the sulfur content of the non-hydrotreated portion of high sulfur distillate, so that the blend matched the in-use sulfur level of finished high sulfur distillate. We then assumed that these 1996 estimates also applied to current and future high sulfur distillate prior to the NRLM rule.

We received comment on the NPRM that the sulfur content of crude oil had been increasing since the 1996 API/NPRA survey was conducted. The commenters argued that this would increase the sulfur content of high sulfur distillate and increase desulfurization costs. Therefore, we have expanded the methodology used in the NPRM analysis to estimate both the sulfur content and hydrotreated fraction of high sulfur distillate.

We first reviewed data on the sulfur content of crude oils processed by U.S. refineries and found that sulfur content had indeed increased. We have incorporated this increase in crude oil sulfur content into the estimates developed in this section. However, as described in Section 7.1 above, there is no evidence so suggest that the sulfur content of high sulfur distillate has increased since 1996. Thus, it is likely that a greater percentage of the volume of high sulfur distillate blendstocks are being hydrotreating than was the case in 1996. We have incorporated a change in the hydrotreated fraction from 1996 into this analysis, as well. Finally, we also reviewed the hydrotreating and hydrocracking capacities of U.S. refineries in 1996 and 2002, as well as the relative production of highway diesel fuel and high sulfur distillate to confirm that sufficient hydrotreating capacity exists to hydrotreat a greater fraction of high sulfur distillate blendstocks.

Table 7.2.1-20 presents many of the primary inputs for our analysis. These estimates are intended to represent high sulfur distillate produced in the year 2002, but without consideration of an increase in crude oil sulfur content. Due to the significant differences in hydrotreating percentages seen across PADDs, we incorporated these PADD-specific estimates as much as possible.

Table 7.2.1-20
Quality of High Sulfur Distillate from
Non-California Refineries: “2002" Prior to Consideration of Increased Crude Oil Sulfur

	PADD				
	1	2	3	4	5
High Sulfur Distillate Pool					
Sulfur content (ppm)	2925	2973	3776	2549	2566
% Hydrotreated *	27	31	44	17	2
High Sulfur Distillate Produced by Refineries with Hydrotreaters					
% of high sulfur distillate pool	81	70	95	40	48
% Hydrotreated	33	45	46	43	4
Sulfur content of portion not hydrotreated (ppm)	4214	5081	6739	4237	2646

* Assumed to be the same as in 1996 API/NPRA survey.

The sulfur content of the high sulfur distillate pool in each PADD were taken from Table 7.1-40 in Section 7.1 above. A direct estimate of the portion of the 2002 distillate pool which is hydrotreated is not available. Therefore, we assumed that this figure has not changed since the API/NPRA survey. This necessitates the consideration of increased sulfur content between 1996 and 2002, which is addressed below. As can be seen, a significant percentage of high sulfur distillate received some hydrotreating in 1996, despite the fact that the final sulfur level is 2000 ppm or more. This is likely necessary to improve the stability of untreated LCO, as well as meet applicable cetane and sulfur specifications with blend stocks which can exceed 10,000 ppm sulfur and have a cetane number of less than 15 prior to hydrotreating. The PADD with the highest percentage of hydrotreated high sulfur distillate is PADD 3, while the lowest is PADD 5 (outside of California). Within PADD 5, Alaska’s refineries are believed to have the lowest hydrotreated percentage (zero), since none of the Alaskan refineries have distillate hydrotreaters.

The hydrotreated blendstocks sent to the high sulfur distillate pool are assumed to be part of a larger pool of hydrotreated blendstocks also used to produce highway diesel fuel. We believe that this is reasonable because many refiners likely only have a single hydrotreater and they are simply blending more hydrotreated material into their highway diesel fuel than into their high sulfur distillate. In this case, we assume that all of the hydrotreated material contains 340 ppm sulfur, the current average sulfur level for highway diesel fuel. Some larger refiners likely have two or more hydrotreaters which could be treating highway diesel fuel blendstocks and high sulfur distillate blendstocks differently. However, in this case, we have no way of estimating the sulfur levels of either the hydrotreated or non-hydrotreated portions of the high sulfur distillate. Thus, we assumed that the 340 ppm sulfur content applied to all hydrotreated blendstocks. Overall, this assumption has little effect on the estimation of NRLM desulfurization costs. As will be seen below, we have estimates of both the hydrotreated fraction of high sulfur distillate and of its final sulfur level. If the sulfur level of hydrotreated blendstocks going to the high sulfur distillate pool contain more than 340 ppm sulfur, the the sulfur content of the non-hydrotreated portion of the pool much contain less sulfur than estimated below. The total amount of sulfur requiring removal is the same in either case.

Some refiners do not have a distillate hydrotreater. Therefore, the percentage of their high sulfur distillate which is hydrotreated is zero. In order for the entire high sulfur distillate pool to be hydrotreated to the degree shown in Table 7.2.1-17, the portion of distillate produced by refiners with distillate hydrotreaters must be higher. In order to estimate these percentages, we reviewed EIA data for both distillate production and distillate hydrotreating capacity. The former data are confidential and were received directly from EIA. The latter came from their 2002 Petroleum Supply Annual. For each PADD, we determined the percentage of all high sulfur distillate produced by refiners with distillate hydrotreaters. These figures are shown in Table 7.2.1-20 above. We calculated the percentage of the high sulfur distillate pool produced by refineries with hydrotreaters by dividing the hydrotreated percentage for the entire pool by the percentage of distillate produced by refineries with hydrotreaters. These higher hydrotreated percentages are shown on the second to the last line of Table 7.2.1-20.

As discussed above, we assume that the sulfur content of the hydrotreated portion of high sulfur distillate is the same as that of highway diesel fuel, or 340 ppm. As discussed in Chapter 5, the sulfur content of hydrocrackate is very low, less than 50 ppm. Knowing the final sulfur level and the percentage of hydrotreated blendstock in high sulfur distillate from Table 7.2.1-20 above (which includes hydrocrackate) and the percentage of hydrocrackate from Table 7.2.1-18, we can back-calculate the sulfur content of the unhydrotreated blendstocks comprising the rest of the high sulfur distillate pool. These sulfur levels are also shown in Table 7.2.1-20.

The final step is to incorporate the effect of an increase in crude oil sulfur content. Table 7.2.1-21 shows the average sulfur content of crude oil processed in each PADD in both 1996 and 2002. As can be seen, crude oil became more sour in all but PADD 1.

Table 7.2.1-21
Sulfur Content of Crude Oil Processed by U.S. Refineries (weight %)

PADD	1996	2002	Percent Change
1	0.94	0.86	-8.5
2	1.08	1.31	21.3
3	1.22	1.65	35.3
4	1.31	1.40	6.9
5 (Non-California)	1.14	1.22	7.0
Overall	1.15	1.41	22.6

* Annual crude properties from EIA's Petroleum Supply Annual 1996 and 2002

We next used published information to estimate how changes in crude oil sulfur content would impact the sulfur level of unhydrotreated distillate blendstocks.[AA] Table 7.2.1-22 depicts estimated sulfur contents for straight run distillate for a variety of crude oils containing both 1.15 and 1.41 weight percent sulfur.

Table 7.2.1-22
Straight Run Middle Distillate Sulfur Content (ppm) *

Crude Oil Sulfur Content	Sweet U.S. Crude Oil	West Texas Crude Oil	California Crude Oil	Middle East Crude Oil	Venezuelan Crude Oil	Average of All Crude Oils
1.15 wt %	4400	6400	7800	4500	3500	5330
1.41 wt %	5400	7800	9800	5300	4400	6540
Change in Distillate Sulfur	22.7%	21.9%	25.6%	17.7%	25.7%	22.7%

* Middle distillate assumed to have mid-boiling point of 500 F.

As can be seen, the 22.6 percent increase in crude oil sulfur content is estimated to increase the sulfur content of straight run distillate by 17.7-25.7 percent, with an average increase of 22.7 percent. Thus, on average, the sulfur content of straight run distillate increases to essentially the same degree as that of the crude oil. Therefore, it is reasonable to assume that the increases in crude oil sulfur content shown in Table 7.2.1-21 above increased the sulfur content of straight run distillate proportionally. In addition, we assume that the sulfur content of the other blendstocks, namely LCO and other cracked stocks, also increased to the same degree.

As discussed in Section 7.1 above, the average sulfur content of high sulfur distillate does not appear to have changed substantially since 1996. A significant portion of this distillate is

[AA] Petroleum Refining Fourth Edition, Gary Handewerk, 2001, pages 41 to 45.

produced by refineries without distillate hydrotreating, where an increase in crude oil sulfur would by necessity have been reflected in their distillate production. This implies that the increases in crude oil sulfur content occurred primarily at refineries with distillate hydrotreating capacity. To account for this, we adjusted the changes in crude oil sulfur shown for the percentage of high sulfur distillate produced by refiners with hydrotreaters. For example, crude oil sulfur in PADD 2 increased by 21.3 percent. Of all the distillate produced in PADD 2, 70 percent was produced by refineries with distillate hydrotreaters. Therefore, if the crude oil sulfur at the refineries producing the other 30 percent of high sulfur distillate did not change, the crude oil sulfur at refineries with hydrotreaters increased by 30 percent (21.3/0.7). The results for all five PADDs are shown in Table 7.2.1-23 below.

Table 7.2.1-23
Quality of High Sulfur Distillate from Non-California Refineries: 2002 and Beyond

	PADD				
	1	2	3	4	5
High Sulfur Distillate Pool					
Sulfur content (ppm)	2925	2973	3776	2549	2566
% Hydrotreated	20	41	58	21	83
High Sulfur Distillate Produced by Refineries with Hydrotreaters					
Increase in crude oil sulfur content	-11%	30%	37%	17%	15%
% of high sulfur distillate pool	81	70	95	40	48
% Hydrotreated	25	58	61	52	17
Sulfur content of portion not hydrotreated (ppm)	3771	6623	9248	4964	3034

The next step was to increase the sulfur content of the unhydrotreated distillate at refineries with hydrotreaters by the same percentage that crude oil sulfur increased. For example, in PADD 2, the sulfur content of 5081 ppm was increased by 30 percent to yield a final non-hydrotreated distillate sulfur content of 6623 ppm. The sulfur content of the 2002 high sulfur distillate is the same as that shown in Table 7.2.1-23 and the sulfur content of the hydrotreated distillate is 340 ppm. Therefore, the percentage of high sulfur distillate at these refineries which is hydrotreated can be calculated. For example, in PADD 2, a mix of 42 percent hydrotreated distillate at 340 ppm and 58 percent unhydrotreated distillate at 6623 produces a pool of high sulfur distillate at 2973 ppm. Finally, given the percent of all high sulfur distillate being produced by refineries with hydrotreaters (for PADD 2, 70 percent), the portion of the entire high sulfur distillate pool which is hydrotreated can be calculated. For example, for PADD 2, the portion of the entire high sulfur distillate pool which is hydrotreated is 41 percent, the product of the the percent of all high sulfur distillate being produced by refineries with hydrotreaters (70 percent) and the hydrotreated percentage of high sulfur distillate at those refineries with hydrotreaters (58 percent). These figures are summarized in Table 7.2.1-23 above.

High sulfur distillate produced by refineries without hydrotreaters is assumed to have sulfur contents equal to the average high sulfur distillate produced in that PADD. High sulfur distillate produced by refineries with hydrotreaters is a mix of unhydrotreated blendstocks at the sulfur levels shown in Table 7.2.1-23 and hydrotreated blendstock containing 340 ppm sulfur. The average sulfur content of this distillate is also the average sulfur content of the high sulfur distillate produced in that PADD. We assume that these hydrotreated percentages and sulfur contents remain constant beyond 2002.

A comparison of the hydrotreated portion of all high sulfur distillate in 1996 (Table 7.2.1-20) and 2002 (Table 7.2.1-23) shows that except in PADD 1, we are projecting that a significant increase in the degree of hydrotreating has occurred. This implies that refiners built new hydrotreaters or expanded existing hydrotreaters during this time period. We desired to confirm that this in fact occured. The first step in this confirmation was to estimate the increased capacity of distillate hydrotreating. The second step was to show that this increase was sufficient to provide for the increased production of highway diesel fuel, as well as the increase in the hydrotreated percentage of high sulfur distillate.

Table 7.2.1-24 presents hydrotreating and hydrocracking capacity at U.S. refineries located outside of California in 1996 and 2002, according to EIA's Petroleum Supply Annual reports from these two years (assuming an annual average utilization rate of 90 percent). Both processes produce distillate blendstocks which likely meet the 500 ppm highway fuel cap and which have had their olefins and some aromatics removed, reducing the cost of further hydrotreating. As described above, hydrocrackers are assumed to convert roughly 21 percent of their feed to distillate.

Table 7.2.1-24
Effective Non-California Distillate Hydrotreating and Hydrocracker Capacity 1996 to 2002

	Distillate Hydrotreating	Hydrocrackers
1996 Capacity	3,108,285	834,651
2002 Capacity	3,380,323	1,003,050
Increase in capacity	272,038	168,399
Increase in low sulfur distillate	272,038	35,869*

* 90 percent of rated capacity. Hydrocrackers assumed to convert 21 percent of feedstock to distillate.

As can be seen, the total capacities of both processes increased substantially. In total, these capacity expansions increased the production capacity of low sulfur distillate by 307,900 barrels per day.

Table 7.2.1-25 shows the distillate fuel production in 1996 and 2002, again from EIA's Petroleum Supply Annual reports. We show the production of jet fuel and kerosene, since much of the volume of these No. 1 distillate fuels is also hydrotreated and the above distillate hydrotreating capacities do not distinguish between No. 1 and No. 2 distillates.

Table 7.2.1-25
Non-California Distillate Production (BPD)

	Jet Fuel and Kerosene *	Highway Diesel Fuel	High Sulfur Distillate
1996	1,577,000	1,842,797	1,213,490
2002	1,571,000	2,298,507	964,184
Increase	-6,000	455,710	-249,307

* Jet fuel includes production from California refineries.

As can be seen, the production of jet fuel and kerosene was essentially constant in 1996 and 2002. Thus, we assume that no additional hydrotreating capacity was used in the production of jet fuel and kerosene in 2002 versus 1996. It is possible that the increased sulfur content of crude oil occurring over this 6 year period caused refiners to increase a greater percentage of the No. 1 distillate blendstocks used to produce these two fuels. However, no data are available to estimate this effect. Since the sulfur standards for these No.1 distillate fuels are not stringent, the overall change in hydrotreating should be small.

As also shown in Table 7.2.1-25, the production of highway diesel fuel increased by nearly 25 percent, while the production of high sulfur distillate decreased by 20 percent. As described above, the hydrotreated fraction of highway fuel was 83.8 percent in 1996. Thus, the production of 455,710 barrels per day more highway diesel fuel likely utilized 382,000 (455,710 * 0.838) barrels per day of effective hydrotreating or hydrocracking capacity. However, as discussed below, crude oil sulfur levels increased between 1996 and 2002 by nearly 20 percent. Thus, to be conservative, we will also consider the possibility that 100 percent of this additional production of highway diesel fuel was hydrotreated. Thus, we estimate that the production of 455,710 barrels per day more highway diesel fuel might have utilized as much as 455,710 barrels per day of effective hydrotreating or hydrocracking capacity. Combining these two estimates to produce a range, the additional production of highway diesel fuel utilized 74,100-147,810 more barrels per day of effective hydrotreating and hydrocracking capacity than the 307,000 barrels per day of effective capacity which was added between 1996 and 2002.

Regarding the production of high sulfur distillate, two factors changed, volume and percentage which was hydrotreated. In 1996, 1.213 million BPD of high sulfur distillate was produced, 34 percent of which was hydrotreated. In 2002, 0.964 million BPD of high sulfur distillate was produced, 41 percent of which was hydrotreated. This implies a net reduction of hydrotreated volume of 20,300 BPD. This provides some but not all of the hydrotreating capacity needed to produce the additional highway fuel. The shortfall ranges from 53,800-127,510 barrels per day of effective hydrotreating capacity.

We believe that this remaining hydrotreating capacity needed to produce the additional highway diesel fuel likely came from an increase in the utilization of hydrotreating capacity between 1996 and 2002. The API/NPRA survey showed that only 78 percent of the total rated hydrotreating capacity was utilized in 1996. We believe that full utilization can be closer to 90 percent. (Crude oil utilization rates today are over 95 percent.) A 12 percent increase in the utilization rate of hydrotreating capacity in 1996 would be 373,000 barrel per day. This far exceeds the 53,800-127,510 barrel per day shortfall estimated above. Thus, we conclude that the increase in overall hydrotreating percentage of high sulfur distillate are reasonable.

7.2.1.3.3 Refinery Specific Distillate Production Volumes

In the NPRM, we projected refinery's volumes of no. 2 distillate fuel in two steps. First, we obtained each refinery's production of no. 2 distillate fuel in 2000 from EIA. (This data is considered confidential and is based on information which refiners are required to submit to EIA periodically.) These production volumes include a breakdown of how much fuel was certified to meet the 500 ppm highway fuel sulfur cap and how much fuel was not so certified. Second, these year 2000 production volumes were increased to represent 2008 production using EIA projections from their 2002 AEO report. We applied separate growth rates for highway diesel fuel and high sulfur distillate. We assumed that refineries would not change their relative production of highway diesel fuel and high sulfur distillate except as reflected in the distinct national average growth projections for the two fuels.

For the final rule, we have made a number of changes to improve this portion of our cost analysis. First, since the NPRM analysis was conducted, we received refiners' projection of the volume of 15 and 500 ppm highway diesel fuel which they plan to produce in 2006-2010. In some cases, these volumes differ significantly from their historic production of highway diesel fuel. Thus, we have incorporated these projections into our projection of refineries' relative production of highway diesel fuel and high sulfur distillate prior to the implementation of this rule. Second, we have shifted our base year for historic production volumes from 2000 to 2002 to reflect more recent data available from EIA. Third, we have shifted the future year for which we project desulfurization costs from 2008 to 2014. Fourth, and finally, we are using EIA projections of distillate production growth from their 2003 AEO report[36], instead of their 2002 AEO report. The methodology for estimating refinery specific production volumes of highway diesel fuel and high sulfur distillate is described in more detail below, as well as the results of this analysis.

As described above, the first step was to estimate each refinery's historic production volumes of highway diesel fuel and high sulfur distillate. Except for using more recent 2002 data from EIA, versus 2000 in the NPRM, this step was identical to that performed in the NPRM analysis.

The second step increased these 2002 production volumes of highway and high sulfur distillate fuel to represent growth through 2014. We chose 2014, because it represents the mid-point of the life of the desulfurization equipment build in response to this rule (per IRS rules, this equipment has a 15 year life). We obtained EIA's projected growth factors for domestic production of these two fuels over this time period, which were consistent with those underlying their 2003 AEO projections. EIA projects that highway fuel production will increase 42.1 percent over this time period, while production of high sulfur distillate will only increase 8.1 percent. Each refinery's 2002 production volumes of these two fuels werw increases by these percentages to represent their likely production in 2014. The sum of the production volumes for the two fuels was taken to be each refinery's total distillate production in 2014. It should be noted that the combination of these two growth rates results in a greater increase in the production of distillate fuel from domestic refineries than indicated by the growth in crude oil consumption by these refineries (typically assumed to be the driver of increased fuel production). This difference occurs because EIA projects that domestic refiners will increasingly process heavy oils in addition to virgin crude oils. This step was analogous to that performed in the NPRM, with the exception that growth was projected to 2014 instead of 2008. The historic and future production volumes by PADD are shown in Table 7.2.1-26.

Table 7.2.1-26
U.S. Distillate Fuel Production: AEO 2003 (BPSD) *

	2002			2014		
	Highway Fuel	High Sulfur Distillate	Total Distillate	Highway Fuel	High Sulfur Distillate	Total Distillate
PADD 1	239,375	223,063	462,438	337,936	241,161	579,098
PADD 2	647,170	159,688	806,858	913,637	172,644	1,086,281
PADD 3	1,245,605	520,142	1,765,747	1,758,473	562,345	2,320,818
PADD 4	129,397	29,973	159,370	182,676	32,404	215,080
PADD 5	396,475	95,775	492,250	559,720	103,546	663,266
Total	2,658,022	1,028,641	3,686,663	3,752,442	1,112,100	4,864,542

* Growth from AEO 2003 Table 17. Includes U.S. Virgin Island refineries.

The third step differed from the NPRM analysis in that we utilized refiners' confidential projections of how they planned to produce highway diesel fuel in 2006-2010 under the upcoming 2007 highway diesel fuel program. Under this program, refiners must submit their projected production volumes of 15 and 500 ppm diesel fuel to EPA every year starting in 2003 (called a pre-compliance report). EPA would then publish aggregated results to help refiners optimize their compliance plans and better ensure sufficient supply of highway diesel fuel under the rule. Shell oil's refinery in Bakersfield, California and Carribean Petroleum's refinery in Puerto Rico were removed from the analysis due to recent shutdowns or plans to shut down.

The highway diesel fuel program begins to take effect in June 2006. Some refiners submitted 2006 production volumes on an annualized basis, while others submitted volumes for just the seven months affected by the program. To avoid these differences, we focused on refiners' projections for 2007, the first full calendar year affected by the program. We assumed these projections, made by refiners, represented the best estimate of future production levels of highway diesel fuel on a refinery-specific basis. While refiners projected their production volumes for highway diesel fuel, they did not have to submit their plans for producing high sulfur distillate. Therefore, we estimated their production of high sulfur distillate subtracting their production of highway diesel fuel from our estimate of the refinery' total production of No. 2 distillate from step two above.

The fourth and final step was to put refiner's projected 2007 highway diesel fuel production volumes on the same basis as these 2014 total distillate volumes in order to back-calculate a high sulfur distillate volume. To do this, we assumed that the refiners' highway pre-compliance reports represented the absolute volumes which they planned to produce in 2007 including any increases in total distillate production which might occur due to refinery debottlenecking, new or expanded heavy oil processing capacity, etc. Using information supplied in a number of these reports, it appeared that some refiners simply estimated their 2007 production volumes by applying some fraction to their historical 2002 production volumes. However, it is possible that other refiners did include such planned capacity increases. Overall, our methodology could under-estimate highway fuel production in 2007 to some degree, but we believe that the degree of this under-estimation should be small. We then increased these 2007 highway fuel production volumes by EIA's projected increase in total domestic highway diesel fuel production between 2007 and 2014, which is 14.5 percent

We then compared the total projected production of highway diesel fuel in 2007 in each PADD to the projected demand for highway diesel fuel developed in section 7.1 above. Again, in both cases, the volumes are representative of those expected for 2014. The highway diesel fuel sulfur standards are those representative of 2007 prior to this NRLM rule. Production and demand for PADDs 1 and 3 were combined, due to the large volume of fuel which PADD 3 refiners ship to PADD 1. The results are shown in Table 7.2.1-27.

Table 7.2.1-27
Projected Production of Highway Fuel in 2007 (Thousand BPD in 2014)

	PADD's 1 & 3	PADD 2	PADD 4	PADD 5
Required Highway Fuel Production *	1,588.3	1,162.4	187.5	530.9
Projected Production: 15 ppm Highway Fuel	1,878.0	914.8	148.4	468.2
Projected Production: 500 ppm Highway Fuel	62.5	49.5	4.1	20.3
Projected Production: All Highway Fuel	1940.5	964.3	152.5	488.5
Shortfall	-352.2	198.1	35.0	42.4
Additional Production of Highway Fuel				
Current highway fuel refiners with excess 500 ppm capacity	0	0	0	2.2 (1)
15 ppm highway fuel produced from high sulfur distillate	0	0	41.8 (4)**	40.5 (4)
Final 15 ppm Highway Fuel Production	1,723.9	914.8	190.2	508.7
Final 500 ppm Highway Fuel Production	62.5	49.5	4.1	22.5
Final Total Highway Fuel Production	1,786.4	964.3	194.3	531.2

* Demand from highway vehicles, spillover of highway fuel to other markets plus highway fuel lost during distribution.
** Number of refineries producing this fuel is shown in parenthesis.

As can be seen, projected 2007 production of highway diesel fuel in PADDs 1 and 3 significantly exceeds projected demand, while the opposite is true in PADDs 2, 4 and 5. PADD 3 refiners currently supply much of PADD 2's diesel fuel consumption. A comparison of current shipments from PADD 3 to PADD 2 shows that these shipments far exceed the 198,000 barrel per day shortfall projected for PADD 2. Therefore, we assumed that PADD 3 refineries would balance demand for highway fuel in PADD 2. However, PADD 3 currently supplies little or no fuel to PADDs 4 and 5. Therefore, we assumed that additional refineries would have to produce highway diesel fuel in 2007 to satisfy demand. A comparison of 2002 production of highway diesel fuel and refiners' projected production in 2007 revealed one refinery in PADD 5 which had excess capacity to produce 500 ppm diesel fuel using its current hydrotreater. Therefore, we assumed that this refinery would likely produce 500 ppm highway diesel fuel in 2007 by purchasing credits from other refiners. We projected that the remaining shortfalls would be made up by refiners constructing new desulfurization capacity to process high sulfur distillate to 15 ppm. We assumed that these refineries would go straight to 15 ppm for two reasons. First, as long as they were investing to produce highway diesel fuel, they would likely design their equipment to meet the 15 ppm cap, which would affect all highway fuel in 2010. Second, whether or not these refiners invested to produce 500 ppm highway diesel fuel in 2006 and revamped this equipment in 2010 to produce 15 ppm highway diesel fuel has no effect on the cost of other refiners producing NRLM fuel under this NRLM fuel rule. It was simpler to assume these refiners invested in one step rather than two.

This left an excess highway fuel production of 154,100 barrels per day in PADDs 1 and 3 beyond that necessary to meet the shortfall in PADD 2. We assumed that refiners would adjust their plans to produce 15 ppm highway diesel fuel in 2007 based on the results of the refiners' pre-compliance reports. Therefore, we assumed that this excess production would not in fact occur. To represent this on a refinery specific basis, we assumed that the refiners estimated to have the highest cost of producing 15 ppm fuel in PADDs 1 and 3 would decide not to produce this fuel until the 154,100 barrel per day excess was eliminated. We also assumed that this excess production capacity would be available to produce 500 ppm NRLM fuel in 2007 with only incremental operation costs, no capital cost. This would be the case for excess 15 ppm fuel capacity deriving from a revamp of an existing hydrotreater. However, it would not be the case for grass roots 15 ppm fuel capacity which never was built. Thus, this assumption might have led to a slight underestimation of the cost of 500 ppm NRLM fuel from 2007-2010. We believe that the degree of this underestimation is small.

Having developed refinery-specific projections of both total and highway distillate production, we assumed that the difference was high sulfur distillate. The resulting total production volumes for 2007 (projected to year 2014) by PADD and for the nation are shown in Table 7.2.1-28.

Table 7.2.1-28
"2007" Refiner's Production of Distillate Fuels (Thousand BPD in 2014) *

PADD	Highway Fuel	High Sulfur Distillate	Total Distillate
1&3	1,786	1,116	2,903
2	964	122	1,086
4	194	21	215
5	531	132	663
Total	3,476	1,391	4,867

* Growth from AEO 2003 Table 17. Includes U.S. Virgin Island refineries.

We repeated this analysis using refiners' projections of their production of highway diesel fuel in 2010. One limitation in doing so is that the refiners' pre-compliance reports for 2010 only apply to the first half of 2010 when they can still use banked credits to produce some 500 ppm highway fuel. We are more interested here in the last half of 2010, when all highway fuel must meet a 15 ppm cap and NRLM fuel will also have to meet a 15 ppm cap under the final NRLM program. To accommodate this difference, we assumed that refiners would simply continue producing 15 ppm fuel at the same rate as they did in the first half of 2010. We also assumed that refiners would convert production of 500 ppm highway fuel to high sulfur distillate starting on June 1, 2010 absent the NRLM fuel standards contained in this rule.

As was done for the 2007 projections, we then increased these 2010 highway fuel production volumes by EIA's projected increase in total domestic highway diesel fuel production between 2010 and 2014, which is 11.0 percent. The results are shown in Table 7.2.1-29 below.

Table 7.2.1-29
Projected Production and Demand for Highway Fuel in 2010 (Thousand BPD in 2014)

	PADD's 1 & 3	PADD 2	PADD 4	PADD 5
Required Highway Fuel Production *	1,651.9	1,205.3	194.2	567.2
Projected 15 ppm Highway Fuel Production	2008.3	959.5	153.7	474.1
Shortfall	-356.4	245.8	40.6	93.2
Additional Production of 15 ppm Highway Fuel				
Produced from high sulfur distillate			41.8 (4) **	93.2 (7)
Final Production of 15 ppm Highway Fuel	1942.4	914.8	195.5	567.3

* Demand from highway vehicles, spillover of highway fuel to other markets plus highway fuel lost during distribution.
** Number of refineries producing this fuel is shown in parenthesis.

As for 2007, the projected volume of highway diesel fuel in 2010 by PADD 1 and 3 refiners exceeds projected demand (plus downgrades in the distribution system), while those of the other PADDs are less than projected demand. In PADDs 4 and 5, we again assumed that additional refineries would produce 15 ppm highway diesel fuel from their high sulfur distillate. The number of PADD 4 refiners was the same as in 2007. In PADD 5, seven additional refineries were assumed to produce 15 ppm highway diesel fuel, three more than in 2007.

PADD 2's shortfall was again assumed to be supplied from PADD 3. Again, we assumed that a number of PADD 1 and 3 refiners would decide not to produce 15 ppm highway fuel so that these PADD's production would match demand, after supplanting PADD 2's supply. In doing this, we also assumed that one PADD 2 refinery would decide not to produce 15 ppm highway fuel due its much higher desulfurization costs compared to other PADD 2 refineries and PADD 3 refineries able to supply that area via pipeline transport.

Having the refinery-specific projections of both total and highway distillate production, we assumed that the difference was high sulfur distillate. The resulting total production volumes for 2010 (grown to year 2014) by PADD and for the nation are shown in Table 7.2.1-30 below.

Table 7.2.1-30
"2010" Refiner's Production of Distillate Fuels Projected (Thousand BPD in 2014)

	Highway Fuel	High Sulfur Distillate	Total Distillate
PADD's 1&3	1,942	960	2,903
PADD 2	915	172	1,086
PADD 4	196	20	215
PADD 5	567	96	663
Total	3,620	1,247	4,867

* Growth from AEO 2003 Table 17. Includes U.S. Virgin Island refineries.

Note that we made no changes in the production volumes of distillate fuel to account for any reduction in wintertime blending of kerosene that might occur as a result of the 15 ppm highway or NRLM sulfur caps. Kerosene added to 15 ppm diesel fuel must itself meet a 15 ppm sulfur. Sometimes, kerosene is added at the refinery and the winterized diesel fuel is sold or shipped directly from the refinery. At other times, the kerosene blending is done at the terminal, downstream of the refinery. The former approach may mean adding kerosene to more diesel fuel than actually requires it. The latter approach requires that a distinct 15 ppm kerosene grade be produced and distributed. Much of this 15 ppm kerosene might be used in applications not requiring 15 ppm sulfur content. Adding pour point depressant is an alternative to blending kerosene. This can be done very flexibly at the terminals in areas facing very cold weather. Thus, we expect that the use of pour point depressants will increase and the terminal blending of kerosene will decrease. For kerosene blended into winter diesel fuel, the kerosene can simply be added to the distillate being fed to the hydrotreater and desulfurized along with the rest of the 15 ppm diesel fuel pool.

In summary, the primary purpose of developing these future production volumes is to reasonably project the economies of scale of the desulfurization equipment being constructed in response to the NRLM fuel program, including the interaction of this program with the 2007 highway fuel program. Larger capacity equipment costs more than smaller equipment in total, but is less expensive on a per gallon basis. Operating costs are not affected, as these are proportional to volume. In the NPRM we projected production volumes for calendar year 2008, as this was the first full year that the NRLM sulfur caps were effective. However, we now believe that 2014 is more reasonable, because the assumed life of desulfurization equipment is 15 years and 2014 marks the mid-point of the life of equipment built in 2007.

7.2.1.3.4 Selection of Refineries Producing 500 and 15 ppm NRLM Fuel

We used two basic criteria to select those refineries most likely to produce 500 and 15 ppm NRLM fuel under this NRLM rule. The first criterion was refineries' ability to avoid producing lower sulfur NRLM fuel (i.e., continue producing high sulfur heating oil). The second criterion was the estimated cost of compliance. We assumed that those refineries facing the lowest desulfurization costs in a given region would be the most likely to invest. A key factor in estimating desulfurization costs on a refinery specific basis is whether the refinery: 1) would be able to produce 500 or 15 ppm NRLM fuel with its existing hydrotreater, 2) would be able to revamp an existing hydrotreater to produce NRLM fuel, or 3) would have to build a grass roots hydrotreater to produce NRLM fuel. These three factors are described below.

7.2.1.3.4.1 Geographic and Logistic Limitations Affecting the Production of Heating Oil

It goes without saying that refiners have to be able to market the fuels which they produce. That is the nature of business. This includes the No. 2 distillate that they produce. Most No. 2 distillate volume comes directly from the crude oil itself. It is not feasible, or economical, to convert all this distillate fuel to other products. Thus, under this NRLM rule, refiners basically have three choices for this distillate; produce 15 ppm highway diesel fuel, produce 500 and 15 ppm NRLM fuel (depending on the time period) or produce high sulfur heating oil. Producing high sulfur heating oil should require no change in current refinery configurations, as all of the No. 2 distillate produced today essentially meets heating oil specifications.

However, as alluded to above, refiners must be able to deliver their fuel to the geographical market where it is consumed. The market for high sulfur distillate will decrease by 50 percent upon the implementation of this NRLM rule. Over two-thirds of all high sulfur distillate use after 2010 will be concentrated in the Northeast. Thus, PADD 1 refineries should have no difficulty in selling high-sulfur distillate to this market if they desired. Likewise, PADD 3 refineries which are connected to one of the two large pipelines running from the Gulf Coast to the Northeast (Plantation and Colonial) or which have access to ocean transport should also be able to market high sulfur distillate. In addition, selected markets in PADD 5, such as Hawaii, also have significant heating oil demand, so some PADD 5 refineries were also assumed to have the flexibility to continue producing high-sulfur distillate if they desired.

As discussed in Section 7.1 above, however, the heating oil markets in PADDs 2 and 4 will be very small after the NRLM rule takes effect. Thus, we believe that it is unlikely that pipelines in these PADDs will continue to carry heating oil as a fungible product. Therefore, we do not believe that refineries located in PADDs 2 and 4 will have the option of choosing to avoid complying with the NRLM fuel program by producing high sulfur distillate. To the degree that they are not already producing 15 ppm highway diesel fuel, they will have to take steps to produce 500 ppm and 15 ppm NRLM fuel. The same is true for refineries located in PADDs 3 and 5 which do not have access to a large local market for heating oil or which are not connected to efficient transport to the Northeast. The final NRLM rule does not require that these refineries produce NRLM fuel, *per se.* We simply believe that this is a reasonable assumption for cost-estimation purposes.

We reviewed the geographical location of each domestic refinery and those of pipelines serving the Northeast and identified those falling into the two groups described above. The number of refineries projected to have no choice but to produce NRLM diesel fuel is shown in

Table 7.2.1-31 along with the total number of refineries projected to produce high-sulfur distillate fuel after implementation of the 2007 highway diesel rule. These projections consider the small refiner provisions included in the NRLM final rule. These provisions reduce the number of refineries projected to have to produce 500 ppm NRLM fuel in 2007, as small refiners are assumed to be able to sell high sulfur diesel fuel to the NRLM market.

Table 7.2.1-31
Number of Refineries Lacking the Option to Produce Heating Oil

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Prior to NRLM Rule Implementation considering Fully Implemented Highway Diesel Program					
Refineries Producing Some High-Sulfur Distillate Fuel	13	17	37	8	17
Starting June 1, 2007 (Considers Small Refiner Provisions)					
Must produce 500 NRLM fuel	0	14	4	7	0
Refineries Producing Some High-Sulfur Distillate Fuel	13	3	33	1	17
Starting June 1, 2010 (Considers Small Refiner Provisions)					
Must produce 15 Nonroad fuel	0	6	0	3	0
Must produce 500 NRLM fuel	1	11	9	5	5
Refineries Producing Some High-Sulfur Distillate Fuel	12	0	28	0	12
Starting June 1, 2012 (Considers Small Refiner Provisions)					
Must produce 15 NRLM fuel	0	14	4	7	0
Must produce 500 NRLM fuel	1	3	5	1	5
Refineries Producing Some High-Sulfur Distillate Fuel	12	0	28	0	12

We repeated this analysis for 2010. The number of refineries producing some high sulfur distillate fuel in 2010 is less than in 2007, as additional refineries produce either 15 or 500 ppm NRLM fuel. The number of refineries projected to have to produce NRLM fuel in 2010 due to distribution system constraints increases over that in 2007 due to the expiration of the small refiner provisions. While we project that the vast majority of 15 ppm nonroad fuel will be produced by those refineries facing the lowest desulfurization costs, we project that a few refineries will have to invest to produce 15 ppm nonroad fuel because of limited ability to distribute higher sulfur fuel to the L&M and heating oil markets. These refineries produce a large volume of 500 ppm NRLM fuel in 2007 and are not directly connected to a pipeline or navigable waterway. Given the volume of fuel involved, we decided that shipping all of it via rail was also not economically feasible long term. The number of these constrained refineries is much fewer than those which we project will be unable to distribute all of their distillate fuel to the heating oil market and thus had to produce make 500 ppm NRLM fuel in 2007.

In 2012, the number of refineries that must produce NRLM fuel is the same as 2010. However in 2012, the non-small refineries that we project have to produce 500 ppm L&M fuel in 2010 invest further to produce 15 ppm L&M fuel.

In 2014, the only change is the expiration of the small refiner provisions. The small refineries producing 500 ppm nonroad fuel in 2012 invest to produce 15 ppm NRLM fuel. The refinery estimates for years 2007-2012 are shown in Table 7.2.1-31.

Table 7.2.1-32 shows how the NRLM fuel volume produced by these refineries compares with the total required NRLM fuel production volume during the 2007-2010 period. This table starts with the total demand for NRLM fuel, as well as the volume of highway fuel used in the NRLM fuel markets as developed in Section 7.1. Table 7.2.1-32 also shows the volume of high sulfur distillate projected for small refiners which are able to sell high sulfur diesel fuel to the NRLM market during this period. Subtracting the volumes of highway spillover and small refiner fuel from total demand results in the net volume of 500 ppm NRLM fuel which needs to be produced in response to this NRLM rule. The 500 ppm fuel volumes from refineries having to produce this fuel are then shown, along with any remaining volume. It should be noted that we have excluded demand for NRLM fuel in California from Table 7.2.1-32 and the analogous tables for 2010, 2012 and 2014. Nonroad fuel sold in California is already required to meet a 15 ppm cap in this timeframe per State regulation. L&M fuel demand in California is totally satisfied by spillover of highway fuel and downgrade. Thus, we project no on-purpose production of L&M fuel for use in California. However, distillate production from two California refineries which current produce high sulfur distillate fuel is considered in satisfying NRLM fuel demand in PADD 5.

Table 7.2.1-32
500 ppm NRLM Fuel Production: 2007-2010 (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total NRLM Fuel Demand	9,034	7,111	1,046	1,159	18,350
Highway Fuel Spillover	898	1,906	580	381	3,765
Fuel Produced Under Small Refiner Provisions	671	139	5	165	980
NRLM Requiring Desulfurization	7,465	5,066	461	613	13,605
Refineries Having to Produce 500 ppm NRLM Fuel	281	2,549	303	0	3,133
Remaining Production of 500 ppm NRLM Diesel Fuel	7,184	2,517	158	613	10,472

* Excludes NRLM fuel demand in California.

As can be seen, more than enough 500 ppm fuel will be produced in PADDs 2 and 4 by refineries having to produce this fuel. This is a direct result of assuming that no refinery in either of these PADDs will be able to market all of their current high sulfur distillate fuel solely as heating oil. Significant volumes of 500 ppm NRLM fuel will still have to be produced by PADD 1, 3 and 5 refineries. As discussed above, we assume that the refineries facing the lowest desulfurization costs in each PADD will choose to invest to produce any remaining fuel demand in that PADD.

It should be noted that we evaluated small refiners' ability to distribute their production volume of high-sulfur NRLM diesel fuel, even if they do not have access to a common carrier pipelines carrying this fuel. Starting with the total demand for NRLM diesel fuel in each PADD in 2014 from Section 7.1 above, we divided this demand by the square mileage of each PADD to estimate NRLM diesel fuel demand per square mile. We then determined the area over which each small refiner would have to distribute its high-sulfur NRLM fuel to maintain its current high sulfur distillate production level. In all cases, assuming a circular shaped area, the radius of the circle was 100 miles or less. As this is easily within trucking distance, we concluded that it was reasonable to assume that all small refiners can continue selling all their high-sulfur distillate fuel as either high-sulfur distillate fuel or heating oil, and delay producing any 500 ppm NRLM diesel fuel until at least 2010.

Table 7.2.1-33 presents the same breakdown of nonroad fuel supply for the period 2010-2012, with the implementation of the 15 ppm cap. Just over 20% of nonroad fuel demand is satisfied by highway spillover and just under 10% by distribution downgrade. Small refiner 500 ppm fuel supplies roughly 5% of the market, with the remainder being new 15 ppm fuel production. Less than 10% of the new 15 ppm nonroad fuel production is by refineries having no economic choice but to do so, the vast majority of 15 ppm nonroad fuel is produced by refineries with the lowest cost of production. The volume of 15 ppm nonroad fuel that has to be produced by refineries with no other economic choice is significantly than was the case for 500 ppm NRLM fuel in 2007. This occurs, because the L&M market is much larger than the heating oil market in PADDs 2, 4 and 5 and most refineries can ship their fuel via pipeline or waterway to the L&M market.

Table 7.2.1-33
15 ppm Nonroad Fuel Production: 2010-2012 (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total Nonroad Fuel Demand	5901	5,670	810	934	13,315
Highway Spillover	551	1,535	451	341	2,878
Distribution Downgrade	217	519	111	264	1,111
Small Refiner Volume (500 ppm nonroad fuel)	419	139	5	165	728
New Production of 15 ppm Nonroad Fuel	4,714	3,477	243	164	8,598
Refineries Having to Produce 15 ppm Nonroad Fuel	0	631	157	0	728
Remaining Production of 15 ppm Nonroad Fuel	4,714	2,846	86	164	7,810

* Excludes NRLM fuel demand in California.

Table 7.2.1-34 presents the same breakdown of L&M fuel supply for the period 2010-2012. Just under 20% of nonroad fuel demand is satisfied by highway spillover and another 20% by distribution downgrade. We project that small refiner 500 ppm fuel will be used in the nonroad fuel market, where it has an economic advantage. Distribution of this fuel should be economically feasible, given the small volumes involved and the ubiquitous nature of the nonroad fuel market. Thus, no L&M fuel is supplied by small refiners during this time frame. Thus, roughly 60% of 500 ppm L&M fuel is being produced for the L&M market. Nearly 80% of this 500 ppm L&M fuel production is by refineries which are unable to economically distribute heating oil, so they have to produce a lower sulfur fuel. In PADDs 2 and 4, the volume of 500 ppm fuel produced by refineries with no other economic choice is greater than the remaining demand for L&M fuel. We assumed that the excess production of 500 ppm fuel refineries in the eastern and southern regions of PADD 2 could be satisfy L&M demand in PADDs 1 and 3, respectively. This still leaves a significant volume of 500 ppm L&M fuel needing to be produced by refineries in PADDs 1 and 3. We assumed that excess 500 ppm fuel in PADD 4 would be used in the heating oil market. As usual, we assumed that refineries with the lowest desulfurization costs in PADDs 1,3 and 5 would invest to produce the remaining 500 ppm fuel demand.

Table 7.2.1-34
500 ppm NRLM Fuel Production: 2010-2012 (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total L&M Fuel Demand	3,133	1,441	236	224	5,034
Highway Fuel Spillover	347	371	129	50	897
Distribution Downgrade	866	134	33	40	1,073
NRLM Requiring Desulfurization	1,920	936	74	134	3,064
Refineries Having to Produce 500 ppm L&M Fuel	281	1,918	153	0	2,352
Remaining Production of 500 ppm NRLM Diesel Fuel	1,639	(982)	(79)	134	712
500 ppm Nonroad Fuel Produced by Small Refiners	419	139	5	165	728
Total New 500 ppm Production	2,058	(843)	(74)	299	1,440

* Excludes NRLM fuel demand in California.

Table 7.2.1-35 presents the same breakdown of 15 ppm NRLM fuel volumes for the period 2012-2014 when the L&M standard goes to 15 ppm.

Table 7.2.1-35
15 ppm NRLM Fuel Production: 2012-2014 (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total NRLM Fuel Demand	9,034	7,111	1,046	1,159	18,350
Highway Spillover	898	1,906	579	390	3,773
Distribution Downgrade	467	685	147	304	1,603
Fuel Produced Under Small Refiner Provisions	419	139	5	165	728
Production of 15 ppm NRLM Fuel	7,250	4,381	316	300	12,247
Refineries Having to Produce 15 ppm NRLM Fuel	281	2,549	310	0	3,140
Remaining Production of 15 ppm NRLM Fuel	6,969	1,832	6	300	9,107

* Excludes NRLM fuel demand in California.

Finally, Table 7.2.1-36 presents the same breakdown of 15 ppm NRLM fuel volumes for the 2014 and beyond. The required production volumes of 15 ppm NRLM fuel in 2014 are larger than those in 2012, as the small refiner provisions expire and downgraded 15 ppm fuel can no longer be sold to the nonroad fuel market.

Table 7.2.1-36
15 ppm Nonroad Fuel Production: 2014 and Beyond (million gallons per year in 2014) *

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
Total NRLM Fuel Demand	9,034	7,111	1,046	1,159	18,350
Highway Spillover	898	1,906	579	390	3,773
Downgraded "500 ppm" NRLM Fuel	467	685	146	246	1,544
Fuel Produced Under Small Refiner Provisions	0	0	0	0	0
New Volume of 15 ppm Nonroad Fuel	7,668	4,520	321	523	13,032
Refineries Having to Produce 15 ppm NRLM Fuel	701	2,688	315	165	3,869
Remaining Production of 15 ppm NRLM Fuel	6,967	1,832	6	358	9,163

* Excludes NRLM fuel demand in California.

Sensitivity Case: Long-Term 500 ppm NRLM cap. Table 7.2.1-37 presents an analogous set of 500 ppm NRLM production volumes for 2010 assuming that no 15 ppm NRLM fuel cap was implemented. (This situation is analyzed to allow the long-term analysis of the 500 ppm NRLM diesel fuel cap independent of the 15 ppm nonroad diesel fuel cap). The primary difference between these volumes and those for 2007 above is the absence of the small-refiner volume and fuel to the NRLM pool from distribution downgrade.

Table 7.2.1-37
500 ppm NRLM Fuel Production: 2010 and beyond* (million gallons per year in 2014)

	PADDs 1 & 3	PADD 2	PADD 4	PADD 5	U.S.
NRLM Diesel Fuel Demand	9,034	7,111	1,046	1,159	18,350
Distribution Downgrade	1,084	685	147	304	2,220
Highway Spillover	898	1,906	579	390	3,773
Base High-Sulfur NRLM Demand	7,052	4,520	320	465	12,357
Fuel Produced Under Small Refiner Provisions	0	0	0	0	0
Volume Having to Produce 500 ppm NRLM Fuel	701	2,688	315	165	3,869
Remaining Demand for 500 ppm NRLM Diesel Fuel	6,351	1,832	5	300	8,488

[a] After all small refiner provisions have expired.

Sensitivity Case: 15 ppm Nonroad and 500 ppm L&M Fuel

This case examines the proposed fuel control program, which is identical to that being promulgated, except that locomotive and marine fuel remains at 500 ppm indefinitely. The only difference in the geographical constraints assumed to exist is that PADD 2 refiners were allowed to continue producing 500 ppm locomotive and marine fuel in 2010 and beyond. The result was that some 15 ppm nonroad fuel being consumed in PADD 2 is being produced in PADD 3. This shipment of 15 ppm fuel from PADD 3 to PADD 2 occurs under the final NRLM fuel program, as well.

7.2.1.3.4.2 Low Sulfur NRLM Fuel Via Existing, Revamped or Grass Roots Hydrotreater

This section presents the methodology that we used to determine what actions refiners would likely take to produce 500 and 15 ppm NRLM diesel fuel during the implementation of the NRLM diesel fuel program. The timing of the various steps in both the highway and NRLM fuel programs are summarized in Table 7.2.1-38.

Table 7.2.1-38
Sequence of Sulfur Caps for Highway and NRLM Fuel

	Highway Fuel	Non-Small Refiners		Small Refiners
		Nonroad Fuel	L&M Fuel	
June 1, 2006 - May 31, 2007	80 vol% 15 ppm 20 vol% 500 ppm	High Sulfur	High Sulfur	High Sulfur
June 1, 2007- May 31, 2010	80 vol% 15 ppm 20 vol% 500 ppm	500 ppm	500 ppm	High Sulfur
June 1, 2010 - May 31, 2012	15 ppm	15 ppm	500 ppm	500 ppm
June 1, 2012 - May 31, 2014	15 ppm	15 ppm	15 ppm	500 ppm
June 1, 2014 and beyond	15 ppm	15 ppm	15 ppm	15 ppm

In Section 7.2.1.3.3, we describe how we coupled refiners' projected highway fuel volumes with historic total distillate production fuel volumes and EIA future growth rates for highway and high sulfur distillate fuels to project each refinery's production of highway and high sulfur distillate fuel prior to this NRLM fuel program. The issue in this section is the steps which refiners have to take to produce 15 and 500 ppm NRLM fuel beyond this baseline to comply with the NRLM standards. The primary question answered in this section is whether they will be able to revamp an existing hydrotreater, or must build a new hydrotreater. For 15 ppm highway fuel, we basically assumed, as we did in the Final RIA for the 2007 highway fuel program, that 80 percent of 15 ppm highway fuel volume would be produced using revamped hydrotreaters. The remaining 20 percent would be produced with new, grass-roots units. The remainder of this section develops analogous projections for the production of 500 ppm and 15 ppm NRLM fuel during the various steps of the NRLM fuel program.

To facilitate this discussion, we divided refineries which are projected to produce some high sulfur distillate after 2010 into three categories:

1) "Highway" refineries: refineries which produce 95 percent or more of their total distillate production as 15 ppm highway diesel fuel;[BB]
2) "High Sulfur" refineries: refineries which produce 90 percent or more of their total distillate production as high sulfur distillate;
3) "Mix" refineries: refineries which produce some high sulfur distillate and which do not fall into categories one or two above.

Table 7.2.1-39 presents the percentages of high-sulfur distillate fuel production that falls in the categories described above. The number of refineries in each category is further broken down as to whether or not it currently has a distillate hydrotreater. This latter aspect is relevant to desulfurization costs as discussed in Section 7.2.1.3.2 above.

Table 7.2.1-39
Distribution of High-Sulfur Distillate Production (%) [a]

	High-Sulfur Refineries		Mixed Refineries Producing 15 ppm Highway Fuel in 2006		Mixed Refineries Producing 15 ppm Highway in 2010		Highway Refineries	
	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT	W/Dist HT	No Dist HT
Number of Refineries	10	25	37	11	1	0	7	1
Percent of Nonroad Fuel	31	15	38	14	1	0	1	0

[a] " W/Dist HT" means refineries currently having a distillate hydrotreater
"No Dist HT means refineries that do not currently have a distillate hydrotreater

The next three sub-sections address how we project that each of these groups of refineries could produce either 500 or 15 ppm NRLM fuel. The final sub-section summarizes the results.

Highway Refineries: This category primarily includes refineries which are projected to produce 95 percent or more of their the No. 2 distillate fuel in 2010 to the 15 ppm highway standard prior to this NRLM rule. Refineries producing 100 percent highway fuel have no distillate fuel left from which to produce 500 or 15 ppm NRLM fuel. Thus, with one exception, they are ignored in this analysis. The exception is that the refiners' pre-compliance reports showed an excess supply of 15 ppm highway fuel in PADDs 1 and 3. Production of NRLM fuel by highway refineries presumed to supply this excess is addressed slightly differently below.

Refineries in this category produce a very small amount of high-sulfur distillate fuel compared with their volume of highway diesel fuel. This small volume of high-sulfur distillate fuel is likely either off-specification diesel fuel or opportunistic sales to the non-highway diesel

[BB] We also included a few refineries which project producing 15 ppm highway fuel in 2010, but whose highway fuel is not needed to fulfill highway fuel demand in 2010.

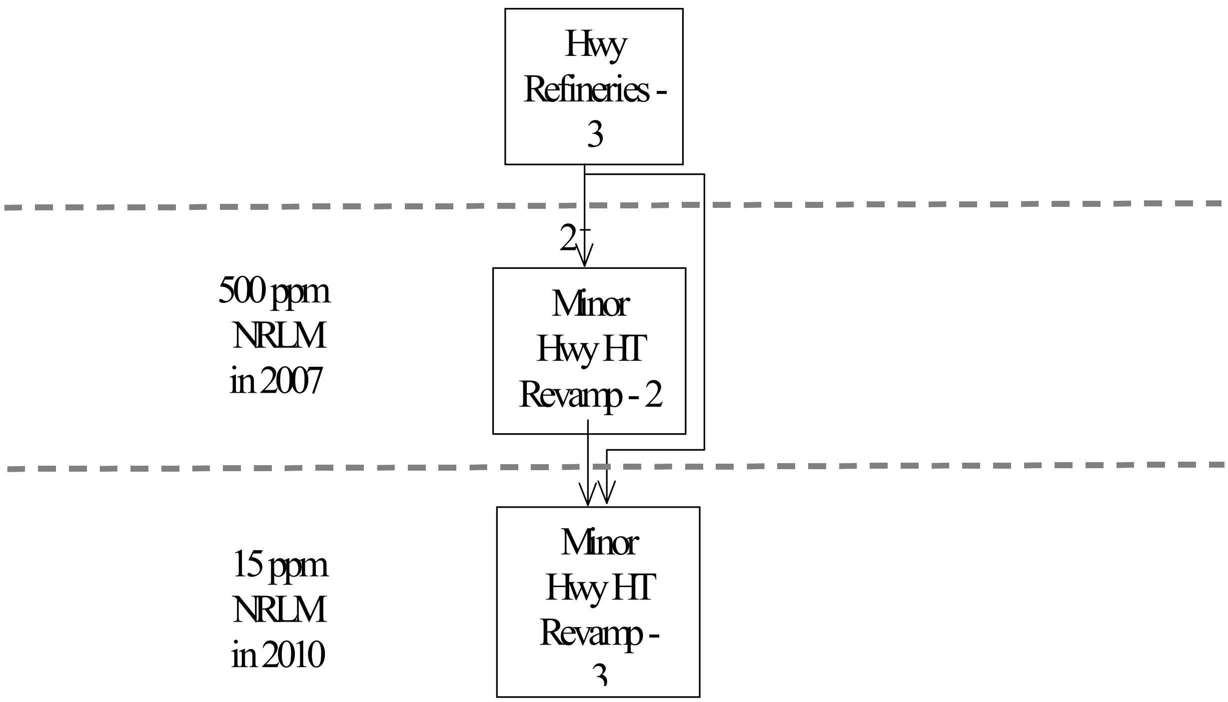
fuel market because of advantageous prices, market relationships, etc. Thus, we assumed that the refinery could incorporate this high-sulfur distillate into its highway hydrotreater design. The incremental capital cost assigned to the NRLM diesel fuel program was assumed to be the difference between the capital cost associated with a grass-roots hydrotreater sized to process all the refinery's distillate fuel and that for a grass-roots hydrotreater sized to treat just the highway diesel fuel volume. Thus, this approach assumed that the incremental cost of this small increase in capacity could occur at a high degree of economy of scale, but would also encompass the full cost of hydrotreating from uncontrolled levels to 7 ppm. We did this because it seems reasonable to assume that a refinery producing so much highway fuel would design its 15 ppm hydrotreater in such a way that it could be modified to process all the refinery's distillate. This is particularly true given the public attention given to the need for 15 ppm nonroad diesel fuel over the past few years.

This approach is applied to both the production of 500 and 15 ppm NRLM fuel. While incorporating the production of 500 ppm NRLM fuel into a 15 ppm highway fuel hydrotreater is not necessarily straightforward, the net effect of our assumption here is that roughly half the capital cost to produce 15 ppm NRLM fuel at these refineries is required to produce 500 ppm NRLM fuel. This seems reasonable. Also, this assumption only affects capital costs, not operating costs, as the latter are only a function of the distillate composition and refinery location (i.e., PADD).

As described in Section 7.2.1.3.3 above, the highway pre-compliance reports showed that an excess of 15 ppm fuel capacity was likely in PADD 3 in 2007. Thus, we assumed that this capacity could supply 500 ppm NRLM to PADDs 1, 2 and 3 through 2010 at a relatively low cost. To approximate these "low" costs we assumed that 500 ppm NRLM fuel could be produced by these hydrotreaters at the national average cost of the remainder of the 500 ppm NRLM fuel.

Figure 7.2-6 presents a flowchart of this process for highway refineries.

Figure 7.2-6
"Highway" Refineries NRLM Hydrotreater Modifications



HT = Hydrotreater
Hwy = Highway
Number in box equals number of refineries.

Mix Refineries: Mix refineries produce substantial volumes of both highway and high sulfur distillate fuels prior to the NRLM rule. Because of the substantial volumes of both fuels being produced, we assumed that the 15 ppm hydrotreater being used to produce highway fuel could not be revamped to incorporate production of 500 or 15 ppm NRLM fuel. Thus, with one exception, we assumed that the production of 500 ppm NRLM fuel by mix refineries would require would require a grass roots hydrotreater. The later production of 15 ppm NRLM fuel was assumed to be a revamp of this 500 ppm hydrotreater, given that the 500 ppm unit was designed knowing that the nonroad and L&M caps would soon be 15 ppm. Thus, with two exceptions, there are no presumed synergies between the highway and NRLM fuel programs for these refineries.

One exception to this assumption involved the way certain refineries are expected to produce their 15 ppm highway fuel. As described above, we project that 80 percent of 15 ppm highway fuel can be produced via a revamp of the existing highway fuel hydrotreater. The remaining 20 percent of highway fuel volume will be produced with a new grass roots hydrotreater. In these latter cases, the current highway hydrotreater will be available to produce 500 ppm NRLM fuel at no capital cost.

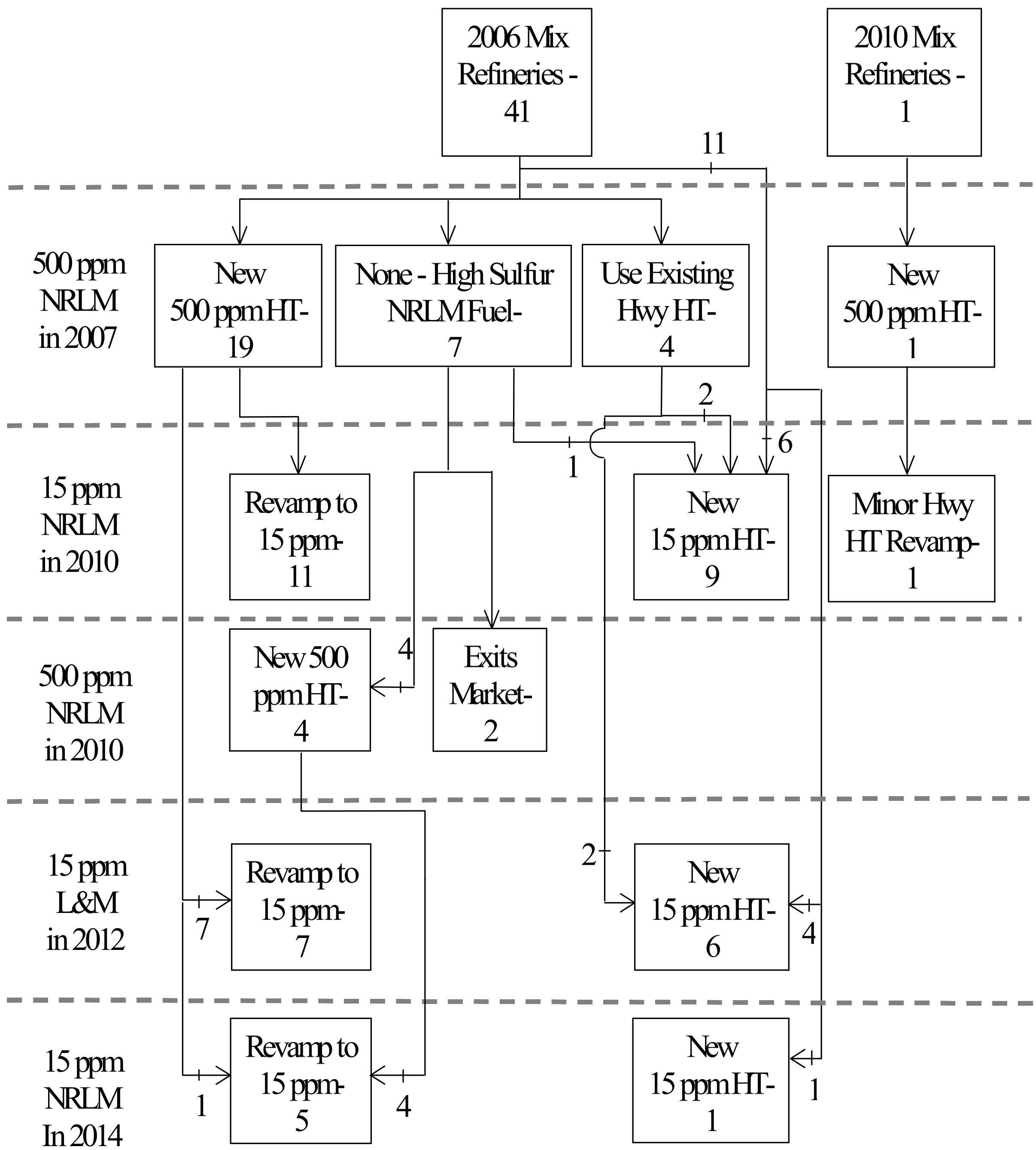
We did not attempt to identify the specific refineries which were likely to build a new grass roots hydrotreater for 15 ppm highway fuel production. This decision depends on many factors, most of which involve proprietary data. Thus, we assumed that 20 percent of the highway fuel from highway refiners and 20 percent of the highway fuel from mix refiners was being produced with a new grass roots unit. We assumed that 20 percent of the high sulfur distillate production from mix refiners could be produced with these hydrotreaters at no capital cost. Then in 2010 and 2012, new grass roots units would be required to produce 15 ppm nonroad and 15 ppm L&M fuel, as was assumed for the other mix refineries.

The other exception was a single refinery which projected that they would not begin producing 15 ppm highway diesel until 2010. In this case, there would be sufficient leadtime for these refineries to combine their plans to produce 15 ppm highway fuel with those to produce 15 ppm NRLM fuel.[CC] This provides an opportunity for economy of scale by combining both highway and NRLM fuel volumes in a single process unit, as well as affording an opportunity for the use of advanced desulfurization technology.

Figure 7.2-7 presents a flowchart of this process for mix refineries.

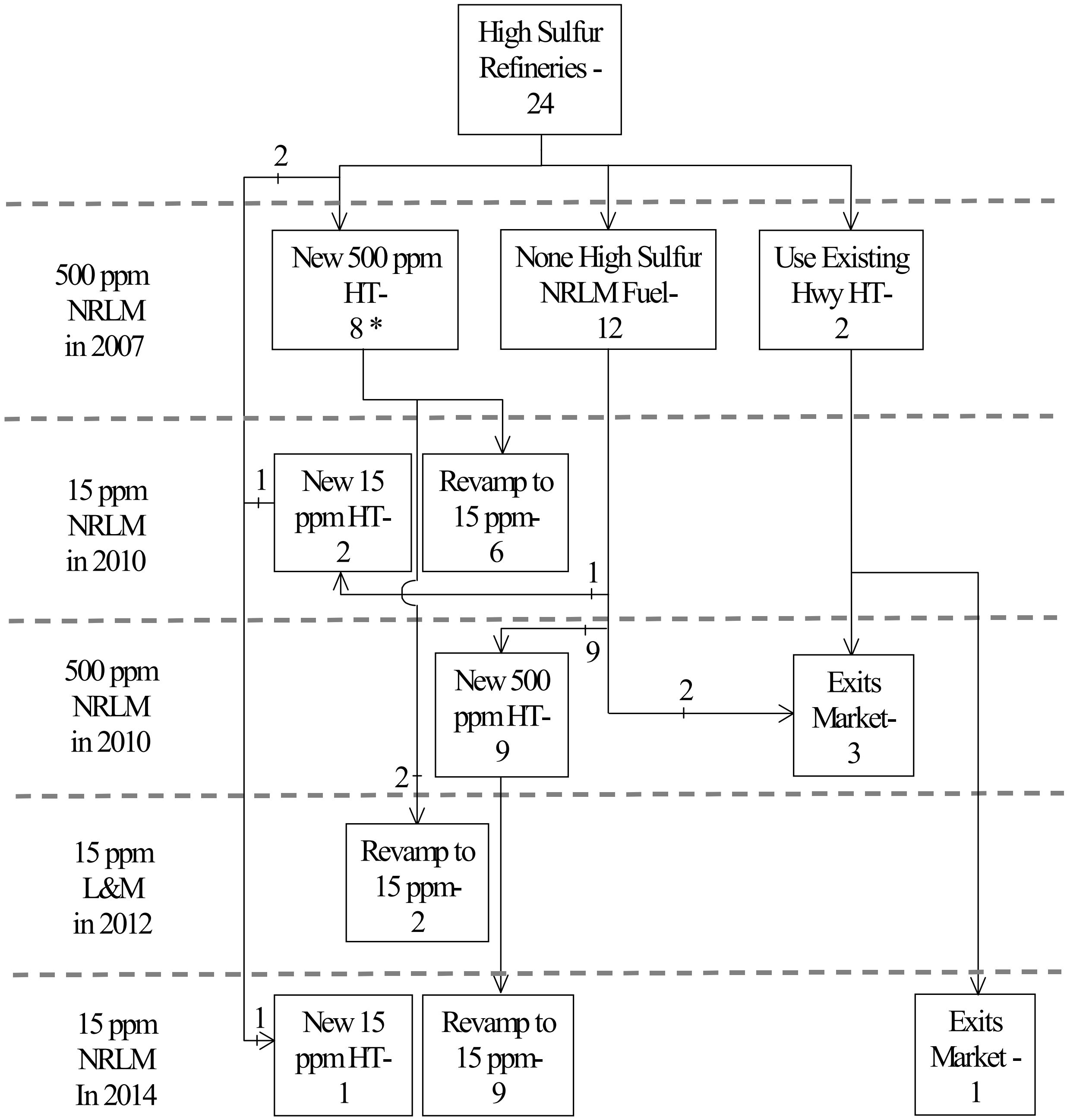
[CC] The calculation of incremental capital costs in this situation is not straightforward. We provided an example calculation below to better explain our methodology in Section 7.2.1.5.3 of the Draft RIA to this rule. The reader interested in the details of this calculation is referred to that discussion.

Figure 7.2-7
"Mix" Refineries NRLM Hydrotreater Modifications



HT = Hydrotreater
Hwy = Highway
L&M = Locomotive and Marine diesel fuel
Number in box equals number of refineries.

Figure 7.2-8
"High Sulfur" Refineries NRLM Hydrotreater Modifications



HT = Hydrotreater
Hwy = Highway
L&M = Locomotive and Marine diesel fuel
Number in box equals number of refiners.
* One refinery installs a new HT and also uses it's existing Highway HT to make 500 ppm fuel.

High Sulfur Refineries: These refineries are projected to produce little or no 15 ppm highway fuel in 2010 in response to the 2007 highway diesel rule. Therefore, we assume that any 500 ppm NRLM fuel produced would require a grass-roots hydrotreater. The production of 15 ppm NRLM fuel was assumed to be a revamp of this 500 ppm hydrotreater, given that the 500 ppm unit was designed knowing that the nonroad and L&M caps would soon be 15 ppm. Thus, there are no presumed synergies between the highway and NRLM fuel programs for these refineries.

One exception to this approach is a set of three refineries which currently produce highway diesel fuel, but project in their pre-compliance reports to cease highway fuel production in 2006. Because they produce no highway fuel after 2006, by definition these refineries fall into the high sulfur refinery category. However, they clearly have the hydrotreating capacity to produce 500 ppm fuel up to their current highway fuel production. We assumed that this hydrotreating capacity was available at no capital cost to produce 500 ppm NRLM fuel in 2007. We also assumed that a grass roots hydrotreater would be needed to produce 15 ppm fuel in either 2010 for nonroad or for 2012 for L&M, as these refiners' decisions to leave the highway market likely indicated an inability to produce 15 ppm fuel via a revamp. As it turns out, only two of these three refineries had sufficient hydrotreating capacity from the highway hydrotreater to treat all their distillate production. Thus, we assumed that the third refiner would have to construct a new grass roots hydrotreater to produce 500 ppm NRLM fuel.

Figure 7.2-8 presents a flowchart of this process for high sulfur refineries.

We presume that these refineries must build a new hydrotreater in 2007 to desulfurize their current high-sulfur distillate to 500 ppm. However, due to the significant amount of lead time available, we project that these refiners can design a revamp to desulfurize all their distillate fuel to 15 ppm in 2010 or 2012 if they choose to do so.

Summary of Results: Overall, for the final NRLM fuel program, we project that 63 refineries will invest to make 15 NRLM diesel fuel by 2014. Table 7.2.1-40 summarizes the steps which we expect refineries affected by the NRLM rule to take in meeting the highway and NRLM sulfur caps in the relevant time periods. We have separated refineries into three categories, depending on the relative proportion of highway and high sulfur distillate fuel that they produce after the 2007 highway fuel program, but prior to this NRLM fuel rule.

Table 7.2.1-40
Interaction Between Compliance with the 2007 Highway and Final NRLM Fuel Programs:
Refiners Projected to Produce Some High Sulfur Distillate Fuel in 2007 Prior to the NRLM Fuel Program

Refineries that	Year and Fuel Control	Highway Refiners	Mix 2006 Refiners[a]			Mix 2010 Refiners[a]			High Sulfur Refiners[a]			Total
		Units	New Units	Revamp Units	None	New Units	Revamp Units	None	New Units	Revamp Units	None	
Modifications to comply with the 15 ppm Highway Standard (Baseline)*	2006	3	13(6)[a]	26								
	2010	0					1					
	Total	3	39			1			22			65
New Modifications to comply with NRLM Standards.	2007 500 ppm NRLM	2	19(2)	0	4	1(1)	0	0	8	0	2	36[b]
	2010 500 ppm NRLM	0	4(2)	0	0	0	0	0	9	0	0	13
	2010 15 ppm NR	3	9(1)	11(3)	0	0	0	1	2	6	0	32
	2012 15 ppm L&M	0	6(0)	7(0)	0	0	0	1	0	2	0	15
	2014 15 ppm NRLM	0	1(0)	5(2)	0	0	0	0	1	9	0	16

[a] Numbers in parentheses are a subset for each category and represent mix refineries that currently have no highway diesel fuel hydrotreater.
[b] Two high sulfur refiners use their "idled" hwy hydrotreater to make 500 ppm NRLM fuel and exit the NRLM market when the NRLM sulfur standard is lowered to 15 ppm.

As shown in Table 7.2.1-40, we project that 36 refiners would produce 500 ppm NRLM fuel in 2007. Of these 36 refineries:

- 28 will install new hydrotreaters
- 2 "highway" refiners would perform a relatively minor revamp to their highway distillate hydrotreaters, and
- 7 refineries could produce 500 ppm NRLM diesel fuel with an "idled" highway hydrotreater..

Twenty-six of the refineries that produce 500 ppm NRLM fuel have indicated that they will produce 15 ppm highway fuel in 2006 and are categorized as follows; twenty-three 2006 mix refineries, 2 highway refineries and one 2010 mix refinery. The seven refiners who use their "idled" treaters to produce NRLM are categorized as follows; four were projected to build a new hydrotreater to produce 15 ppm highway diesel fuel and will use their old highway treater to produce 500 ppm NRLM fuel. The other three refineries currently produce 500 ppm highway fuel, but indicated in their pre-compliance report that they would no longer produce highway diesel fuel starting in 2006. (Thus, these refineries were categorized as high sulfur refineries for the purpose of this analysis). One of these three refineries was also projected to install a new hydrotreater to process additional high sulfur distillate, as the capacity of their existing hydrotreater was not sufficient to process all their high sulfur distillate volume.

For all of the refineries using their "idled" highway unit, we used their operating cost to desulfurize each refineries high sulfur distillate to 500 ppm as the cost for complying with NRLM standard. Additionally, four refineries in PADD's 1&3 were assumed to invest to fulfill supply shortfalls in PADD 2. We also assumed that excess hydrotreater capacity from the highway fuel program in PADD's 1&3 is used to supply 500 ppm NRLM volume demand. This amounted to about 20 percent of the national NRLM demand.

In 2010, we project that 32 refineries will produce 15 ppm nonroad fuel while 26 refineries will produce 500 ppm NRLM (one refinery produces 15 ppm nonroad and 500 ppm L&M fuel). Thus, a total of 57 refineries produce NRLM fuel which is 21 more than produced 500 ppm NRLM fuel in 2007, despite the volume of fuels being similar. There are two reason for the additional refinery participation in 2010. One, the increase in the number of refineries affected is the availability of idled "highway" hydrotreaters for 500 ppm fuel production in 2007. The capacity of these hydrotreaters is relatively large, so a few of these refineries can produce a large volume of 500 ppm NRLM fuel in 2007. However, these refineries' costs to produce 15 ppm is not always competitive with other refineries in their PADD. Thus, many of these refineries are not projected to produce 15 ppm nonroad fuel in 2010. Their volume of nonroad fuel is replaced by other refineries producing less volume per refinery. Two, small refineries invest to produce 500 ppm NRLM fuel due to the expiration of the small refiners provisions which allow high sulfur distillate to be sold to the 500 ppm NRLM market. Thus, the total number of refineries producing 15 nonroad fuel and 500 ppm L&M in 2010 increases.

In 2012, we project that an additional 15 refineries will invest to produce 15 ppm fuel when the L&M sulfur cap is lowered to 15 ppm. This is 15 additional refineries producing 15 ppm fuel than in 2010. Fifteen refineries continue to produce 500 ppm NRLM fuel.

In 2014, with the expiration of the small refiner provisions, and additional 16 refineries invest to produce 15 ppm NRLM fuel.

7.2.1.4 Summary of Cost Estimation Factors

This section presents a variety of costs, such as those for electricity and natural gas, as well as cost adjustment factors.

7.2.1.4.1 Capital Cost Adjustment Factors

Unit Capacity: The capital costs supplied by the vendors of desulfurization technologies apply to a particular volumetric capacity. We adjust these costs to represent units with lower or higher volumetric capacity using the "sixth tenths rule."[DD] According to this rule, commonly used in the refining industry, the capital cost of a piece of equipment varies in proportion to the ratio of the new capacity to the base capacity taken to some power, typically 0.6. This allows us to estimate how the capital cost might vary between refineries due to often large differences in the amount of distillate fuel they are desulfurizing.

Stream Day Basis: The EIA data for the production of distillate by various refineries are on a calendar basis. In other words, it is simply the annual distillate production volume of the period of interest divided by the number of days in the period. However, refining units are designed on a stream day basis. A stream day is a calendar day in which the unit is operational, or is expected to be operational. Refining units must be able to process more than the average daily throughput due to changes in day-to-day operations, to be able to handle seasonal difference in diesel fuel production and to be able to re-treat off-specification batches. The capital costs for the desulfurization technologies were provided on a stream day basis.

Actual refining units often operate 90 percent of the time, or in other words, can process 90 percent of their design capacity over the period of a year. However, when designing a new unit, it is typical to assume a lower operational percentage. We assumed that a desulfurization unit will be designed to meet its annual production target while operating only 80 percent of the time. This means that the unit capacity in terms of stream days must be 20 percent greater than the required calendar day production.

Off-site and Construction Location Costs: The capital costs provided by vendors do not include off-site costs, such as piping, tankage, wastewater treatment, etc. They also generally assume construction on the Gulf Coast, which are the lowest in the nation. Off-site costs are typically assumed to be a set percentage of the on-site costs.

[DD] The capital cost is estimated at this other throughput using an exponential equation termed the "six-tenths rule." The equation is as follows: $(Sb/Sa)^e \times Ca = Cb$, where Sa is the size of unit quoted by the vendor, Sb is the size of the unit for which the cost is desired, e is the exponent, Ca is the cost of the unit quoted by the vendor, and Cb is the desired cost for the different sized unit. The exponential value "e" used in this equation is 0.9 for splitters and 0.65 for desulfurization units (Peters and Timmerhaus, 1991).

The off-site cost factors and construction location cost factors used in this analysis were taken from Gary and Handewerk.[37] The offsite factors provided by Gary and Handewerk apply to a new desulfurization unit. Off-site costs are much lower for a revamped unit, as the existing unit is already connected to the other units of the refinery, utilities, etc. Thus, we reduced the off-site factors for revamped units by 50 percent.[38]

The off-site factors vary by refinery capacity, while the construction location factors vary between regions of the country.[39] In our analysis of the costs for the Tier 2 gasoline sulfur rule, we estimated the average of each factor for each PADD. There, all the naphtha desulfurization units were new units. Thus, the PADD-average off-site factors developed for that rule were simply divided by two to estimate PADD-average factors for revamped units here. The resulting factors are summarized in Table 7.2.1-41.

Table 7.2.1-41
Offsite and Construction Location Factors

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Offsite Factor					
- New Unit	1.26	1.26	1.20	1.30	1.30
- Revamped Unit	1.13	1.13	1.10	1.15	1.15
Construction Location Factor	1.5	1.3	1	1.4	1.2

Additional Capital Costs: There are also likely some capital costs associated with equipment not included in either the vendor's estimates, nor the general off-sites. Examples include expansions of the amine and sulfur plants to address the additional sulfur removed, a new sulfur analyzer. Additionally, there are other capital costs that occur due to unpredictable events, such as material and product price changes, cost data inaccuracies, errors in estimation and other unforseen expenses. In the NPRM, we accounted for these costs, by increasing the capital costs (after off-sites adjustment) by 18 percent. A factor of 15 percent is often used for this type of analysis.[40] However, we increased this factor to 18 percent to include the costs of starting up a new unit.[41]

We received comment that this factor was not sufficient to include the more sizeable increases in sulfur plant capacity associated with this NRLM sulfur control. In several recently developed fuel programs, such as the Tier 2 gasoline and 2007 highway diesel fuel programs, the sulfur reduction per gallon was only roughly 300 ppm. Here, the reduction is more than 3000 ppm. Therefore, the cost of expanded sulfur processing capacity was sufficient small in these previous programs to be appropriately accounted for within the 18 percent factor. In this rule, much more sulfur is being removed from the fuel in the form of hydrogen sulfide, which needs to be converted to elemental sulfur in the refinery. In Section 6.2 of the Summary and Analysis of Comments, we evaluated the cost of sulfur plant expansions and developed a new set of capital cost contingency factors which more appropriately account for these costs. These revised contingency factors are shown in Table 7.2.1-42 below.

Table 7.2.1-42
Final Capital Cost Contingency Factors (% of Hydrotreater Costs Including Off-Sites)

	Capital Contingency Factor for Debottleneck Sulfur Plant	Capital Contingency Factor for New Sulfur Plant
NRLM fuel Desulfurized from Uncontrolled Sulfur to 500 ppm Standard		
Conventional - New Unit	29	53
Process Dynamics - New Unit	34	69
NRLM fuel Desulfurized from Uncontrolled Sulfur to 15 ppm Standard		
Conventional - New Unit	22	38
Process Dynamics - New Unit	26	49
NRLM fuel Desulfurized from 500ppm to 15 ppm Standard		
Conventional - Revamped Unit	18	25
Conventional - New Unit *	17	21
Process Dynamics - Revamp Unit	18	31

* Current highway hydrotreater was used to produce 500 ppm NRLM Fuel

We applied the above contingency factors to each refinery depending on whether or not it had an existing sulfur plant. We obtained this information from the 2002 EIA Petroleum Supply Annual.

Capital Amortization: The economic assumptions used to amortize capital costs over production volume and the resultant capital amortization factors are summarized below in Table 7.2.1-43.[42] These inputs to the capital amortization equation are used in the following section on the cost of desulfurizing diesel fuel to convert the capital cost to an equivalent per-gallon cost.[EE]

Table 7.2.1-43
Economic Cost Factors Used in Calculating the Capital Amortization Factor

Amortization Scheme	Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment (ROI)	Resulting Capital Amortization Factor
Societal Cost	10 Years	15 Years	0 %	7%	0.11
Capital Payback	10 Years	15 Years	39 %	6% 10%	0.12 0.16

The capital amortization scheme labeled Societal Cost is used most often in our estimates of cost made below. It excludes the consideration of taxes. The other two cost amortization schemes include corporate taxes, to represent the cost as the regulated industry might view it. The lower rate of return, 6 percent, represents the rate of return for the refining industry over the

[EE] The capital amortization factor is applied to a one-time capital cost to create an amortized annual capital cost that occurs each year for the 15 years of the economic and project life of the unit. This implicitly assumes that refiners will reinvest in desulfurization capacity after 15 years at the same capital cost, amortized annual cost, and amortized cost per gallon.

past 10 to 15 years. The higher rate of return, 10 percent, represents the rate of return expected for an industry having the general aspects of the refining industry.

7.2.1.4.2 Fixed Operating Costs

Operating costs based on the cost of capital are called fixed operating costs. These costs are termed fixed, because they are normally incurred whether or not the unit is operating or shutdown. Fixed operating costs normally include maintenance needed to keep the unit operating, building costs for the control room and any support staff, supplies stored such as catalyst, property taxes and insurance.

We included fixed operating costs equal to 6.7 percent of the otherwise fully adjusted capital cost (i.e., including offsite costs and adjusting for location factor and including the capital cost contingency) and this factor was adjusted upwards using the operating cost contingency factor.[43] The breakdown of the base fixed operating cost percentage is as follows:

Maintenance costs: 3 percent
Buildings: 1.5 percent
Land: 0.2 percent
Supplies: 1 percent
Insurance: 1 percent.

Annual labor costs were taken from the refinery model developed by the Oak Ridge National Laboratory (ORNL).[44] This model has often been used by the Department of Energy to estimate transportation fuel quality and the impact of changes in fuel quality on refining costs. Labor costs are very small, on the order of one thousandth of a cent per gallon.

7.2.1.4.3 Utility and Fuel Costs

Utility and fuel costs, which comprise the bulk of what is usually called variable operating costs, only accrue as the unit is operating and are zero when the unit is not operating. These costs are usually based on calendar day capacity and include utility and fuel costs associated with operating a hydrotreater. Additionally, we assign diesel product losses (diesel that is cracked to gas and gasoline) that occur during hydrotreating to the variable operating costs. These losses where described in Section 7.2.1.2 above along with the other aspects of conventional and IsoTherming hydrotreating technologies.

We received comments that the utility and fuels (primarily natural gas) prices did not reflect future prices that will likely exist due to the changing supply and demand balance for ths fuel. In the NPRM, we based future natural gas prices on the five year average price between 1995 and 2001. It now appears that the high natural gas prices existing over the past few years are likely to remain, at least to some degree. Prices have shifted from the $1.5-2.25 per mmBTU range existing during the 1990's to much higher levels.

Thus, for the final rule, we decided to base natural gas prices, as well as those for other fuels and utilities on EIA's price projections contained in their 2003 AEO. These price projections are based on long term economic modeling and consider various market impacts of supply and demand dynamics on fuels and utility prices, i.e. growth in GDP, known fuels regulations, costs of refining products, increased industrial uses, etc. AEO 2003 presents these prices for every year from 2000 to 2025. For simplicity, we chose to use 2014 as a reasonable approximation of the range of prices likely to occur throughout the period of this analysis. This is also the same year for which we project refinery fuel production volumes. Table 7.2.1-44 presents these AEO prices.

Table 7.2.1-44
Fuel and Utility Prices in 2014: 2003 AEO

	2003 AEO - Future Prices	
Fuel and Utility	Price	AEO Table No.
LPG	$35.49 per bbl	12
Gasoline	$1.406 per gallon *	12
Highway Diesel	$1.390 per gallon *	12
High Sulfur Diesel	$0.865 per gallon	12
Electricity	$0.0440 per kilowatt-hour	8
Natural Gas	$4.15 per mmBTU	3

* Includes excise taxes.

These fuel and utility prices represent national averages. The highway fuels include excise taxes. We removed these taxes in our analysis.[FF] Also, we desired to reflect differences in fuel and utility costs across the various PADDs. Therefore, we developed a methodology to adjust these national average prices to reflect this variability, while still producing the same national average price when re-averaged across the U.S.

To do this, we evaluated how prices (excluding taxes) varied by PADD in 2001. For LPG, gasoline and diesel fuels, this information was available by PADD. However, for natural gas and electricity, it was available by state. Thus, for these two fuels, we averaged the prices for all the states within each PADD. In all cases, we then assumed that these PADD-specific variations would be maintained in the future on a relative basis.

For LPG, motor gasoline and diesel fuels, we obtained prices (excluding taxes) from EIA's 2001 Petroleum Marketing Annual. Table 7.2.1-45 provides a summary of the specific places within the EIA 2001 report where we obtained the 2001 pricing information. Future prices were determined assuming that each PADD's price in 2001 would change in direct proportion to the change in the AEO national average price (including taxes) from 2001 to 2014. The results are presented in Table 7.2.1-45.

[FF] Table EN-1 EIA Petroleum Marketing Annual 2002.

Table 7.2.1-45
2001 Fuel Prices: Petroleum Marketing Annual: 2001 ($/gallon)

	LPG	Gasoline	Highway Diesel Fuel	High Sulfur Diesel Fuel
PMA Table No.	38 (Industrial Users)	31 (Sales for Resale)	41 (Sales for Resale)	41 (Sales for Resale)
PADD 1	0.626	0.862	0.768	0.761
PADD 2	0.589	0.898	0.829	0.820
PADD 3	0.502	0.814	0.742	0.730
PADD 4	0.588	0.943	0.875	0.851
PADD 5	0.658	1.003	0.826	0.794
National Avg.	0.556	0.888	0.794	0.771

We also obtained state-specific electricity prices and natural gas prices data from the EIA. Electricity prices were obtained from EIA's Electricity Power Annual, 2000 and 2001.[GG] Natural gas prices were obtained EIA's Natural Gas Navigator.[HH] In order to smooth out significant price volatility between various regions, we averaged electricity prices across two years (2000-2001) and averaged natural gas prices across 5 years (1997-2001). We estimated the average price for refineries in each PADD by weighting the state-specific prices by the volume of crude oil that refiners process in each state. This approach reflects geographic breakdown of the relative electricity and natural gas usage that would occur from additional hydrotreating. We obtained refinery raw crude throughput from EIA's 2001 Petroleum Supply Annual. We assumed that these historical PADD-specific price differentials would be maintained in the future. The PADD-specific historical prices for electricity and natural gas are summarized in Table 7.2.1-46.

[GG] Table 7.4 and Figure 7.7.

[HH] Industrial prices.

Table 7.2.1-46
Historical Fuel Prices: EIA

	Electricity (c/kW-hr)	Natural Gas ($ per mmBTU)
PADD 1	6.4	4.65
PADD 2	4.4	4.64
PADD 3	4.6	3.33
PADD 4	3.7	4.16
PADD 5	6.6	4.39
National Avg.	5.1	3.96

The national average fuel and utility prices shown in Table 7.2.1-47 below were then multiplied by the ratios of the historical PADD-specific differences to the historical national average price shown in Tables 7.2.1-45 and 7.2.1-46.

Finally, we assumed that steam was generated from natural gas at an efficiency of 50 percent.[45] We assumed that natural gas feedstocks costs dominated the overall cost, so that on a BTU basis steam cost twice that of natural gas. The steam cost per pound was estimated by dividing this cost per mmBTU by the heat content of steam at 300 psi (809 BTU per pound). The resultant PADD-specific future fuel and utility prices are shown in Table 7.2.1-47.

Table 7.2.1-47
Summary of 2014 Fuel and Utility Prices for Variable Operating Cost Estimations

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5
Electricity (cents per kilowatt-hour)	5.51	3.78	3.99	3.24	5.77
LPG (dollars per barrel)	20.98	19.74	16.82	19.71	22.05
Highway Diesel (cents per gallon)	79.1	85.4	76.4	90.1	85.1
Non-highway Diesel (cents per gallon)	72.4	78.1	69.5	81.1	75.6
Gasoline (dollars per barrel)	31.9	33.7	31.2	35.6	41.5
Steam (cents per pound @ 300 psi)	0.35	0.35	0.25	0.31	0.33
Natural Gas ($/Mmbtu)	4.9	4.8	3.5	4.4	4.6

* Prices using EIA's AEO 2003.

7.2.1.4.4 Hydrogen Costs

Hydrogen costs were estimated for each PADD based on the capital and operating costs of installing or revamping a hydrogen plant fueled with natural gas. The primary basis for these costs is a technical paper published by Air Products, which is a large provider of hydrogen to refineries and petrochemical plants.[46] The particular design evaluated was a 50 million scf/day steam methane reforming hydrogen plant installed on the Gulf Coast. The capital cost includes a 20 percent factor for offsites. The process design parameters from this paper are summarized in the Table 7.2.1-48.

Table 7.2.1-48
Process Design Parameters for Hydrogen Production *

Cost Component	Dollars per thousand standard cubic feet ($/MSCF)
Natural Gas	1.18
Utilities	
Electricity	0.03
Water	0.03
Steam	-0.07
Capital/Fixed Operating Charges	0.83
Total Product Cost	2.00

* Natural Gas @ $2.75/MMBTU; Steam @ $4.00/M lbs; Electricity @ $0.045 KWH

The estimates shown in Table 7.2.1-48 were adjusted to reflect natural gas and utility costs in each PADD (shown in Table 7.2.1-46). Changes in the value of steam production and the cost of water were ignored, as these costs are very small. The capital cost and fixed operating costs were increased by 8 percent to reflect inflation from 1998 to 2001.

We also adjusted the capacity of the hydrogen plant to reflect the capacity which would be typical for each PADD. The hydrogen plant capacity for PADD 3 represents the average of the existing hydrogen plants in the PADD and several third party units producing 100 million scf/day of hydrogen. For other PADDs, the average plant size was based on the average of refinery-based hydrogen plants within that PADD, obtained from the Oil and Gas Journal.[47] We incorporated PADD-specific offsite and construction location factors from Table 7.2.1-41, again assuming a 50-50 mix of new and revamped units. Table 7.2.1-49 summarizes the average plant size and the offsite and location factors for the installation of hydrogen plant capital for each PADD.

Table 7.2.1-49
Summary of Capital Cost Factors used for Estimating Hydrogen Costs by PADD

PADD	Capacity (million scf/day)	Offsite Factor	Construction Location Factor
1	15	1.19	1.5
2	34	1.19	1.3
3	65	1.15	1.0
4	19	1.38	1.4
5 Excluding CA and AK	15	1.23	1.2
Alaska	15	1.23	2.0

The adjusted hydrogen costs in each PADD are summarized in Table 7.2.1-50.

Table 7.2.1-50
Estimated Hydrogen Costs by PADD

PADD	Cost ($/1000 scf)
1	3.56
2	3.01
3	2.09
4	3.33
5 Excluding CA and AK	3.19
AK	3.97

7.2.1.4.5 Other Operating Cost Factors

Similar to the 15 percent contingency factor for capital costs, we included a 10 percent contingency factor to account for operating costs beyond those directly related to operating the desulfurization unit.[48] This factor accounts for the operating cost of processing additional hydrogen sulfide in the amine plant, additional sulfur in the sulfur plant, and other costs that may be incurred but not explicitly accounted for in our cost analysis. We then increased this factor by 2 percent to account for reprocessing of off-specification material (actual "off-spec" allowance is 1/2-1 percent). We adjusted the operating costs to account for as much as 5 percent of all batches to be re-processed. However, this is a conservative assumption for this cost analysis. Furthermore, since this material will have been desulfurized to a level close to the 15 ppm cap, the operating costs for reprocessing it should be much lower the second time around.

We also believe refinery managers will have to place a greater emphasis on the proper operation of other units within their refineries, not just the new diesel fuel desulfurization unit, to consistently deliver diesel fuel under the new standards. For example, meeting a stringent sulfur requirement will require that the existing diesel hydrotreater and hydrocracker units operate as expected. Also, the purity and volume of hydrogen coming off the reformer and the hydrogen plant are important for effective desulfurization. Finally, the main fractionator of the FCC unit must be carefully controlled to avoid significant increases in the distillation endpoint, as this can increase the amount of sterically hindered compounds sent to the diesel hydrotreater.

Improved control of each of these units may involve enhancements to computer-control systems, as well as improved maintenance practices.[49] Refiners may be able to recoup some or all of these costs through improved throughput. However, even if they cannot do so, these costs are expected to be less than 1 percent of those estimated below for diesel fuel desulfurization.[50 51] No costs were included in the cost analysis for these potential issues.

7.2.1.5 Projected Use of Advanced Desulfurization Technologies

In Chapter 5, we projected the mix of technologies used to comply with a program being implemented in any year. This projection took into account the factors that affect the decisions by refiners in choosing a new technology. The projected mix of technologies for certain important years is summarized in Table 7.2.1-51 for the reader's benefit.

Table 7.2.1-51
Projected Use of Advanced Desulfurization Technologies for Future Years

	2007	2010	2012+
Conventional Technology	100	40	40
Process Dynamics Isotherming	0	60	60

7.2.2 Refining Costs

In this section, we present the refining costs for the final NRLM diesel fuel program. As described in Section 7.2.1, the costs to produce 500 ppm fuel were estimated using conventional technology, while those for 15 ppm fuel were projected using both conventional and advanced desulfurization technologies. All costs assume the economies of scale for the production of refineries projected to exist in 2014. Each refinery's projected costs consider their projected production of highway diesel fuel under the 2007 highway fuel program, as well as estimates of its distillate blendstock composition and location (i.e., PADD). Per gallon refining costs assume a 7 percent before tax rate of return on capital. The sensitivity of these costs to 6 percent and 10 percent after tax rates of return are also evaluated.

The refining costs for the 15 ppm sulfur cap on highway diesel fuel are presented first. While the determination of most of the refineries projected to produce highway fuel was made using the refiners' highway fuel pre-compliance reports, additional highway fuel was needed in PADDs 4 and 5. This was determined using the projected refinery-specific costs of producing 15 ppm fuel. As these costs incorporate several updates since the publication of the Final RIA for the 2007 highway diesel rule, we thought it appropriate to summarize these updated costs here.

The next section presents refining costs for the final NRLM fuel program. First, the overall costs of the program are summarized. Then, refining costs for the four main time periods of the program are presented: 1) 2007-2010, 2) 2010-2012, 3) 2012-2014, and 4) 2014 and beyond. All of these costs are based on NRLM fuel production volumes expected to exist in 2014, the mid-point of the life of desulfurization equipment built in 2007. All per gallon costs presented in this section are then applied to the volume of NRLM diesel fuel actually being desulfurized under the final fuel program. These costs would not apply to NRLM diesel fuel already meeting highway diesel fuel sulfur standards (i.e., spillover fuel).

In addition, we also present refining costs for a number of sensitivity cases:

1) Increasing the rate of return on capital to 6-10 percent after taxes,
2) No assumed use of advanced desulfurization technology,
3) A long term 500 ppm cap for NRLM fuel (i.e., no subsequent 15 ppm cap),
4) Nonroad fuel at 15 ppm and locomotive and marine fuel at 500 ppm indefinitely, and
5) The final NRLM fuel program with lower NRLM fuel demand.

Finally, we present the stream of capital costs which would be required by the NRLM fuel program, in the context of other environmental requirements facing refiners in the same timeframe, due to the Tier 2 gasoline sulfur program and the 2007 highway diesel fuel program.

7.2.2.1 15 ppm Highway Diesel Fuel Program

The refining costs associated with compliance with the 15 ppm highway diesel cap were estimated for 2006 and 2010. As the methodology used to project these costs differs somewhat from that used in the Final RIA for the 2007 highway diesel rule, the costs presented here also differ and represent an update to those costs. The projected costs for producing 15 ppm highway diesel fuel are summarized in Table 7.2.2-1.

Table 7.2.2-1
Highway Diesel Desulfurization Costs to Meet a 15 ppm Cap Standard
($2002, 7% ROI before taxes)*

	Refineries Initially Producing 15 ppm Fuel in:		All Refineries
	2006	2010	
Number of Refineries	96	4	100
15 ppm Fuel Production (million gal/yr in 2014)	53,495	2,022	55,517
Total Capital Cost ($Million)	6,060	120	6,180
Average Capital Cost per Refinery ($Million)	63.1	30.9	61.8
Average Operating Cost per Refinery ($Million/yr)	15.3	10.6	15.1
Total Cost (c/gal)	4.0	3.2	4.0

* Includes impact of highway fuel that is down graded in the distribution system.

As can be seen, we project that 96 refiners will invest to produce 15 ppm highway fuel in 2006, with a total capital cost of $6.06 billion ($63.1 million per refinery). The average cost to produce 15 ppm highway diesel fuel is 4.0 cents per gallon. These costs assume that all the 15 ppm fuel is being produced using conventional hydrotreating.

We project that 4 additional refineries will invest to produce 15 ppm highway diesel fuel in 2010, as the temporary compliance option expires. The required capital cost will be $120 million ($30.9 million per refinery). The average cost for 15 ppm fuel newly produced in 2010 is 3.2 cents per gallon, which is 0.8 cents lower than 15 ppm fuel first produced in 2006. The use of advanced technology acts to lower the cost of refiners initially entering the market in 2010. Additionally, 3 of the 4 refineries entering in 2010 desulfurize their high sulfur distillate and existing highway diesel volume in a single hydrotreater, resulting in lower costs due to economies of scale.

Overall, 100 refineries produce the 15 ppm diesel fuel under the 2007 highway diesel fuel program, with a total capital cost of $6.18 billion ($61.8 million per refinery). The average refining cost in 2010 will be 4.0 cents per gallon of fuel.

7.2.2.2 Costs for Final Two Step Nonroad Program

The final NRLM fuel program requires that NRLM fuel meet a 500 ppm sulfur cap in 2007, with a further reduction to 15 ppm in 2010 for nonroad and 2012 for L&M. Small refiners have until 2010 to meet the 500 ppm cap, and until 2014 to meet the 15 ppm cap for NRLM fuels. However, “small refiner” fuel cannot be sold in a designated region basically comprising the Northeast and Mid-Atlantic regions. Small refiners can also choose to produce NRLM fuel which meets the above standards on time and sell “credits” to other refiners, who can then sell NRLM fuel under the delayed standards. Also, 15 ppm fuel which is contaminated during distribution and still meets a 500 ppm cap can be sold to the NRLM market through 2014, and to the locomotive and marine fuel markets indefinitely.

In this section, we first present an overall summary of the costs of the entire final NRLM fuel program. Then we present in greater detail the refining costs for the four distinct time periods of the final NRLM fuel program: 1) the 500 ppm NRLM cap in 2007, 2) the 15 ppm nonroad cap and 500 ppm L&M cap in 2010 (and 500 ppm cap for small refiner nonroad fuel), 3) 15 ppm NRLM cap in 2012 (and 500 ppm ppm cap for small refiners), and 4) the 15 ppm NRLM diesel fuel program in 2014. Following these presentations, we present projected costs for the various sensitivity cases.

Overall, for the final NRLM fuel program, we project that 63 refineries will invest to make 15 NRLM diesel fuel by 2014. A summary of the projected refining costs for the various steps in the final NRLM fuel program is presented in Table 7.2.2-2.

Table 7.2.2-2
Number of Refineries and Refining Costs for the Final NRLM Program

	Year of Program	500 ppm Fuel		15 ppm Fuel	
		All Refineries	Small Refineries	All Refineries	Small Refineries
Number of Refineries Producing 500 or 15 ppm NRLM Diesel Fuel	2007-2010	36[a]	0	0	0
	2010-2012	26	13	32	2
	2012-2014	15	13	47	2
	2014-2020	0	0	63	15
Production Volume (Million gallons per year in 2014)	2007-2010	13,327	0	0	0
	2010-2012	3,792	393	8,598	335
	2012-2014	728	393	12,247	335
	2014-2020	0	0	13,030	728
Refining Costs (c/gal)	2007-2010	1.9[a]	0	0	0
	2010-2012	2.7	3.7	5.0	5.2
	2012-2014	2.9	3.7	5.6	5.2
	2014-2020	0	0	5.8	6.9

[a] In 2007-10, refinery counts do not include 500 ppm NRLM fuel from excess capacity in 15 ppm highway hydrotreaters, and a few idled highway hydrotreaters. However, refining costs do include this fuel.

As can be seen, the per gallon cost of producing 500 ppm and 15 ppm diesel fuels throughout the various phases of the NRLM fuel program will be 1.9-2.9 and 5.0-5.8 cents, respectively. We project that the cost of the 500 ppm cap for small refiners will be 3.7 cents per gallon, or 28 percent greater than that for the average refiner. We project that the cost of the 15 ppm cap for small refiners will be 6.9 cents per gallon, or 19 percent greater than that for the average refiner. Table 7.2.2-3 presents a summary of the capital and annual costs for average and small refiners.

Table 7.2.2-3
Refining Costs for the Final NRLM Program Fully Implemented in 2014
($2002, 7% ROI before taxes)

	All Refineries	Small Refineries
Number of Refineries	63	15
Total Refinery Capital Cost ($Million)	2,280	250
2007	310	0
2010	1,170	150
2012	590	0
2014	210	100
Average Refinery Capital Cost ($Million)	36.2	16.7
Average Refinery Operating Cost ($Million/yr)	8.1	2.2

As can be seen, total capital costs would be $2,280 million for the entire final 15 ppm NRLM fuel program (average of $36.2 million per refinery). Total capital costs for the 15 small refineries would be $250 million (average of $16.7 million per refinery).

7.2.2.2.1 Refining Costs in Year 2007

We project that 36 refiners would produce 500 ppm NRLM fuel in 2007. The cost of the 500 ppm NRLM cap in 2007 is summarized in Table 7.2.2-4 below.

Table 7.2.2-4
Refining Costs in 2007 for 500 ppm NRLM Diesel Fuel
($2002, 7% ROI before taxes)[a]

	All Refineries
Number of Refineries	36
Total Refinery Capital Cost ($Million)	310
Average Refinery Capital Cost ($Million)	8.6
Average Refinery Operating Cost ($Million/yr)	4.9
Amortized Capital Cost (c/gal)	0.3
Operating Cost (c/gal)	1.6
Cost Per Affected Gallon (c/gal)	1.9

We project that the total capital cost will be $310 million (an average of $10.3 million for each of the 30 refineries actually building new equipment). The total refining cost for the 500 ppm NRLM diesel fuel sulfur cap is 1.9 cents per gallon of affected fuel volume, including both operating and amortized capital costs.

7.2.2.2.2 Refining Costs in Year 2010

We project that 32 refineries will produce 15 ppm nonroad fuel in 2010. This is four fewer refineries than produced 500 ppm NRLM fuel in 2007, as some refineries continue to produce 500 ppm L&M fuel. The total refining costs to produce 15 ppm nonroad fuel in 2010 are presented in Table 7.2.2-5. Separate costs are shown for all refineries, refineries not owned by small refiners, and for those owned by small refiners.

Table 7.2.2-5
Total Refining Costs in 2010 for 15 ppm Nonroad Diesel Fuel
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refinery
Number of Refineries	32	30	2
Incremental Capital Cost ($Million)	1,090	1,030	59
Average Refinery Capital Cost ($Million)	34	32.2	30
Average Refinery Operating Cost ($Million/yr)	9.0	8.7	10.8
Capital Cost (c/gal)	1.6	1.6	1.9
Operating Cost (c/gal)	3.4	3.4	3.3
Cost Per Affected Gallon (c/gal)	5.0	5.0	5.2

The incremental capital cost in 2010 to produce 15 ppm nonroad fuel is $1,090 million. The average cost of producing 15 ppm nonroad diesel fuel is 5.0 cents per gallon. This is 3.1 cents per gallon more than the average cost to produce 500 ppm NRLM fuel in 2007. This incremental cost of 3.1 cents per gallon is lower than the 4.0 cent per gallon cost estimated above for the 15 ppm highway diesel fuel cap. This difference is due to several factors which have opposing impacts. There are three factors that tend to increase the cost of 15 ppm nonroad fuel compared to that of 15 ppm highway fuel. One, the vast majority of relatively inexpensive hydrocrackate was assumed to used in the highway diesel pool. Two, refiners projecting to produce 15 ppm highway fuel based on pre-compliance report data and cost projections tend to be those that face lower costs (greater economies of scale, low LCO fractions, etc.). Three, 80 percent of current 500 ppm highway fuel hydrotreaters assumed to be revamped to produce 15 ppm diesel fuel, while the figure is lower for nonroad fuel. While we project that all the new hydrotreaters built in 2007 to produce 500 ppm NRLM fuel can be revamped to 15 ppm fuel production, we assume that none of the existing highway hydrotreaters producing 500 ppm NRLM fuel in 2007 can be revamped to produce 15 ppm fuel. This lowers the overall revamp percentage to less than 80 percent. However, balancing these factors is our projection that a significant percentage of refiners will use the Process Dynamics and other advanced desulfurization technologies in 2010, versus 2006 when the vast majority of 15 ppm highway fuel will first be produced. This one factor essentially compensates for the other three factors in the other direction.

As implied in Table 7.2.2-5, most small refiners participating in the NRLM fuel market produced 500 ppm NRLM fuel in 2010. However, two small refiner’s costs for producing 15 ppm fuel were competitive with the other refineries in producing sufficient volumes of fuel to satisfy market demand. These small refiners were assumed to sell their credits to non-small refineries, allowing them to produce 500 ppm nonroad fuel in 2010.

A significant volume of 500 ppm nonroad fuel will also be produced in 2010 under the small refiner provisions. The remaining 500 ppm fuel production is for the L&M fuel market. The costs of producing 500 ppm diesel fuel in 2010 are presented in Table 7.2.2-6.

Table 7.2.2-6
Refining Costs in 2010 for 500 ppm NRLM Fuel
($2002, 7% ROI before taxes)

	All Refineries in 2010	Non-Small Refineries in 2010	Small Refineries in 2010
Number of Refineries	26	13	13
Total Refinery Capital Cost ($Million)	197	107	90
Average Refinery Capital Cost ($Million)	7.6	8.3	6.9
Average Refinery Operating Cost ($Million/yr)	3.7	6.7	0.8
Capital Cost (c/gal)	0.5	0.3	1.9
Operating Cost (c/gal)	2.2	2.3	2.1
Cost Per Affected Gallon (c/gal)	2.7	2.6	3.7

We project that 26 refineries will produce 500 ppm NRLM fuel in 2010 at an average cost of 2.7 cents per gallon. Thirteen of these refineries are owned by small refiners and are the only refineries that newly invest in 2010 for new hydrotreaters to produce 500 ppm fuel. Thirteen non-small refineries who produce 500 ppm NRLM fuel in 2007 would continue to produce 500 ppm NRLM fuel in 2010. Two of these non-small refiners produce 500 ppm fuel using credits generated by small refiners producing 15 ppm nonroad fuel in 2010. The small refiners per gallon costs are 37 percent more than the average of refiners producing fuel in 2010. The costs for refiners that enter the market in 2010 are lowered by the non-small refineries.

7.2.2.2.3 Refining Costs in Year 2012

In 2012, L&M fuel produced or imported must meet a 15 ppm cap. However, 500 ppm fuel produced during the distribution of cleaner fuels can be sold to the NRLM markets which reduces the volume of fuel that must be desulfurized to a 15 ppm standard. Additionally, the provisions that allow small refiners to sell 500 ppm fuel into the NRLM markets also continue. The cost of producing 15 ppm NRLM fuel in 2012 is shown in Table 7.2.2-7.

Table 7.2.2-7
Total Refinery Costs in 2012 to Produce 15 ppm NRLM Fuel
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refineries
Number of Refineries	47	45	2
Total Refinery Capital Cost ($Million)	1,980	1,920	59
Average Refinery Capital Cost ($Million)	42.1	42.7	30
Average Refinery Operating Cost ($Million/yr)	9.6	9.8	5.5
Capital Cost (c/gal)	1.8	1.8	1.9
Operating Cost (c/gal)	3.8	3.8	3.3
Cost Per Affected Gallon (c/gal)	5.6	5.6	5.2

We project that 47 refineries would produce 15 ppm NRLM fuel, or 15 more than in 2010. The total refining cost measured from today's high sulfur level would be 5.6 cents per gallon, or 0.6 cent per gallon more than in 2010. Small refineries would have average cost of 5.2 cents per gallon, or 7 percent lower than the average non-small refineries.

The 15 ppm costs for the 15 refineries first producing 15 ppm L&M in 2012 are presented in Table 7.2.2-8. All of these 15 refineries are non-small refineries and have an incremental capital investment of $590 million. The average cost of producing 15 ppm L&M diesel fuel is 7.3 cents per gallon. This is 5.4 cents per gallon more than the average cost to produce 500 ppm NRLM fuel in 2007. This incremental cost of 5.4 cents per gallon is higher than the 4.0 cent per gallon cost estimated above for the 15 ppm highway diesel fuel cap. As mentioned for the 2010 15 ppm nonroad costs, several factors tend to increase the cost to desulfurize NRLM fuels to a 15 ppm standard compared to that of 15 ppm highway fuel. The incremental desulfurization costs are higher for L&M fuel because a large portion of the lowest cost refiners were selected to invest in 2010 for 15 ppm nonroad fuel production leaving higher costs refiners producing L&M and high sulfur distillate fuels. Thus in 2012, L&M 15 ppm fuel is produced from these remaining refineries with higher desulfurization costs.

Table 7.2.2-8
Refining Costs for 15 ppm L&M Fuel for Refiners Initially Complying in 2012
($2002, 7% ROI before taxes)

	All Refineries (Non-small)
	Total
Number of Refineries	15
Incremental Refinery Capital Cost ($Million)	590
Average Refinery Capital Cost ($Million)	39.1
Average Refinery Operating Cost ($Million/yr)	11.5
Capital Cost (c/gal)	1.9
Operating Cost (c/gal)	5.1
Cost Per Affected Gallon (c/gal)	7.0

Of the 15 additional refineries producing 15 ppm L&M fuel in 2012, six will install a new grass roots hydrotreater as they did not invest to make 500 ppm L&M fuel prior to this time. The remaining 9 refineries will revamp their new nonroad hydrotreater built in 2007 or 2010. The average refinery that produces 15 ppm L&M diesel fuel for the first time in 2012 will make a capital investment of $39.1 million.

7.2.2.2.4 Refining Costs in Year 2014

In 2014, all NRLM diesel fuel produced must meet a 15 ppm cap. Additionally in 2014, the provisions allowing 15 ppm fuel that is downgraded to 500 ppm sulfur level in the distribution system to be sold to the nonroad fuel market expire, though this fuel can continue to be sold into the locomotive and marine market. Thus, the volume of 15 ppm NRLM diesel fuel produced increases over the total volume of 15 and 500 ppm NRLM fuel produced in 2010. The cost of producing 15 ppm NRLM fuel in 2014 is shown in Table 7.2.2-9.

Table 7.2.2-9
Total Refinery Costs in 2014 to Produce 15 ppm NRLM Fuel
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refineries
Number of Refineries	63	48	15
Total Refinery Capital Cost ($Million)	2,280	2,030	250
Average Refinery Capital Cost ($Million)	36.2	42.5	16.5
Average Refinery Operating Cost ($Million/yr)	8.1	10.6	2.2
Capital Cost (c/gal)	1.9	1.7	3.1
Operating Cost (c/gal)	3.9	4.0	3.8
Cost Per Affected Gallon (c/gal)	5.8	5.7	6.9

We project that 63 refineries would produce 15 ppm NRLM fuel, or 16 more than in 2010. The total refining cost measured from today's high sulfur level would be 5.8 cents per gallon, or 0.2 cent per gallon more than in 2010. Small refineries would have an average cost of 6.9 cents per gallon, or 19 percent higher than the average non-small refineries.

The 15 ppm costs for the 16 refineries first producing 15 ppm nonroad fuel in 2014 are presented in Table 7.2.2-10. The incremental capital investment for these 16 refineries in 2014 was $210 million. Of this $210 million, $100 million will be spent by small refiners.

Table 7.2.2-10
Refining Costs for 15 ppm NRLM Fuel for Refiners Initially Complying in 2014
($2002, 7% ROI before taxes)

	All Refineries	Non-small Refineries	Small Refineries
	Total	Total	Total
Number of Refineries	16	3	13
Total Refinery Capital Cost ($Million)	300	110	190
Average Refinery Capital Cost ($Million)	18.9	36.9	14.6
Average Refinery Operating Cost ($Million/yr)	4.5	16.5	1.7
Capital Cost (c/gal)	2.4	1.4	3.9
Operating Cost (c/gal)	5.2	5.8	4.0
Cost Per Affected Gallon (c/gal)	7.6	7.2	7.9

Of the 16 additional refineries producing 15 ppm NRLM fuel in 2014, 13 are owned by small refiners. Two of the 16 refineries will install a new grass roots hydrotreater as they did not invest to make 500 ppm NRLM fuel prior to this time. The remaining 14 of 16 refineries will revamp their new nonroad hydrotreater built in 2007 or 2010. The average refinery that produces 15 ppm nonroad diesel fuel for the first time in 2014 faces a capital investment of $18.9 million, while the investment for the average small refiner is smaller at $14.6 million.

7.2.2.3 Refining Costs for Sensitivity Cases

7.2.2.3.1 Total Refining Costs at Different Rates of Return on Investment

The costs presented in the previous section all assumed a 7 percent before tax rate of return on investment. We also estimated total refining costs for the final NRLM fuel program using two alternative rates of return on investment: 1) 6 percent per year after taxes, and 2) 10 percent per year after taxes. The 6 percent rate is indicative of the economic performance of the refining industry over the past 10-15 years. The 10 percent rate is indicative of economic performance of an industry like refining which would attract additional capital investment. The total per gallon cost of producing 15 ppm NRLM fuel in 2014 using all three rates of return are shown in Table 7.2.2-11.

Table 7.2.2-11
Refining Costs in 2014 for 15 ppm NRLM Fuel in 2014 (cents per gallon, $2002)

Societal Cost: 7% ROI before Taxes	5.8
Capital Payback: (6% ROI, after Taxes)	6.1
Capital Payback: (10% ROI, after Taxes)	6.9

As can be seen, the difference in the assumed rate of return on investment increases the societal cost by 0.3-1.1 cents per gallon.

7.2.2.3.2 15 ppm Nonroad Diesel Fuel with Conventional Technology

The use of advanced technology is expected to reduce the cost of producing 15 ppm diesel fuel compared to conventional hydrotreating. To determine the sensitivity of our cost estimates to the level of advanced technology projected, we developed costs for producing 15 ppm NRLM diesel fuel with only the use of conventional hydrotreating. We did not vary the specific refineries projected to produce 15 ppm NRLM fuel in 2014 from those described in the previous section. Total refining costs to produce 15 ppm NRLM diesel fuel in 2014 using conventional technology are shown in Table 7.2.2-12.

Table 7.2.2-12
Total Refining Costs in 2014 to Produce 15 ppm NRLM Diesel Fuel
with Conventional Technology ($2002, 7% ROI before taxes)

	All Refineries	Small Refineries
Number of Refineries	63	15
Total Refinery Capital Cost ($Million)	2,730	290
Average Refinery Capital Cost ($Million)	42.7	19.2
Average Refinery Operating Cost ($Million/yr)	10.6	2.6
Capital Cost (c/gal)	2.2	3.7
Operating Cost (c/gal)	4.9	4.5
Cost Per Affected Gallon Cost (c/gal)	7.1	8.2

The total cost to produce 15 ppm nonroad diesel fuel in 2014 with conventional technology would be 7.1 cents per gallon, or 22 percent higher than the 5.8 cent per gallon cost with a mix of conventional and advanced technology. Total capital costs would be $2,730 million with conventional technology, about 20 percent higher than the $2,286 million investment including use of advanced technology (see Table 7.2-40). Operating costs would be 16 percent higher with conventional technology, $10.0 million as compared to $8.6 million with use of advanced technology. The same relative comparisons apply to the impact of advanced technology on the capital costs faced by small refiners. All of these figures represent the total cost of producing 15 ppm diesel fuel from high sulfur diesel fuel.

7.2.2.3.3 Proposed Two Step NRLM Program: Nonroad Fuel to 15 ppm in 2010 and Locomotive and Marine at 500 ppm Indefinitely

This section presents the refining costs of the NRLM program which EPA proposed: nonroad fuel at 15 ppm and locomotive and marine fuel at 500 ppm. The refining impacts of this program are shown in Tables 7.2.2-13.

Table 7.2.2-13
Refining Impacts for the Proposed Two Step NRLM Fuel Program [a]
15 ppm Nonroad Fuel in 2010 and 500 ppm Locomotive and Marine Fuel Indefinitely

	Year of Program	500 ppm Fuel [b]		15 ppm Fuel	
		All Refineries	Small Refineries	All Refineries[a]	Small Refineries
Number of Refineries Producing 500 or 15 ppm NRLM Diesel Fuel	2007-2010	36	0	0	0
	2010-2014	26	13	32	2
	2014+	20	8	40	7
Refining Costs (c/gal)	2007-2010	1.9	0	0	0
	2010-2014	2.7	3.7	5.0	5.2
	2014+	2.7	3.0	5.2	7.0

[a] Includes small refiners.
[b] In 2007-10, refinery counts do not include 500 ppm NRLM fuel from excess 15 ppm highway hydrotreaters, and a few idled highway hydrotreaters. However, refining costs do include this fuel. One refiner produces 15 & 500 ppm fuel.

Under this sensitivity case, we project that 59 refineries would eventually invest to make either 15 ppm nonroad or 500 ppm locomotive and marine fuel by 2014. The total cost of producing 500 ppm NRLM fuel in 2007 is the same as that under the final NRLM program, as the two programs are identical. In 2014, the cost of 500 ppm locomotive and marine fuel would be 2.7 cents per gallon, or sightly higher than the range for 500 ppm NRLM fuel under the final NRLM program (1.9-2.4 cents per gallon).

The total cost for producing 15 ppm fuel in this program are lower than the final NRLM program costs (5.8 cents per gallon in 2014). Less volume of 15 ppm fuel is produced and the incremental per gallon costs are less than the final programs per gallon cost. This lowers the average cost.

Table 7.2.2-14 presents a side-by-side comparison of some of the key refining impacts of the proposed and final NRLM fuel programs.

Table 7.2.2-14
Refining Costs for Two Step Program with 500 ppm Locomotive and Marine fuel versus Final NRLM Program ($2002, 7% ROI before taxes)

	Two Step Program with 15 ppm Nonroad Fuel and 500 ppm Locomotive and Marine Fuel		Final NRLM program	
	All Refineries	Small Refineries	All Refineries	Small Refineries
Number of Refineries	60	15	63	15
Total Refinery Capital Cost ($Million)	1,680	180	2,280	250
2007	310	0	310	0
2010	1,240	140	1,170	150
2012	0	0	590	0
2014	130	40	210	100
Average Refinery Capital Cost ($Million)	28.5	12.1	36.2	16.7
Average Refinery Operating Cost ($Million/yr)	6.8	1.6	8.1	2.2

Overall, the 15 ppm cap on locomotive and marine fuel in our final NRLM fuel program increases total capital investment by $600 million and increases the cost of the incremental volume of L&M fuel by 5.2 cents per gallon (from 2.7 to 7.9 cents per gallon). Table 7.2.2-15 presents the incremental refining impacts of the 15 ppm cap on locomotive and marine fuel over those of the 500 ppm cap.

Table 7.2.2-15
Refinery Impacts in 2014 for a 15 ppm Versus 500 ppm Cap on Locomotive and Marine Fuel ($2002, 7% ROI before taxes)

	All Refineries
Number of Affected Refiners	23
Total Incremental Capital, $MM	600
Incremental Fuel Cost 500ppm to 15 ppm, (c/gal)	5.2
Total Fuel Cost , (c/gal)	7.9

The 5.2 cent per gallon cost to reduce L&M fuel sulfur from 500 to 15 ppm is higher than the 3.5 cent per gallon cost for nonroad fuel, because we assumed that the refiners facing the lowest desulfurization costs would produce 15 ppm nonroad fuel, if L&M fuel sulfur remained at 500 ppm. Thus, 15 ppm L&M fuel is produced from the remaining refineries that are projected to face higher desulfurization costs.

7.2.2.3.4 Refining Costs for a 500 ppm NRLM Only Program

This section presents refining costs for a long-term 500 ppm cap on NRLM fuel (i.e., no subsequent 15 ppm cap). We evaluated costs in 2010, after any small refiner provisions would have expired. These costs are summarized in Table 7.2.2-16.

Table 7.2.2-16
Refining Costs for a Stand-alone 500 ppm NRLM Diesel Fuel Standard
($2002, 7% ROI before taxes)[a]

	All Refineries	Nonsmall Refineries	Small Refineries
Number of Refineries	57	41	16
Total Refinery Capital Cost ($Million)	480	360	120
Average Refinery Capital Cost ($Million)	8.4	8.8	7.7
Average Refinery Operating Cost ($Million/yr)	3.6	4.7	1.0
Capital Cost (c/gal)	0.4	0.3	1.5
Operating Cost (c/gal)	1.6	1.6	1.7
Cost Per Affected Gallon (c/gal)	2.0	1.9	3.2

[a] Equivalent to the costs of the 500 ppm NRLM cap in 2010 without the 15 ppm nonroad cap.

The overall refining cost of a 500 ppm NRLM fuel cap would be 2.0 cents per gallon. We project that 57 refineries would produce this fuel with a total capital investment of $480 million. On average, the refining cost for small refiners would be about 60 percent higher than that of non-small refiners at 3.2 cents per gallon.

7.2.2.3.5 EIA-Based Demand for NRLM Fuel

In Chapter 2 of the Summary and Analysis of Comments, we discuss the uncertainty in current and future demand for NRLM fuel, particularly that used in land-based nonroad equipment. While we base our primary cost estimates on fuel demands as predicted by EPA's NONROAD emission model, we decided to evaluate the sensitivity of both costs and benefits to an alternative level of fuel demand. Here, we present the refining costs assuming that the EIA-based fuel demands are more accurate than those from NONROAD.

The total refining costs to produce 500 and 15 ppm NRLM diesel fuel from 2007-2014 for the two sets of fuel demands are summarized in Table 7.2.2-17.

Table 7.2.2-17
Total Refining Costs of NRLM Fuel from 2007-2014 With Varying Fuel Demands
(Cents per gallon, $2002, 7% ROI before taxes)

	EIA-Based Fuel Demand	EPA NONROAD Fuel Demand
500 ppm NRLM fuel: 2007-2010	1.9	1.9
500 ppm NRLM fuel: 2010-2012	2.8	2.7
500 ppm NRLM fuel: 2012-2014	3.0	2.9
15 ppm Nonroad fuel: 2010-2012	5.0	5.0
15 ppm NRLM fuel: 2012-2014	5.6	5.6
15 ppm NRLM fuel: 2014+	5.7	5.8

As can be seen, reducing NRLM fuel demand has little impact on per gallon refining costs. The only differences shown are a slight increase in 500 ppm costs from 2010-2014 and a slight decrease in 15 ppm fuel costs after 2014. The former effect occurs because the incremental 500 ppm NRLM fuel volume is coming from relatively low cost Gulf Coast refineries. While the same effect exists in 2014 with respect to 15 ppm fuel costs, the effect of the reduced demand in reducing costs in other refining areas is larger. Table 7.2.2-18 provides a more detailed breakdown of the final refining impacts of the 15 ppm NRLM cap in 2014 for the two sets of fuel demands.

Table 7.2.2-18
Refining Impacts of 15 ppm NRLM Fuel in 2014 With Varying Fuel Demands
($2002, 7% ROI before taxes)

	EIA-Based Fuel Demand	*EPA NONROAD Fuel Demand*
# of Refiners	55	63
Total Refinery Capital Cost ($Million)	1,870	2,280
Average Capital Cost ($Million)	33.9	36.2
Operating Cost ($Million/yr)	7.5	8.1
Capital Cost (c/gal)	1.9	1.9
Operating Cost (c/gal)	3.8	3.9
Cost Per Gallon (c/gal)	5.7	5.8

As the EIA-based methodology reduces NRLM fuel demand, only 55 refineries would invest to produce NRLM fuel in 2014 versus 63 using the EPA NONROAD Model estimates. The total 15 ppm NRLM fuel cost would be 5.7 cents per gallon, or 0.1 cents per gallon less than that to satisfy NONROAD fuel demand. Total capital costs would be $1,870 million, or about 18 percent less than the $2,280 million investment needed to produce the additional fuel volume.

7.2.2.4 Capital Investments by the Refining Industry

Refiners must raise capital to invest in new desulfurization equipment to produce the 500 ppm and 15 ppm diesel fuel which would be required under the final NRLM fuel program. The previous sections estimated the total capital cost associated with the final and various sensitivity cases. Refiners expend this capital over a several year period prior to the time which the new equipment must be used. This section estimates how much capital would have to be expended in specific years under the final and alternative programs. These yearly expenditures are then added to those required by other fuel quality programs being implemented in the same timeframe and compared to historic capital expenditures made by the refining industry.

Two fuel quality regulations are being implemented in the same timeframe as this NRLM fuel program: The Tier 2 gasoline sulfur program and the 2007 highway diesel fuel sulfur program. In the Tier 2 gasoline sulfur control rule, we estimated the expenditure of capital for gasoline desulfurization by year according to the phase in schedule promulgated in the rule.[II] The 2007 highway diesel rule modified that phase in schedule by provided certain refiners more time to meet the Tier 2 gasoline sulfur standards. In the 2007 highway diesel rule, we projected the stream of capital investments required by the U.S. refining industry for both the modified Tier 2 standards and the 15 ppm highway diesel fuel sulfur program. We updated the allocation and amount of capital expenditures for the highway diesel rule to reflect when each refiner would invest. The new total capital costs for the 2007 highway diesel fuel program are discussed in section 7.2.2.1 above. In projecting the stream of capital expended for a particular project, we assume that the capital investment would be spread evenly over a 24 month period prior to the date on which the unit must be on-stream. The stream of projected capital investment related to the Tier 2 gasoline sulfur program and the 2007 highway diesel fuel program rule are shown in Table 7.2.2-19.

[II] Regulatory Impact Analysis - Control of Air Pollution from New Motor Vehicles: The Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, U.S. EPA, December 1999, EPA 420-R-99-023. Adjusted to 2002 dollars using Chemical Engineering Plant Cost Index.

Table 7.2.2-19
Capital Expenditures for Gasoline and Highway Diesel Fuel Desulfurization
($Billion, $2002)[a]

Calendar Year	Tier 2 Gasoline Sulfur Program	2007 Highway Diesel Program	Total
2002	1.76		1.76
2003	1.15		1.15
2004	0.88	1.82	2.70
2005	0.61	3.03	3.64
2006	0.16	1.21	1.37
2007	0.06		0.06
2008	0.06	0.43	0.49
2009	0.02	0.71	0.73
2010		0.28	0.28

[a]2002 dollars obtained by use of Chemical Engineering Plant Annual Cost Index to adjust capital costs for Tier 2 gasoline program (1997 dollars) and highway diesel capital program (1999 dollars).

The two diesel fuel programs have implementation dates of June 1 of various years for fuel leaving the refinery. For this start up date, we assumed that 30 percent of the capital cost was expended in the calendar year two years prior to start up, 50 percent was expended in the year prior to start up and the remaining 20 percent was expended in the year of start up. We repeated this analysis for the final NRLM program. The results are summarized in Table 7.2.2-20 below.

Table 7.2.2-20
Capital Expenditures for the Final NRLM Fuel Program with
Tier 2 Gasoline Sulfur and 2007 Highway Diesel Fuel Programs
($Billion, $2002)

Calendar Year	Final NRLM Fuel Program		
	Tier 2 and Highway Diesel	NRLM Program	Total[a]
2002	1.76		1.76
2003	1.15		1.15
2004	2.70		2.70
2005	3.64	0.09	3.75
2006	1.37	0.16	1.53
2007	0.06	0.06	0.12
2008	0.49	0.35	0.84
2009	0.73	0.59	1.32
2010	0.28	0.41	0.69
2011		0.29	0.29
2012		0.18	0.18
2013		0.11	0.11
2014		0.04	0.04

[a]2002 dollars obtained by use of Chemical Engineering Plant Annual Cost Index to adjust capital costs for Tier 2 gasoline program (1997 dollars) and highway diesel capital program (1999 dollars).

As can be seen, capital investments peak in 2005 for the Tier 2 and Highway diesel programs. The final NRLM program increases this peak by just $90 million, or about 2 percent. Thereafter, capital requirements drop dramatically but peak a second time in year 2009 due to the 15 ppm highway and nonroad standard. The second peak is less than 36 percent of the capital outlays that occur in year 2005. Considering all programs, when capital investment requirements are the highest, they are caused by the Tier 2 gasoline sulfur and 2007 highway diesel fuel programs. Compared to Tier 2 and the hwy diesel program, the capital investment requirements for the final NRLM fuel program are much smaller and are more spread out over time.

Estimates of previous capital investments by the oil refining industry for the purpose of environmental control are available from two sources: the Energy Information Administration (EIA) and the American Petroleum Institute (API). According to EIA, capital investment by the 24 largest oil refiners for environmental purposes peaked at $2 billion per year during the early

1990's.[JJ] Total capital investment by refiners for other purposes was in the $2-3 billion per year range during this time frame. API estimates somewhat higher capital investments for environmental purposes, with peaks of about $3 billion in 1992-1993.[KK] Based on these two sources, during the early 90's, the US refining industry invested over 20 billion dollars in capital for environmental controls for their refining and marketing operations, representing about one half of the total capital expenditures made by refiners for operations.

The capital required for the Tier 2 gasoline, 2007 highway diesel fuel and the final NRLM fuel program is about 73 percent of the historic peak level of investment for meeting environmental programs experienced during 1992-1994.[52] Additionally, most of the capital outlays for all of the about mentioned fuels programs are spread out over an eight year time period. Given that the capital required by the final NRLM fuel program contributes less than 2 percent to the required investment in the peak year of 2005, we do not expect that the industry would have difficulty raising this amount of capital, although we recognize that it does require the need to continue to raise and devote capital over a longer period of time.

7.2.2.5 Other Cost Estimates for Desulfurizing Highway Diesel Fuel

Two other studies have estimated a cost of producing 15 ppm NRLM fuel, one by Mathpro and another by Baker and O'Brien (BOB). These two studies are discussed below.

Mathpro: For the Engine Manufacturers Association and with input by the American Petroleum Institute, Mathpro used a notional refinery model to estimate the national average costs of desulfurizing nonroad diesel fuel after implementation of the 15 ppm standard for highway diesel fuel. The cost estimate from this study is presented here and compared with our costs.

In a study conducted for the EMA, MathPro, Inc. first estimated the cost of desulfurizing diesel fuel to meet a 15 ppm highway diesel fuel sulfur standard followed by two-step nonroad standards of 500 ppm and 15 ppm.[53, 54] MathPro assumed that desulfurization will occur entirely with conventional hydrotreating, and refining operations and costs were modeled using their ARMS modeling system with technical and cost data provided by Criterion Catalyst Company LP, Akzo-Nobel Chemicals Inc., and Haldor Topsoe, Inc. The Mathpro refinery model estimated costs based on what Mathpro terms a "notional" refinery. The notional refinery is configured to be typical of the refineries producing highway diesel fuel for PADDs 1, 2, and 3, and also represent the desulfurization cost for those three PADDs based on the inputs used in the refinery model. The Mathpro notional refinery model maintained production of highway diesel fuel at their base levels.

[JJ] "The Impact of Environmental Compliance Costs on U.S. Refining profitability," EIA, May 16, 2003.

[KK] U. S. Petroleum Refining, Assuring the Adequacy and Affordability of Cleaner Fuels, A Report by the National Petroleum Council, June 2000.

Mathpro made several estimates in their study to size their diesel desulfurization units for estimating the capital cost, and these estimates were similar to those included in our methodology. The calendar day volume was adjusted to stream day volume using a 10 percent factor to account for variances in day-to-day operations, and another 10 percent to account for variance in seasonal demand. In addition, Mathpro applied a factor that falls somewhere in the range of 1 to 8 percent for sizing the desulfurization unit larger for reprocessing off-spec material to meet different sulfur targets. Since meeting a 500 ppm standard is not very stringent, Mathpro likely assumed that a desulfurization unit will be sized larger by 1 to 4 percent. For meeting the 15 ppm standard, which is relatively stringent compared with the 500 ppm sulfur level studied, Mathpro likely assumed the desulfurization unit would be sized larger by 5 to 8 percent. On-site investment was adjusted to include offsite investment using a factor of 1.4. In the final report, capital costs were amortized at a 15 percent after-tax rate of return.

The Mathpro cost study analyzed the costs to comply with the highway program based on 5 different investment scenarios. Before deriving the best nonroad desulfurization cost estimate using the Mathpro cost study, we must describe the various investment scenarios. The titles of the scenarios are listed here:

1. No Retrofitting - Inflexible
2. No Retrofitting - Flexible
3. Retrofitting - De-rate/Parallel
4. Retrofitting - Series
5. Economies of Scale

Scenarios 1 and 2 do not allow retrofitting, which means the existing highway diesel hydrotreater must be removed from service and a new grassroots unit desulfurizing untreated distillate down to under 15 ppm takes its place. The difference between scenarios 1 and 2 is that scenario 1 does not allow some flexibilities that may be available to the refining industry. One flexibility is that the volume of hydrocracker units is not limited to the used capacity as listed in the 1997 API/NPRA survey, but instead the throughput can be as much as 8 percent higher, which is half the available capacity available in the API/NPRA survery. Another flexibility is that jet fuel exceeds specifications and instead of limiting the qualities to current levels, they are instead allowed to become heavier by 0.5 API or by 3 points on the E375 distillation curve and stay within the jet fuel specifications. Allowing jet fuel to get heavier allows the refinery model to bring some of these lighter jet fuel blendstocks into the highway diesel fuel pool, which lowers the desulfurization cost. The flexibilities are allowed in the rest of the scenarios as well.

Scenarios 3 and 4 allow taking advantage of the existing highway desulfurization unit by keeping it in place and installing additional capital including additional reactor volume, which allows the combined used and new capital to achieve the 15 ppm standard.
The difference between scenarios 3 and 4 is that Scenario 3 derates the existing hydrotreater, which reduces the volume treated by that unit so it can achieve 15 by itself; another unit being fed by a low throughput is then added in parallel, which allows it to meet the 15 ppm standard. Scenario 4 installs the new capital in series with the existing hydrotreater with both units handling the entire feed rate.

Scenario 5 allows the debottlenecking of existing capacity to treat a larger volume while producing the same specifications. Scenario 5 also allows a single unit to be installed to handle the desulfurization of multiple refineries in refining centers, which provides an important economy of scale for the desulfurization investment costs to that group of refineries.

While these various investment scenarios were devised to show how different investment scenarios affect the cost for the HD2007 rule, they have implications for the nonroad rule as well. For meeting the standard for nonroad diesel fuel of 500 ppm, the used highway units freed up in Scenarios 1 and 2 can thus be converted over to nonroad service, which dramatically reduces the capital cost of compliance; this supplements the existing nonroad capacity. However, for Scenario 2, the installed grassroots capacity installed for the HD2007 rule decreased after the capital was already installed and a larger volume of existing hydrotreating capacity removed from highway desulfurization service was put into place to supplement the nonroad hydrotreating capacity already in place. For Scenario 3, the needed nonroad capacity is formed by adding grassroots capacity. For Scenario 4, the necessary nonroad hydrotreating capacity is formed by increasing the existing unit capacity used, relying on some expansion of existing units and adding some processing unit capacity in series with existing capacity. The nonroad hydrotreating capacity for meeting the 500 ppm standard is realized for Scenario 5 similar to Scenario 4, except no expansion of existing units occurs, but instead more capacity from existing highway units is relied upon.

For meeting the 15 ppm cap sulfur standard for nonroad diesel fuel, the refinery model invested in nonroad capital either along the same lines as the 500 ppm case, or else invested much differently. For Scenario 1 and 2, the refinery model installed grassroots units only, even replacing some existing hydrotreating capacity that was likely being used for some mild desulfurization of nonroad diesel fuel. For Scenario 2, the volume of grassroots desulfurization capacity was slightly lower than Scenario 1, probably due to the increased flexibility granted by the refinery model. For Scenario 3, the refinery model added some new grassroots unit capacity compared with the 500 ppm case, probably derating the capacity of the remaining 500 ppm and new 500 ppm capacity. For Scenario 4, the refinery model added more series unit capacity and more expansion capacity. Finally for Scenario 5, the refinery model increased the series processing unit capacity and added some expansion capacity.

The new or existing hydrotreating capacity used for meeting the 500 ppm and 15 ppm nonroad standards incremental to meeting the highway 15 ppm sulfur standard is shown in Table 7.2.2-21.

Table 7.2.2-21
Mathpro Capital Investments (bbl/day) for Desulfurizing Highway and Nonroad Diesel Fuel

		No Retr Inflex	No Retr Flex	Retr De-rate	Retr Series	Econ of Scale
Reference Case	Existing Cap	34.9	34.9	34.9	34.9	34.9
Highway 15 ppm Cap Std	Existing Unit	8.2	8.2		31.1	31.1
	Expansion					
	De-rated			17.8		
	Series Unit			15.4	29.4	29.4
	Grassroot Unit	30.2	29.3			
Nonroad Meeting a 500 ppm Standard	Existing Unit	16.5	19.4		35.0	38.0
	Expansion				2.9	
	De-rated			17.8		
	Series Unit				34.1	34.0
	Grassroot Unit	30.1	27.6	23.7		
Nonroad Meeting a 15 ppm Standard	Existing Unit				35.0	38.0
	Expansion				4.9	1.9
	De-rated			17.8		
	Series Unit				39.1	39.1
	Grassroot Unit	50.4	49.3	26.5		

We next determined which Mathpro case best approximated the investment scenarios we are using in our 500 ppm cost analysis, but we will summarize first summarize how our cost model estimates investments will occur. As described earlier in this section, some refineries will comply with the highway HD2007 rule in 2006 by putting in a new hydrotreater and thus idling an existing hydrotreater (i.e., 20 percent of the mixed highway and nonroad refineries that have a distillate hydrotreater and comply with the highway requirements in 2006). Other refiners have said that they will exit the highway market altogether, thus freeing up their existing 500 ppm treater. We believe that the refineries exiting the highway market would use these treaters to desulfurize NRLM diesel fuel. Adding up the volumes from these two sources of existing hydrotreating capacity, we estimate that 30 percent of NRLM will be desulfurized with existing hydrotreaters. Furthermore, we estimated that 39 percent of NRLM fuel is already hydrotreated and blended into high sulfur distillate. We project that this hydrotreating will continue with the use of existing hydrotreaters. Thus, the fraction of NRLM diesel fuel meeting the 500 ppm sulfur standard in 2007 with the use of existing capital is expected to be 69 percent. The balance of the NRLM volume, which comprises 31 percent, is expected to be desulfurized with a new hydrotreater installed for startup in 2007.

We examined the Mathpro investment cases to match the investment scenarios in our cost analysis. There were no cases that matched our scenario exactly, but we found two Mathpro cases that, together, roughly matched our investment scenario. The first is the No Retrofit Inflexible case, which met the nonroad requirements exclusively through using existing capacity (with half of it already in place before the standard applied, which matches our investment scenario). The second case is the Retrofitting Derating case, which met the nonroad requirements through new capital investment. Our analysis for complying with the 500 ppm sulfur standard was based on 69 percent of the nonroad volume being produced by refineries using existing hydrotreaters and 31 percent with new units, so the Mathpro costs were weighted 69 percent No Retrofit Inflexible costs and 31 percent Retrofit DeRate costs.

We then examined the Mathpro 15 ppm cases to determine which would best match our 15 ppm scenario. Since we already described the Mathpro cases for estimating the incremental cost for going from meeting the 500 ppm standard to meeting the 15 ppm sulfur standard, we needed identify the case which best matches our 500 ppm to 15 scenario. As discussed earlier in this section, our 15 ppm scenario has new nonroad diesel fuel hydrotreating units being installed in 2010. Since we estimated that 31 percent of the volume of NRLM in 2007 is complied with using new units, we project that 31 percent of the NRLM diesel fuel would meet the 15 ppm sulfur by revamping their new 2007 treaters. The balance of the NRLM volume are projected to comply with the 15 ppm standard with grassroots units which are installed to desulfurize uncontrolled distillate fuel down to 15 ppm, with an operating cost credit for the uncontrolled to 500 ppm step. Of the Mathpro cases summarized above, the first two cases, which don't allow revamps and either allow or don't allow operational flexibility, install grassroots units for obtaining the 15 ppm standard. We decided to use Mathpro's case one, since the second Mathpro case apparently allowed backsliding in the highway grassroots units needed for complying with the HD2007 rule when the 500 ppm standard was being met, which we don't think is possible because the highway investments will be too far along before the nonroad program is finalized.

Case one, however, needed to be adjusted to better model our projections on how refiners would invest. Mathpro's case one was associated with the replacement of the existing hydrotreating capacity, all of which was likely used by the refinery model for desulfurizing nonroad down to 500 ppm. However, we believe 31 percent of the existing nonroad desulfurization capacity can be revamped instead of having to be replaced. Thus, we adjusted the Mathpro capital costs to remove 31 percent of the grassroots hydrotreating capacity which we believe would be revamped instead. We accomplished this by estimating what percent of the capital costs is necessary for complying with 15 ppm standard and which portion was necessary for replacing the expected portion of existing nonroad desulfurization capital. The nonroad diesel fuel volume needed to be treated in Mathpro's notional refinery model is 9 thousand barrels per day. According to Mathpro, the capital needed to be installed to treat the nonroad pool down to 15 ppm is increased by 10 percent to handle peak throughput rates, and then by another 10 percent to handle peak seasonal rates and then by another 8 percent to handle reprocessing of off-spec batches. Thus, the 9,000 barrels per day nonroad volume is increased to about 11,800 barrels per day, which represents Mathpro's estimated capital capacity. We subtracted 11,800 bpd from the total volume of grassroots capacity added, which was 20,300 bpd, to yield a total of 8,500 barrels per day of replaced capital capacity; we assumed this will be untreated to 500 ppm nonroad hydrotreated capacity. Since we projected that 69 percent of this existing capacity to be replaced, with the 31 percent being new units in 2007 and not replaced, we maintained 69 percent of 8,500 bpd, or an additional 5,865 barrels of the new nonroad hydrotreating capacity. We therefore maintained 17,665 bpd of the original 20,300 bpd of additional capacity added in Mathpro case one. To estimate a revised cost for Mathpro's case one we multiplied the capital charge by a ratio of 17,665/20,300. No adjustment was necessary for the variable operating cost.

In addition to the differences and adjustments as described above, there are several other differences between our cost analysis and the cost analysis made by Mathpro that were adjusted or deserve mentioning. First, the MathPro costs as reported in their final report are based on a 15 percent return on investment (ROI) after taxes. As stated above, our costs are calculated based on a 7 percent ROI before taxes, so to compare our cost analysis with the cost analysis made by Mathpro, we adjusted the Mathpro costs to reflect the rate of return on capital investment that we use. Second, the MathPro estimate includes a cost add-on (called an ancillary cost) for reblending and reprocessing offspec diesel fuel or for storing nontreated diesel fuel. While this is conceptually an appropriate adjustment to estimate the cost to the refining industry, it appears that some of the reblending costs in the MathPro study appear to be transfer payments,[LL] not costs. We did not include these costs in our cost comparison. Third, MathPro assumed that all new hydrogen demand is met with new hydrogen plants installed in the refinery, which does not consider the advantage of hydrogen purchased from a third party that can be produced cheaper in many cases. As a result, their hydrogen cost may be exaggerated, which would tend to increase costs. In fact, Mathpro's hydrogen is priced at $3.60 per million standard cubic feet ($/MSCF). However the hydrogen costs in our analysis is about $2.70 per MSCF. Finally, we note that the MathPro study took into consideration the need for lubricity additives, but did not address costs that might be incurred in the distribution system. When we compared out costs with Mathpro's, we did not include any costs that would be incurred in the distribution system not even lubricity additive costs. For comparing the aggregate capital costs, the Mathpro aggregate capital costs for the chosen cases were adjusted using the undesulfurized nonroad, locomotive, and marine diesel fuel volumes for 2007 and for undesulfurized nonroad diesel fuel for 2010. The undesulfurized volumes we used for making the adjustments are presented in Section 7.1. A comparison of Mathpro's costs and our costs to desulfurize highway diesel fuel to meet a 500 ppm sulfur standard and then a 15 ppm sulfur standard is shown below in Table 7.2.2-22.

[LL] A transfer payment is when money changes hands, but no real resources (labor, natural resources, manufacturing etc.) are consumed.

Table 7.2.2-22
Comparison of Mathpro's and EPA's Refining Costs for Meeting a
500 ppm and a 15 ppm Nonroad Diesel Fuel Sulfur Standard
(7% ROI before taxes, no lubricity additive costs nor distribution costs included)

Fuel Standard	Type of Cost	Mathpro's Costs	EPA's Costs	
		No Advanced Tech	Advanced Tech in 2010	No Advanced Tech
500 ppm Cap Std.	Per-gallon Cost (c/gal)	2.1	2.2	2.2
	Total Capital Cost (billion$)	580	310	310
15 ppm Cap Std. Incremental to 500 ppm Std. *	Per-gallon Cost (c/gal)	3.9	3.6	4.9
	Total Capital Cost (billion$)	2300	1970	2420
Uncontrolled to 15 ppm	Per-gallon Cost (c/gal)	6.0	5.8	7.1
	Total Capital Cost (billion$)	2870	2280	2730

* Fully phased-in costs in 2014

Baker and O'Brien Study: The Baker and O'Brien (BOB) study was conducted for API to estimate the costs and supply impacts of two possible NRLM fuel control programs. BOB first estimated how refiners would respond to future diesel fuel requirements absent any NRLM fuel controls. These requirements included EPA's 2007 highway fuel program and the California and Texas fuel programs.[MM] This was referred to as the Base Case in the report. The two NRLM fuel programs evaluated were:

1) Study Case- One step NRLM fuel program:
   15 ppm cap for all NRLM fuel in 2008

2) Sensitivity Case- Two step NRLM fuel program:
   500 ppm cap for all NRLM fuel by 2008
   15 ppm cap for nonroad fuel in 2010

BOB initiated their study prior to the NPRM, so they did not know exactly what NRLM fuel program would be proposed. Their two cases were designed to bracket what they believed were likely possible proposals. As it turns out, the final NRLM fuel program reflects portions of both cases. The final NRLM fuel program is a two step program, like the sensitivity case. The final 15 pm cap applies to all NRLM fuel like the study case, though in the final NRLM fuel program, significant volumes of NRLM fuel can be 500 ppm fuel resulting from contamination in the distribution system.

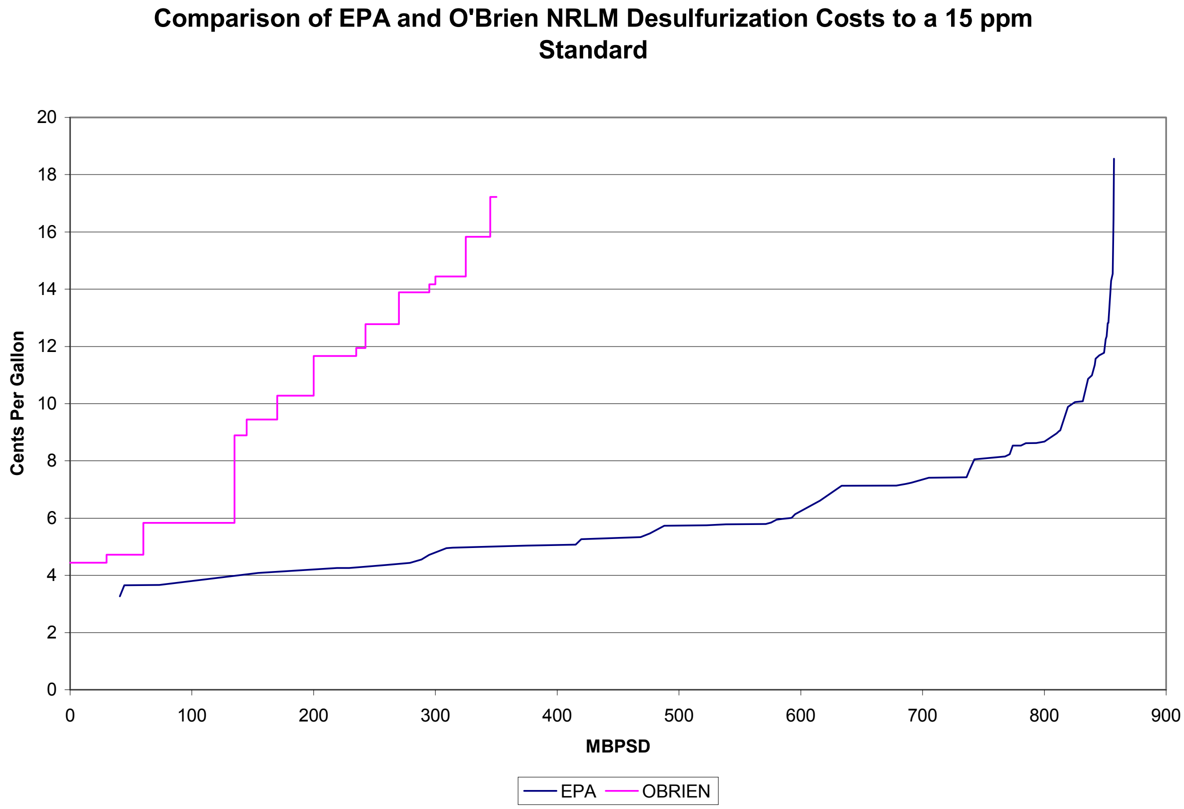
[MM] BOB assumed that refiners producing diesel fuel for Texas would have to produce the same fuel as currently being produced in California. In addition, they assumed that 100 percent of highway fuel sold in both states would have to meet a 15 ppm cap starting in mid-2006.

The fuel supply impacts of the BOB study are addressed in Section 4.6.3.1 of the Summary and Analysis of Comments document. The focus here is on their projected cost to produce low sulfur NRLM fuel. BOB did not estimate the cost of producing 500 ppm NLRM fuel under the Sensitivity Case. They only stated that roughly 300,000 bbl per day of 500 ppm diesel fuel could be produced essentially for free from idled highway hydrotreaters. This is very similar to our findings in Section 7.2.1 above. The primary difference is that we only consider the capital cost to be free, since these hydrotreaters would not be operated (i.e., zero operating cost) absent this NRLM fuel program.

BOB developed cost estimates for 15 ppm NRLM fuel, but not for 15 ppm fuel produced under the highway program. BOB did not use projected costs per gallon of producing 15 ppm fuel to predict which refineries would likely produce 15 ppm fuel under either the highway or NRLM programs. Instead, as outlined in their report, BOB made first assumed that refiners would defer USLD capital investment whenever they had a reasonable alternative, such as selling heating oil or exporting high sulfur diesel fuel. BOB also assumed that some refiners would not be able to raise or justify the capital expenditures for ULSD and would discontinue operations. In addition, BOB predicted that a sizeable number of domestic refineries would close as a result of the highway and NRLM fuel programs. As a result of these assumptions, BOB projected that domestic refiners would only produce 200,000-300,000 bbl per day of 15 ppm NRLM fuel out their estimated demand of 700,000 bbl per day.

BOB presented their cost estimates for 15 ppm NRLM for both the study and sensitivity cases. As the study case most closely approximates the fully implemented final NRLM program, we chose to compare our fully implemented NRLM costs to those of BOB's study case. As BOB only presented per gallon costs graphically, we present both sets of cost estimates in graphical form in Figure 7.2.2.5-1.

Figure 7.2.2-8-1



As mentioned above, BOB projects relatively little 15 ppm NRLM fuel production compared to demand, and compared to that projected by EPA. From the BOB report, the difference in volume is caused by sizeable exports of high sulfur distillate from coastal refineries and a number of refinery shutdowns in the Midwest and Mountain regions of the U.S. From the information provided in the report, we cannot determine which refineries were projected to export or close. Therefore, we cannot perform any more precise comparison of per gallon costs than that provided in Figure 7.2.2.5-1. From this comparison, it is quite possible that BOB and EPA are projecting roughly similar costs for many individual refineries. In this case, the difference between the two cost curves would be the removal of a number of larger refineries with EPA-projected costs in the 4-8 cent per gallon range. This would compress the EPA cost curve into something more like the BOB cost curve. Even with this assumption, it appears that BOB is projecting that some refineries with NRLM production volumes of 10-15,000 bbl per day have costs in the 10-17 cent per gallon range. While above 10 cents per gallon, all the refineries in the EPA analysis have very small NRLM production volumes.

While BOB does not present any further detail regarding their per gallon costs, they do provide additional detail regarding their capital and operating costs. Regarding capital costs, BOB's projected capital investments by domestic refiners are summarized in Table 7.2.2-23.

Table 7.2.2-23
BOB and EPA Capital Cost of Desulfization

	Capital Investment ($ billion)	Production Volume (1000 bbl per day) *	Investment per bbl/day production
BOB			
Highway	7.15	2934	$2437
15 ppm NRLM (Study Case)	0.55	208	$2644
EPA			
Highway	6.18	3605	$1714
15 ppm NRLM	2.28	841	$2711

* BOB volumes are in 2010, EPA volumes are in 2014

The primary figures is this table that we want to focus on are those in the last column, which show the capital cost to add one barrel per day of 15 ppm fuel production capacity. As can be seen, BOB projects significantly higher costs for 15 ppm highway fuel. This is likely due to different assumptions regarding the probability that refiners will be able to revamp their existing 500 ppm hydrotreater to produce 15 ppm fuel. However, this difference will not be discussed further, as the cost of 15 ppm highway fuel is not the focus of this comparison.

Moving to NRLM fuel, BOB's estimated capital cost for 15 ppm NRLM fuel production are within a few percent of EPA's projection on a per barrel of production basis. BOB assumes that all refiners will use conventional hydrotreating technology to produce 15 ppm highway and NRLM fuel. EPA projects that roughly 60 percent of the volume of 15 ppm NRLM fuel produced will utilize advanced technology for the step from 500 ppm to 15 ppm. This would tend to reduce EPA's projected capital costs relative to those of BOB. However, our capital costs include the cost of new hydrogen plants and expanded sulfur plant capacity. BOB treated hydrogen as a utility and simply included the full cost of producing hydrogen (operating plus capital costs) in the price that refiners would have to pay. This difference would tend to increase our capital costs relative to those of BOB. Finally, BOB's source of capital costs was a study by the National Energy Technology Laboratory for EIA. NETL used many of the same sources which we cite in Section 7.2.1 for the capital cost of conventional hydrotreating. However, NETL increased their capital cost projections from these sources by 33 percent, based on discussions with refiners. (The details of these discussions were not provided, so no comment can be made about the appropriateness of this adjustment.) Therefore, it is likely that BOB's primary capital cost inputs for conventional hydrotreating are roughly 33 percent higher than those described in Section 7.2.1 above. As the NETL study dates from mid-2001, it was unable to incorporate later information, such as the successful operation of the Process Dynamics IsoTherming demonstration unit. Overall, we believe that our capital cost estimates are reasonable in light of the BOB analysis. First, for conventional hydrotreating, we used the same primary cost inputs. Second, the 33 percent adjustment by NETL was based on discussions with refiners which we cannot evaluate. Third, it is appropriate to include advanced technologies which have been demonstrated at the commercial level. Fourth, the inclusion of capital costs for hydrogen plants and expanded sulfur plants provides a more complete estimate of the total capital investment required by the refining industry and their suppliers.

Regarding operating costs, hydrogen costs tend to dominate these costs. Thus, we will focus our comparison there. Hydrogen costs are a function of the volume of hydrogen needed to desulfurize a gallon of diesel fuel and the price of hydrogen. Regarding the former, BOB based their hydrogen consumption estimates on a number of studies, including one which we cite in Section 7.2.1 (Figures 31 in the BOB report). One of these estimates, that made by IFP, projects hydrogen consumptions over twice those of the other studies. We evaluated this estimate in our Draft and Final RIAs for the 2007 highway diesel rule, along with a number of other estimates. There, based on changes in other fuel properties, we determined that this estimate was based on very conservative assumptions concerning the level of aromatic saturation and modest cracking that would occur when desulfurizing diesel fuel to 7 ppm sulfur and decided not to use it any further. As four out of five vendors projected that this level of saturation would not be necessary, we decided not to incorporate this estimate into our cost methodology.

The IFP estimates appear to have a significant impact on the BOB hydrogen consumption estimates, as BOB's hydrogen consumption model over-predicts all of the other data used to develop the model. Also, subsequent discussions with IFP staff indicate that their more recent estimates (the original estimate was made prior to 2000) are more in line with those of the other vendors.

In Figure 9 of the BOB study, they present their estimated hydrogen consumption for three different diesel fuel compositions for a grass roots conventional hydrotreater designed to produce 15 ppm diesel fuel. We used our methodology developed in Section 7.2.1 to estimate hydrogen consumption for these same feeds for a grass roots hydrotreater. Table 7.2.2-24 shows both the EPA and BOB estimates of hydrogen consumption.

Table 7.2.2-24
EPA and BOB 15 ppm Hydrogen Consumption: Grassroots Diesel Hydrotreater

BOB Feed Case	Feed Composition	Hydrogen Consumption, scf/bbl	
		EPA	BOB
1	100% Straight Run	240	510
2	50% Straight Run, 35% LCO 15% LCGO	582	778
3	70% LCO, 30% LCGO	1025	1091

As can be seen, the BOB estimates are significantly higher than our estimates, particularly for the 100 percent straight run distillate. We compared BOB's 510 scf/bbl estimate for this case with the hydrogen consumptions which BOB presents in an appendix where it compares the predictions of its hydrogen model to the vendor estimates (Figure 31 in the BOB report). There, BOB shows five cases where the diesel fuel being hydrotreated is 100 percent straight run. BOB shows that its hydrogen model predicts hydrogen consumptions of 244-268 scf/bbl for these feedstocks. This is roughly half that which they show in Figure 9. No explanation for this discrepancy is presented in the report. However, if the hydrogen consumptions shown in BOB's Figure 9 were actually used in their cost estimations, then they appeared to have over-estimated hydrogen costs even compared to their own model validations.

With respect to hydrogen costs, BOB assumed that hydrogen would cost twice the cost of natural gas. They did not state whether this was on a Btu basis, or a scf basis. Other information presented in the study implies that it was on a scf basis. As BOB projected future natural gas prices of roughly $3 per mmBTU (equivalent to $3 per 1000 scf), this implies that BOB projected hydrogen costs of $6 per 1000 scf. In Section 7.2.1, we describe how we estimate hydrogen costs. There, we use a future natural gas price of $4.15 per mmBtu, well above that used by BOB. However, using this natural gas price, we estimate hydrogen costs of $2.20-3.90 per 1000 scf. As described in Section 7.2.1, we base these costs on a new hydrogen plant typical of the size of hydrogen plants in the region today, or by an even mix of new plants or third party plats for the hydrogen supplied in the Gulf Coast. We also adjusted for variations in natural gas costs, typical plant capacities, location factors and off-site factors all differing according to the region of the country in which the refinery is located. It is unclear where BOB obtained its rule of thumb on hydrogen prices. It may have been accurate when natural gas prices were much lower than today and capital costs comprised a much larger percentage of total costs. However, this rule of thumb does not appear to be appropriate at today's natural gas prices. Thus, it appears, though one cannot be sure given the lack of detail in the report, that BOB significantly over-estimated hydrogen costs.

7.3 Cost of Lubricity Additives

Our evaluation of the potential impact of the non-highway diesel sulfur standards on fuel lubricity is described in Section 5.9. We conclude that the increased need for lubricity additives resulting from the these sulfur standards will be similar to that for highway diesel fuel meeting the same sulfur standard. In the HD2007 rule, we conservatively estimated that all diesel fuel meeting a 15 ppm sulfur standard will use lubricity additives at a cost of 0.2 cents per gallon.[55] Consistent with the estimated cost from the increased use of lubricity additives in 15 ppm highway diesel fuel, we have included a charge of 0.2 cents per gallon in our cost calculation to account for the increased use of lubricity additives in 15 ppm NRLM diesel fuel. This lubricity additive cost applies to the affected NRLM diesel fuel pool beginning in 2010.

In estimating lubricity additive costs for 500 ppm diesel fuel, we conservatively assumed that if diesel fuel is required to have its lubricity improved through the use of additives, that the same additive concentration will be needed both for 15 ppm and for 500 ppm diesel fuel. However, the vast majority of 500 ppm diesel fuel does not require the use of lubricity additives. We assumed that 5 percent of all 500 ppm diesel fuel would need a lubricity additive. Based on these assumptions, we estimate that the cost of additional lubricity additives for the affected 500 ppm NRLM diesel fuel is 0.01 cents per gallon. The amount of lubricity additive needed increases substantially as diesel fuel is desulfurized to lower levels. Also, based on the industry input (see Section 5.9) it is likely that substantially less than 5 percent of 500 ppm diesel fuel outside of California requires a lubricity additive. We therefore believe 0.01 cents per gallon represents a conservatively high estimate of the cost of lubricity additives for affected volume of 500 ppm nonroad, locomotive, and marine diesel fuel. Although the actual cost will likely be considerably less, we have no information to better quantify the percentage of 500 ppm diesel fuel currently treated with a lubricity additive or the appropriate additive treatment rate. The 0.01 cents per gallon cost for a lubricity additive applies to the affected non-highway diesel pool (NRLM) until the 15 ppm sulfur standard takes effect in 2010.

EIA FOKS/AEO NRLM Fuel Demand Scenario:

As discussed in Section 5.9, lubricity costs vary primarily with sulfur level, as the sulfur level affects the degree of hydrotreating applied, which in turn results in changes to other fuel properties which affect lubricity. Thus, lubricity costs do not vary with implementation date or type of diesel fuel market (i.e., highway, nonroad, locomotive or marine). Thus, as the sulfur level of various diesel fuels change under the alternative control options, the lubricity costs vary accordingly. However, the cost per gallon for 500 ppm fuel will remain 0.01 cent per gallon and the cost for 15 ppm fuel will remain 0.2 cent per gallon.

7.4 Cost of Distributing Non-Highway Diesel Fuel

A summary of the distribution costs that we project will result from the implementation of the NRLM sulfur standards is contained in Table 7.4.-1. How we arrived at these cost estimates is described in the following sections.

TABLE 7.4.-1
SUMMARY OF DISTRIBUTION COSTS (CENTS PER GALLON) *

Cause of Increase in Distribution Costs	Time Period Over Which Costs Apply			
	2007-2010	2010-2012	2012-2014	After 2014
Distribution of Additional NRLM Volume to Compensate for Reduction in Volumetric Energy Content	0.08	0.1	0.1	0.1
Distillate Interface Handling	0	0.4	0.4	0.8
New Product Segregation as Bulk Plants	0.1	0.1	0.1	0.1
Heating Oil and L&M Fuel Marker	0.01	0.02	0.01	0.01
Total	0.2	0.6	0.6	1.0

* Costs have been rounded to one significant figure.

7.4.1 New Production Segregation at Bulk Plants

Section 5.4.1. evaluates the potential for additional product segregation in each segment of the distribution system. As discussed in Section 5.5.1.2., approximately 1,000 bulk plants could add an additional storage tank and demanifold their delivery truck(s) to handle an additional diesel product.

In its comments to the government/industry panel convened in accordance with the Small Business Regulatory Enforcement Act (SBREFA), the Petroleum Marketers Association of America (PMAA) stated that, depending on the location, the cost of installing a new diesel storage tank at a bulk plant ranges from $70,000 to $100,000. To provide a conservatively high estimate of the cost to bulk plant operators, we used an average cost of $90,000. This is consistent with the information we obtained from a contractor working for EPA (ICF Kaiser) on the installed cost of a 20,000-gallon storage tank, which is the typical tank size at bulk plant facilities. Demanifolding of the bulk plant operators delivery truck involves installing an internal bulkhead to make two tank compartments from a single compartment. To help control contamination concerns, we also estimated that an additional fuel delivery system will be installed on the tank truck (i.e., that there will be a separate delivery system for each fuel carried by the delivery truck). The cost of demanifolding a tank truck and installing an additional fuel delivery system is estimated at $10,000, of which $6,000 is the cost of installing a new fuel delivery system.[56]

In the NPRM, we estimated that each bulk plant that needed to install a new storage tank would need to demanifold a single tank truck. Thus, the NPRM estimated the cost per bulk plant would be $100,000. Fuel distributors stated that the assumptions and calculations made by EPA in characterizing costs for bulk plant operators seem reasonable. However, they also stated that our estimate that a single tank truck would service a bulk plant is probably not accurate. No suggestion was offered regarding what might be a more appropriate estimate other than the number is likely to be much greater. Part of the reason why we estimated that only a single tank truck would need to be demanifolded, is that we expected that due to the seasonal nature of the demand for heating oil versus nonroad fuel, it would primarily only be at the juncture of these two seasons that both fuels would need to be distributed in substantial quantities. We also expected that the small demand for heating oil in the summer and the small demand for nonroad fuel in the winter could be serviced using a single demanifolded truck. The primary fuel distributed during a given season would be distributed by single compartment tank trucks. During the crossover between seasons, bulk plant operators would switch the fuel to which such single compartment tank trucks are used from nonroad to heating oil and back again.[NN] Nevertheless, we agree that some of the subject bulk plant operators would likely be compelled to demanifold more that a single tank truck. Lacking additional specific information, we believe that assuming that each bulk plant operator demanifolds three tank trucks will provide a conservatively high estimate of the cost to bulk plant operators due to this rule.

If all 1,000 bulk plants were to install a new tank and demanifold three tank trucks, the cost for each bulk plant would be $120,000, and the total one-time capital cost would be $120,000,000. To provide a conservatively high estimate of the costs to bulk plant operators, we are assuming that all 1,000 bulk plants will do so. Amortizing the capital costs over 20 years, results in a estimated cost for tankage at such bulk plants of 0.1 cents per gallon of affected NRLM diesel fuel supplied. Although the impact on the overall cost of the program is small, the cost to those bulk plant operators who need to put in a separate storage tank may represent a substantial investment. Thus, we believe many of these bulk plants will search out other arrangements to continue servicing both heating oil and NRLM markets such as an exchange agreement between two bulk plants that serve a common area.

The need for additional storage tanks at terminals to handle products produced from pipeline interface is discussed in Section 7.4.1.2. of this RIA. Aside from the costs described above for bulk plant operators, and those discussed in Section 7.4.1.2, we project that there will be no substantial need for additional storage tanks or other facility changes to segregate additional products.

EIA FOKS/AEO Nonroad Fuel Volume Scenario:

Using EIA nonroad fuel volumes rather than our primary fuel volume scenario which utilized the EPA NONROAD model for nonroad fuel consumption does not affect our assessment of product distribution patterns on which the above estimate of the costs to bulk plant operators are based. Therefore, our estimate of the costs to bulk plant operators under the EIA nonroad fuel volume scenario is the same as that under our primary fuel volume scenario. However, the

[NN] To avoid sulfur contamination of NRLM fuel, the tank compartment would need to be flushed with some NRLM fuel prior to switching from carrying heating oil to NRLM fuel.

volume of affected NRLM to which these costs are attributed is reduced somewhat under the EIA nonroad volume scenario, and consequently the cost per gallon is directionally higher than under our primary fuel volume scenario. Nevertheless, because the costs are small, this does not result in a material change to our estimate of 0.1 cents per gallon of affected NRLM diesel fuel supplied.

Because our assessment of product distribution patterns is not different under the EIA nonroad volume scenario from that under our primary scenario, we also project that aside from the costs described above for bulk plant operators, and those discussed in Section 7.4.1.2, there will be no substantial need for additional storage tanks or other facility changes to segregate additional products.

7.4.2 Reduction in Fuel Volumetric Energy Content

We project that desulfurizing diesel fuel to 500 ppm will reduce volumetric energy content (VEC) by 0.7 percent. The cost of which is equivalent to 0.08 cent per gallon of affected NRLM fuel. We project that desulfurizing diesel fuel to 15 ppm will reduce volumetric energy content by an additional 0.5 percent. This will increase the cost of distributing fuel by an additional 0.05 cents per gallon, for a total cost of 0.13 cents per gallon of affected 15 ppm NRLM fuel. Following is a discussion of how we arrived at these estimated costs.

The reduction in VEC due to desulfurization of NRLM fuel to meet the standards in this rule depends on the desulfurization process used. We project that conventional hydrotreating will be the desulfurization process used to desulfurize NRLM to meet the 500 ppm sulfur standard. However, as discussed in Chapter 5, we project that new technology (Process Dynamics Isotherming) will be used as well to desulfurize NRLM to meet the 15 ppm standard. These processes have different projected impacts on VEC, as discussed in Chapter 5.2. and shown in Table 7.4-2.

Table 7.4-2
Impact of Desulfurization on the Volumetric Energy Content of Diesel Fuel

Process	NRLM Fuel Volume Processed		Reduction in VEC High Sulfur to 500 ppm	Reduction in VEC 500 ppm to 15 ppm
	500 ppm Standard	15 ppm Standard		
Hydrodesulfurization	100 %	40 %	0.7%	0.7%
Process Dynamics Isotherming	0 %	60 %	NA	0.4%
Overall for NRLM Pool	-	-	0.7%	0.5%

The difference between the price of non-highway diesel fuel to end-users and the price to resellers provides an appropriate estimate of the cost of distributing non-highway diesel fuel. The Energy Information Administration (EIA) publishes data regarding the price excluding taxes of high-sulfur No. 2 diesel fuel to end-users versus the price to resellers. We used the five-year average of the difference between these two prices to arrive at an estimated typical cost of distributing NRLM fuel to the end-user. In the NPRM, we used data from 1995 through 1999 to arrive at an estimated distribution cost of 10 cents per gallon. For this final rule, we used 1997 through 2001 data to update this analysis. The EIA data that we used to estimate the cost of distributing NRLM fuel is presented in Table 7.4-3.

Table 7.4-3
Cost of Distributing High-Sulfur No. 2 Diesel Fuel[a] (cents per gallon, excluding taxes)

Year	Sales to Resellers	Sales to End Users	Difference Between Sales to End Users and Sales to Resellers
1995	52.4	61.4	9.0
1996	63.9	73.2	9.3
1997	60.2	69.8	9.6
1998	43.7	55.5	11.8
1999	51.9	62.0	10.1
2000	87.5	98.1	10.6
2001	77.1	89.2	12.1
Average of 5 Most Recent Years	54.4	64.4	10.8

[a] Energy Information Administration, Annual Energy Review 2003

Based on the information in Table 7.4-3, we assumed a 10.8 cent per gallon cost of distributing diesel for the purposes of estimating the increased distribution costs due to reduced VEC. We derived our estimates of the increase in distribution costs under each step of the NRLM sulfur program by multiplying the applicable percent reduction in VEC by 10.8 cents per gallon.

Since the difference in price at the refiner rack versus that at retail also includes some profit for the distributor and retailer, its use provides a conservatively high estimate of distribution costs. The fact that a slightly less dense (lighter, less viscous) fuel requires slightly less energy to be distributed also indicates that this estimate is conservative.

EIA FOKS/AEO Nonroad Fuel Volume Scenario:

Using EIA nonroad fuel volumes rather than our primary fuel volume scenario which utilized the EPA NONROAD model for nonroad fuel consumption does not affect our estimate of the increased distribution costs related to the reduction in VEC. Thus, the 0.08 and 0.13 cent per gallon costs for 500 ppm and 15 ppm fuel do change.

7.4.3 Handling of Distillate Fuel Produced from Pipeline Interface

As discussed in Section 5.1, the shipment of 30 ppm gasoline, 15 ppm diesel fuel, jet fuel and, in some cases, 500 ppm locomotive and marine fuel and high sulfur heating oil, will produce commingled distillate fuel at the interfaces of each batch. In Section 5.1, we estimate the volumes of each interface and how the fuel distribution system could dispose of each interface in order to maximize profits (i.e., minimize costs). Basically, interfaces containing some gasoline are presumed to go to existing transmix facilities. The distillate fuel produced by these transmix processors will contain a mixture of heavy naphtha, jet fuel and 15 ppm diesel fuel. We project that this mixture will contain 500 ppm sulfur or less and can thus be sold as 500 ppm diesel fuel of high sulfur heating oil.

The other interface which will not be able to be blended into either of the adjacent batches is that between jet fuel and 15 ppm diesel fuel. In the Northeast and along the Colonial and Plantation pipelines, we assume that this distillate interface will be added to the heating oil tank, which will continue to be distributed throughout the distribution system. Elsewhere, we do not believe that heating oil will be distributed in pipelines. We assume the interface containing jet fuel and 15 ppm diesel fuel will not be shipped to transmix processors. Interface processors basically distill transmix into a lighter than average naphtha component and a lighter than average distillate component.[OO] This distillate contains all of the original jet fuel and No. 2 distillate (both highway and high sulfur) fuel. Adding an interface consisting of jet fuel and No. 2 distillate to the current transmix tank and running this through a distillation column would only result in all of this jet-distillate interface flowing to the bottoms of the column. The additional distillate would also affect the operation of the distillation column, as they are typically designed for a certain fraction of the feedstock going overhead. Thus, we believe that it would be more economical for terminals to segregate this No. 1/No. 2 distillate interface from transmix in a separate storage tank. As described in Section 7.1, we estimate that this interfacial material will likewise meet a 500 ppm sulfur cap. Thus, the terminal can ship this interface to consumers in either the 500 ppm diesel fuel or heating oil markets.

The disposition of this 500 ppm interface fuel is described in Section 5.1. Generally, we assumed that this material would be sold to the heating oil first, then into the 500 ppm highway fuel market (through 2010), to the 500 ppm NRLM market (the nonroad fuel market through 2014), and finally into the L&M diesel market (after 2014). An exception to this applies in the Northeast/Mid-Atlantic Area, where this interface cannot be sold into the nonroad fuel market after 2010, nor into the L&M fuel market after 2012. If the volume of this 500 ppm interface exceeds the demand for 500 ppm diesel fuel and heating oil, then we assumed that it would have to be shipped back to a refiner and reprocessed to meet the 15 ppm cap.

[OO] Normally, one thinks of transmix processing as separating transmix back into its original gasoline and distillate components. However, the lighter compounds in original distillate fuel inevitably mix with the heavier compounds in the original gasoline and lower the octane of this heavy gasoline dramatically. Due to the cost of making up for this octane loss, transmix processors typically send the heavier gasoline compounds to the distillate half of their product..

The cost of disposing of this 500 ppm distillate material will likely vary geographically, depending on the size of the heating oil market. In the Northeast, the only cost of disposing of this interface will be the value lost by selling former jet fuel and 15 ppm diesel fuel as heating oil. This cost is already included in our refining costs, as there, we increased the volume of 15 ppm diesel fuel which had to be processed due to losses during distribution. We estimate that about 80% of the diesel fuel shipped to PADD 1 is sold in areas with large heating oil markets. In the remainder of the country, the heating oil market is more limited. Matching any high sulfur heating oil and users of this fuel will be more difficult and costly in terms of transportation.

Prior to mid-2010, 500 ppm interface can simply be added to the 500 ppm NRLM fuel storage tank, which should exist at most terminals, or the 500 ppm highway fuel storage tank, if this fuel is being stored at that terminal. Thus, there should be essentially no cost related to disposing of this interface material.

From mid-2010 through 2012, 500 ppm fuel can no longer be sold to the highway fuel market. Also, we do not expect that small refiner 500 ppm nonroad fuel and 500 ppm L&M fuel will be widely distributed. Thus, this interface material will require its own storage tank. The 500 ppm interface can be sold to users of NRLM fuel, as well as heating oil. The only restriction is that it cannot be used in nonroad equipment equipped with emission controls requiring 15 ppm fuel, nor in nonroad engines in general within the Northeast/Mid-Atlantic Area. Most nonroad fuel users only have one fuel storage tank on-site. Or, if they have more than one tank, it is because their operations cover long distances (e.g., farms, quarries, etc.) and multiple tanks reduce the time it takes to move the equipment to the refueling station. Thus, nonroad equipment users which have purchased even one new piece of equipment requiring 15 ppm fuel will often desire to purchase 15 ppm fuel for all their equipment. Thus, the number of NRLM fuel users willing to accept 500 ppm fuel will gradually diminish from 2010 to 2014. This will increase the distance that the fuel will have to be shipped to find a purchaser.

We estimate that the cost to store this 500 ppm fuel at a terminal will vary by terminal. At those terminals able to receive jet fuel and 15 ppm diesel fuel from the heart of the pipeline batches passing by it, the only distillate-distillate interface will be from washing lines to protect jet fuel and diesel fuel quality. This material might be stored in a small tank, but will most likely simply be added to the existing transmix tank. Thus, incremental storage costs will likely be negligible, but transmix volume will increase. Terminals near the end of pipeline or pipeline branch will receive a relatively large volume of distillate-distillate interface. Some of these terminals will likely be able to use the tank that was previously used to hold heating oil or 500 ppm NRLM fuel or the tank used to hold 500 ppm L&M diesel fuel from 2010-2012. However, in other cases it may require some new tankage. Economics will likely encourage the off-loading at terminals with existing tankage. However, proximity to a large 500 ppm market (L&M fuel, heating oil) will also likely be a factor.

Depending on the size of the tank, storage costs vary substantially. Smaller tanks can cost $5 per gallon of capacity, while very large tanks might only cost $20 per barrel ($0.5 per gallon). Amortizing these costs over 15 years of weekly shipments of 60% of capacity at a 7% rate of return, storage costs range from 0.2-1.6 cents per gallon in those cases requiring a new tank. It is not possible to estimate a precise distribution of tank sizes and thus, costs. We assume that the availability of existing tankage will balance the need for smaller tanks on average and that the average storage cost will be near the lower end of this range, 0.4 cents per gallon. In addition, there is an inventory cost to have this stored fuel on hand. At a 7% rate of return, assuming that the tank is half full on average, for fuel at $1 per gallon, the carrying cost is 0.1 cent per gallon. Thus, the total storage cost is roughly 0.5 cent per gallon.

There is also the potential for increased storage costs at transmix processing facilities. The increased volume of distillate-distillate interface added to transmix will likely be very small relative to the total volume of gasoline-distillate interface. Thus, existing tankage should be sufficient. However, currently, transmix processors often ship their distillate production into tankage at terminals which are usually located adjacent to the processing facility. After 2010, the only 500 ppm fuel that would be stored at most of these terminals would be interface, and all terminals after 2012, as discussed above. These terminals may have to increase their storage capacity beyond that necessary to handle interface received directly from the pipeline and line washing. We project that the incremental cost to store this transmix interface will be the same 0.5 cent per gallon as that projected above for non-transmix interface. Since all the distillate-distillate interface will either be stored as a distinct fuel at the terminal or combined with transmix and processed, the overall storage cost for all distillate-distillate interface is 0.5 cent per gallon.

We expect that there will be an additional cost of shipping this 500 ppm fuel to those who can use it. Nonroad fuel markets will likely be served by truck, as is the case today. Locomotive and most marine markets will likely be served by rail. Shipping this 500 ppm fuel will not have the economies of scale of the current nonroad market or the future 15 ppm nonroad market. Trucks will have to spend more time driving between stops or a smaller compartment will have to be added to the tank. In either case, costs will increase. Rail shipments will also be smaller than today, increasing handling costs. We estimate that the additional cost of delivering 500 ppm interface to these NRLM users without 2011 and later nonroad equipment will cost 1.5 cents per gallon. This cost is equivalent to increasing the shipping distance by 45 miles by truck and 100 miles by rail.[PP] Combined with storage costs, distributing this fuel to NRLM users will cost 2.0 cents per gallon.

In those cases where the 500 ppm interface is sold to the heating oil markets outside of the Northeast, we expect that the costs will be larger. Heating oil users outside of the Northeast are not evenly distributed geographically. The interface will also not be evenly distributed geographically. Thus, the interface may not be removed from the pipeline near the users of heating oil. Also, we expect that this fuel will have to be transported by truck. We project that the additional mileage will be roughly 85 miles and cost 3.0 cents per gallon. Combined with storage costs, distributing this fuel to heating oil users outside of the Northeast will cost 3.5 cents per gallon.

[PP] Trucking and rail costs of 0.035 and 0.012-0.2 cent per gallon, respectively from: "Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel", Robert E. Cunningham, Thomas R. Hogan, Joseph A. Loftus, and Charles L. Miller, Turner and Mason and Co. Consulting Engineers, February 2000.

Finally, there are some PADDs where the NRLM and heating oil markers are not large enough to handle all of the 500 ppm interface generated. In these cases, the interface will have to be shipped back to a refinery by truck, reprocessed through the refiner's hydrotreater and shipped back to the fuel market with the rest of the refiner's production. The storage cost of 0.5 cent per gallon at terminals and transmix operators will still apply, since it will still likely to be less costly to keep this interface segregated from gasoline-distillate transmix. (Transmix will be sent to transmix processors, while the jet-distillate interface will have to be sent to refineries with excess hydrotreating capacity.) We estimate that most of this distillate will be shipped roughly 200 miles by rail and cost 3.0 cents per gallon. Desulfurizing this material to 15 ppm will be technically simple, since it will consist of heavy naphtha, jet fuel and 15 ppm diesel fuel. The two lighter fuels do not contain any stearically hindered molecules. However, refiners generally do not add material into the middle of their distillate production train. There will likely be a tank storing diesel fuel prior to desulfurization, where straight run, LCO and other cracked stocks are mixed. However, there might not be easy access to this tank from outside of the refinery. Thus, we expect that the handling costs will far exceed the desulfurization costs. We project a total cost for reprocessing of 4.5 cents per gallon. Finally, this re-processed fuel must be shipped out again, usually via pipeline. We project this last distribution cost to be 2 cents per gallon. Thus, the total cost for interface which must be reprocessed is 10 cents per gallon.

From mid-2012 through 2014, very little changes from 2010-2012. The only change is that downgraded distillate can no longer be sold to the L&M fuel market in the Northeast/Mid-Atlantic Area. Instead this fuel shifts to the heating oil market. As this is a minor change, we assume that all of the costs of distributing the downgraded distillate to the various markets from 2012-2014 remain the same as in 2010-2014.

In 2014, when 500 ppm fuel can no longer be sold to nonroad equipment users, we project that the transportation distance to L&M fuel users will nearly double, as will the transportation cost, to 2.5 cents per gallon. Outside of PADDs 1 and 3, we estimate that the downgraded material will comprise 70-100% of the L&M market, so, given the above methodology, the downgraded material will have to move to nearly every L&M refueling site. With storage costs of 0.5 cents per gallon, the total cost of distributing downgraded material to the L&M fuel market will be 3.0 cents per gallon.

Likewise, we project that the transportation distance to heating oil users will also increase. However, we do not believe that these distances will double, because the increase in downgraded material going to the heating oil market is smaller on a relative basis than for the L&M fuel market. Thus, we project that the transportation distance to heating oil users will increase to roughly 130 miles and cost 4.5 cents per gallon. With storage costs of 0.5 cents per gallon, the total cost of distributing downgraded material to the heating oil market will be 5.0 cents per gallon. The cost to reprocess distillate to meet a 15 ppm cap will remain at 10 cents per gallon.

In Section 7.1, we estimated the volume of downgraded jet fuel and diesel fuel which would be sold to the nonroad, L&M and heating oil markets prior to the NRLM rule (Table 7.1.3-9), from 2007-2010 (Table 7.1.3-14), from 2010-2012 (Table 7.1.3-17), from 2013-2014 (Table 7.1.3-18) and in 2014 and beyond (Table 7.1.3-19). We likewise estimate the volumes of fuel which must be reprocessed to meet a 15 ppm cap. These volumes are summarized in Table 7.4.4, along with the cost per gallon of storing and shipping this interface to the various fuel markets.

Table 7.4.4
Annual Costs Associated With Distribution of Distillate Interface

Jet-Distillate Interface Sent to:	Volume Affected (million gallons/yr)	Cost per Gallon	Annual Cost (million)
Baseline			
NRLM Market	247	2.0 cents	$5
Heating Oil Market	219	3.5 cents	$8
Reprocessed	0	10.0 cents	0
Total	---	---	$13
2010-2012			
NRLM Market	1,395	2.0 cents	$30
Heating Oil Market	1,045	3.5 cents	$32
Reprocessed	0	10.0 cents	0
Total	---	---	$63
2012-2014			
NRLM Market	1,395	2.0 cents	$28
Heating Oil Market	1,045	3.5 cents	$37
Reprocessed	0	10.0 cents	0
Total	---	---	$65
2014 and beyond			
NRLM Market	1,336	3.0 cents	$40
Heating Oil Market	885	5.0 cents	$44
Reprocessed	335	10.0 cents	$34
Total	---	---	$118

Table 7.4.4 also shows the annual cost associated with each fuel market, which is simply the product of the fuel volume and the cost per gallon (converted from cents to dollars). The annual cost due to the NRLM rule from 2007-2010 is $47 million, which is the total cost of $61 million less the $14 million cost occurring prior to the rule. Likewise, the cost due to the NRLM rule in

2010-2012, 2012-2014 and 2014 and beyond is $63, $65, and $102 million, respectively. The total affected NRLM fuel volume is 12.4 billion gallons in 2010, 12.8 billion gallons in 2012 and 13.4 billion gallons in 2014 (all three figures represent fuel production and demand grown to 2014). Thus, these annual costs represent incremental costs of 0.40, 0.41 and 0.79 cent per gallon from 2010-2012, 2012-2014, and 2014 and beyond, respectively.[QQ]

We anticipate that there will be no other significant distribution costs associated with the NRLM sulfur standards in this rule beyond those described in Sections 7.4.1, 7.4.2, and 7.4.3. We do not expect the need for additional storage tanks beyond that discussed in Sections 7.4.1., and 7.4.3., or a significant increase in pipeline downgrade or transmix volumes beyond the modest potential increase in tranmix volume discussed in Section 7.4.3. As discussed in Section 7.4.5., we are projecting costs associated with the need to install fuel marker injection equipment at a limited number of refineries, transmix processors, and terminals

Operators of bulk plants and tank trucks who previously handled only high-sulfur diesel fuel will need to begin observing practices to limit sulfur contamination during the distribution of 500 ppm and 15 ppm diesel fuel. However, these practices are either well established or will be for compliance with the 15 ppm highway standard in 2006. Furthermore, they are primarily associated with purging storage tanks and fuel delivery systems of high-sulfur diesel fuel before handling 500 ppm and 15 ppm diesel fuel. Training employees will be necessary to stress the importance of consistently and carefully observing practices to limit sulfur contamination. However, we estimate the associated costs will be minimal. In addition, we are estimating that most of the affected bulk plant operators will install dedicated storage tanks and truck delivery systems. This obviates the need for much of the cautionary actions necessary to limit sulfur contamination when both low and high-sulfur diesel fuel is carried by the same marketer.

As discussed in Section 5.6, the vast majority of the fuel distribution system (primarily pipeline and terminal facilities) will already have optimized their facilities and procedures to limit sulfur contamination for distributing 15 ppm sulfur fuel due to the need to comply with the highway diesel fuel program in 2006. The costs associated with this optimization process were accounted for in the HD2007 Regulatory Impact Analysis.[57] Highway diesel fuel and nonroad diesel fuel meeting a 15 ppm sulfur specification will share the same distribution system until nonroad diesel fuel is dyed to meet IRS requirements as it leaves the terminal. We therefore do not expect any additional actions or costs to optimize the distribution system to limit sulfur contamination during the distribution of 15 ppm nonroad diesel fuel.

EIA FOKS/AEO Nonroad Fuel Volume Scenario: We followed the same methodology for estimating downgrade-related distribution costs for this scenario as our primary fuel volume scenario which utilized the EPA NONROAD model for nonroad fuel consumption. Using EIA nonroad fuel volumes, as described in Section 7.1 above, reduces the volume of NRLM fuel demanded in each PADD, except PADD 3. Consequently, the volumes of heating oil consumed

[QQ] The increase in cost in 2014 is due to the inability to use downgraded material in the nonroad market. If the $105 million cost in 2014 is spread only over the nonroad fuel market, the cost per gallon is 1.0 cents.

increase everywhere except PADD 3. This reduces the contribution of the volume of downgraded material to the NRLM and heating oil markets substantially. Particularly in PADD 2, instead of downgraded material comprising a major portion of the NRLM and heating oil markets, it comprises roughly 33%. We believe that this will make it easier for terminals to find heating oil consumers and reduce the transport distance to these users. Thus, for PADD 2, we reduced the cost of distributing interface to the heating oil market to that of the NRLM or L&M markets (depending on the time period), or 2 cents per gallon. However, the volume of NRLM fuel over which the increased transportion costs are spread also decreases. The net result is that the cost of distributing interface material from 2010-2014 remains unchanged at 0.4 cent per gallon. However, the cost after 2014 decreases from 0.79 to 0.56 cents per gallon.

7.4.4 Fuel Marker Costs

In the NPRM we estimated that the cost to blenders of the heating oil marker in bulk quantities would translate to 0.2 cents per gallon of fuel treated with the marker. This estimate was based on the fee charged by a major pipeline to inject red dye at the IRS concentration into its customers diesel fuel. Conversations with marker manufactures prior to the publication of the NRLM indicated that the cost to treat fuel with either of the markers considered in the NPRM would be lower than the costs to treat non-highway diesel fuel with red dye to meet IRS requirements. We used this estimate because we lacked specific cost information on the proposed marker, there was uncertainty regarding the specific marker that we would require, and we believed that it provided a conservatively high estimate of cost for any of the markers under consideration. Since the proposal, we received input from a major distributor of fuel markers and dyes, regarding the cost of bulk deliveries of the specified fuel marker (solvent yellow 124) to terminals which translates to a cost of 0.03 cents per gallon of fuel treated with the marker. The volume of heating oil that we expect will need to be marked has also decreased substantially from that estimated in the NPRM due to the provisions applicable in the Northeast/Mid-Atlantic Area and Alaska. We estimate that 1.4 billion gallons of heating oil will be marked annually, for an annual marker cost of $425,000.[RR] In the NPRM, this marker cost applied to heating oil for just three years, but then continued on for another four years for locomotive and marine diesel fuel. Under this final rule, the marker requirement for locomotive and marine diesel fuel is applicable only from 2010 though 2012, and only outside of the Northeast/Mid-Atlantic Area and Alaska. However, the marker requirements for heating oil continues indefinitely.

The NPRM projected that there would be no capital costs associated with the proposed marker requirement. We proposed that the marker would be added at the refinery gate, and that the current requirement that non-highway fuel be dyed red at the refinery gate be made voluntary. Thus, we believed that the refiner's additive injection equipment that is currently used to inject red dye into off-highway diesel fuel could instead be used to inject the fuel marker. As a result of the allowance provided in this final rule that the marker may be added at the terminal rather than the refinery gate, and our reevaluation of the conditions for dye injection at

[RR] The costs of the marker requirement for L&M diesel fuel are discussed at the end of this section.

the refinery, we are now assessing capital costs for terminals and refiners related to compliance with the marker requirements.

Except for fuel that is distributed directly from a refiner's rack, this final rule allows the marker to be added at the terminal rather than at the refinery (see Section IV.D. of the preamble for a discussion of the fuel marker requirements).[SS] We expect that except for fuel dispensed directly from the refinery rack, the fuel marker will be added to at the terminal to avoid the potential for marked fuel to contaminate jet fuel in during distribution by pipeline. Terminals that need to inject the fuel marker will need to purchase a new injection system, including a marker storage tank and a segregated line and injector for each truck loading station at which fuel that is required to contain the marker is dispensed. Terminals will still be subject to IRS red dye requirements, and thus will not be able to rededicate such injection equipment to inject the fuel marker. Due to concerns regarding the need to maintain a visible evidence of the presence of the fuel marker, this final rule also contains a requirement that any fuel which contains the fuel marker also contains visible evidence of red dye. Furthermore, there is little chance to adapt parts of the red dye injection system (such as the feed lines and injectors) for the alternate injection of red dye and the fuel marker due to concerns that fuel which must not contain the marker might become contaminated with the marker.

We received information from various sources to estimate the cost of installing new injection equipment to handle the heating oil marker. Our first source of information was the Independent Fuel Terminal Operators Association (IFTOA). IFTOA stated that the cost for new additive injection equipment would be $40,000 per loading arm used to deliver heating oil to tank trucks with the cost for some terminals being as much as $250,000 (for 6-7 loading arms).

We also sought information from manufacturers of additive injection equipment. Titan industries and Lubrizol, leading manufacturers of such equipment, provided information on the uninstalled cost of the necessary hardware which is summarized in the following Table 7.4.5.[58].

Table 7.4.5
Uninstalled Cost of Additive Injection Hardware

Item	Cost
500 gallon Skid Storage Tank	$3,700 - $8,000
Rack Mounted Pump Assembly	$5,000 - $9,000[1]
Chemical Injector	$2,500-$2,900
Total	$11,200-$19,900

1. Depending on whether a single or a double pump assembly is used. The second pump serves as a back-up.

[SS]A refinery rack functions similar to a terminal in that it distributes fuel by truck to wholesale purchaser consumers and retailers.

The lower end tank cost was more consistent with our previous experience regarding tank costs. Consequently we elected to use $4,000 as a reasonable estimate of the uninstalled cost of an additive storage tank. We elected to use the higher cost estimate of $9,000 for the pump assembly because we believe that many additive blenders would wish to have a double pump assembly to prevent their fueling arm from being shut down when maintenance must be performed on the primary pump. This also provides something of a conservatively high cost estimate. We also elected to use $3,000 as the estimated uninstalled cost of an injector unit for this same reason. This results in an total uninstalled cost of $16,000 for the equipment necessary to equip one injection loading arm: $13,000 for the tank and pump, and $3,000 for each injector.

We estimated the installed costs by two means. Our primary means was to apply the rule for such projects of multiplying the equipment costs by 2 to arrive at the installed cost and then by increasing this result by an additional 50 percent to ensure that the estimated cost would be sufficient to account for areas in the U.S. where labor costs are higher that the average (such as the Northeast). Since the Northeast/Mid-Atlantic Area was defined to exclude terminals in the Northeast from the marker requirement, this step might be expected to provide a conservatively high estimate of installation costs for those facilities that do need to install new injection equipment. Following this method results in an estimated installed cost of the equipment necessary to provide marker injection at one loading arm of $50,000 ($40,000 for the tank and pump assembly, and $10,000 for the injector assembly. Thus, for each additional loading arm at a terminal the cost would increase by $10,000. As a double check on these results we employed an in-house expert to estimate the time required of various skilled tradesmen at their respective hourly pay rates: e.g. instrumentation specialist, welder, welder's helper, concrete installer, engineer, and laborers. The estimate that we arrived at using this means supported the estimates described above. We believe that these estimates are more accurate than those provided by IFTOA, and therefore are using them to calculate the costs under this rule.

Terminal operators expressed concern regarding the potential burden of installing new additive injection equipment. In response to these comments, this rule includes provisions that exempt terminal operators from the fuel marker requirements in a geographic "Northeast/Mid-Atlantic Area" and Alaska.[TT] These provisions provide that any heating oil or 500 ppm sulfue L&M diesel fuel produced by a refiner or imported that is delivered to a retailer or wholesale-purchaser consumer inside the Northeast/Mid-Atlantic Area and Alaska does not need to contain the marker. The Northeast/Mid-Atlantic Area was defined to include the region where the majority of heating oil in the country is projected to continue to be supplied though the bulk distribution system (the Northeast and Mid-Atlantic). The vast majority of heating oil consumption in the U.S. will be within the Northeast/Mid-Atlantic Area. Outside of the

[TT]Small refiner and credit high sulfur NRLM will not be permitted to be sold in the area where terminals are not required to add the fuel marker to heating oil and 500 ppm sulfur L&M diesel fuel produced by refiners or imported (the "Northeast/Mid-Atlantic Area"). See Section IV.D. of the preamble. See Section 5.5.1.4 regarding our determination of the boundary of the Northeast/Mid-Atlantic Area to minimize the number of facilities that would need in to install new injection equipment for the fuel marker and to limit the volume of fuel that will need to be marked.

Northeast/Mid-Atlantic Area, we expect that only limited quantities of heating oil will be supplied, primarily from certain refiner's racks. Based on our analysis of the number of refineries that we expect will continue to produce heating oil and information from transmix processors on the number of such facilities, we estimate that 30 refineries and transmix processor facilities outside of the Northeast/Mid-Atlantic Area will distribute heating oil from their racks (in limited volumes) on a sufficiently frequent basis to warrant the installation of a marker injection system at a total one time cost of $1,500,000.

Terminals outside of the Northeast/Mid-Atlantic Area will mostly be located in areas without continued production and/or bulk shipment of heating oil. Consequently, any high sulfur diesel fuel they sell will typically be NRLM. Terminals located within the Northeast/Mid-Atlantic Area will not need to mark their heating oil, except for those few that choose to ship heating oil outside of the Northeast/Mid-Atlantic Area. The terminals most likely to install marker injection equipment will therefore be those in states outside the Northeast/Mid-Atlantic Area with modest markets for heating oil after the implementation of this program.

A few terminals inside the Northeast/Mid-Atlantic Area and near the border may choose to install marker injection equipment so that they can serve customers outside of the Northeast/Mid-Atlantic Area. However, based on our review of the proximity of terminals inside the Northeast/Mid-Atlantic Area to potential heating oil markets outside of the Northeast/Mid-Atlantic Area, we project that no more than 15 terminals will be induced to do so. Given the relatively low level of the potential demand for marked heating oil, we believe that the boundary area terminals that install marker injection equipment would provide for the loading of marked heating oil into trucks at only one loading bay (at $50,000 per terminal).

Some terminals outside of the Northeast/Mid-Atlantic Area that are supplied by the pipeline system which supplies the Northeast/Mid-Atlantic Area are likely to carry heating oil. Considering the relatively low volume of heating oil demand in the states in which these terminals are located, we estimate that only 15 terminals in this area will choose to install marker injection equipment so they can handle heating oil. We believe that such terminals would likely feel the need to have two loading bays at which marked heating oil could be delivered to a truck. Considering the added cost of a second injection station, the cost of new injection equipment would be $60,000 for each of these terminals. Except for heating oil distributed from these terminals, we project that the small quantities of fuel that are sold as heating oil outside of the Northeast/Mid-Atlantic Area will often meet a 500 ppm sulfur specification.[UU] Therefore, we expect that the other terminals outside of the Northeast/Mid-Atlantic Area will typically not need to distribute marked heating oil. For the infrequent instances in where terminals do receive >500 ppm fuel that they wish to distribute as heating oil (rather than blending it down to meet a 500 ppm standard using 15 ppm diesel fuel) we except that the terminal operator will elect to add the marker by hand, thereby avoiding the cost of installing new additive injection equipment. However, to provide a conservatively high estimated cost, we assumed that an additional 30

[UU] Fuel sold as heating oil outside of the Northeast/Mid-Atlantic Area will primarily be generated as a by-product of the distribution of 15 ppm diesel fuel by pipeline.

terminals outside of the Northeast/Mid-Atlantic Area will install new equipment to allow the injection of fuel marker at one truck loading bay (at $50,000 per terminal).

In analyzing the various situations as discussed above, we project that fewer than 60 terminals nationwide will choose to install injection equipment to add the marker to heating oil at a total cost of $4,150,000. The total capital cost to refiners and terminals to install injection equipment to add the marker to heating oil is estimated to be $5,650,000. Thus, the Northeast/Mid-Atlantic Area provisions in this rule minimize the number of terminals that will need to install additive injection equipment and its associated cost to comply with the fuel marker requirements.

Because heating oil is being marked to prevent its use in NRLM engines, for the purposes of estimating the impact of the marker requirement on the cost of the NRLM program we have spread the cost of adding the marker to heating oil over NRLM diesel fuel. Amortizing the capital costs of marker injection equipment over 20 years, results in an estimated cost of just 0.006 cents per gallon of affected NRLM diesel fuel supplied. Spreading the cost of the marker for heating oil over the volume of affected NRLM fuel results in an estimated cost of 0.003 cents per gallon of affected NRLM fuel. Adding the amortized cost of the injection equipment and the cost or the marker results in a total estimated cost of the marker requirement for heating oil in this rule of 0.01 cents per gallon of affected NRLM fuel.

In addition to heating oil, 500 ppm L&M fuel produced at refineries must also be marked from 2010 to 2012. As discussed in Section 7.2.2, we project that 6 refineries will produce this fuel. These refineries will have to install equipment to mark the fuel, unless they already have the equipment to mark heating oil. We assume that all 6 refineries will have to install new equipment. We do not expect that 500 ppm L&M fuel will be distributed by common carrier pipeline. Thus, it can be marked at the refinery and shipped to the final user by rail, truck or barge already marked. Therefore, we expect that very few terminals will add marking equipment exclusively for this fuel. To cover the few terminals that could do so, we have increased the number of new marking installations to 15. At $60,000, the total capital cost is $900,000. The cost of the marker is 0.03 cent per gallon of marked fuel. As described in Appendix 8B, we estimate that 2.975 billion gallons of 500 ppm L&M fuel will be produced in 2011. Thus, the cost of marking two years of 500 ppm L&M fuel production will be $1.875 million. Amortizing the $900,000 capital cost over 2 years of 15 and 500 ppm NRLM fuel production at 7 percent before taxes and adding in the marker costs yields a cost of 0.01 cents per gallon of NRLM fuel over this two year period for the marker requirement for L&M diesel fuel.

EIA FOKS/AEO Nonroad Fuel Volume Scenario:

Since using EIA nonroad fuel volumes rather than our primary fuel volume scenario (which utilized the EPA NONROAD model for nonroad fuel consumption) does not affect our assessment of product distribution patterns, our projections of the number of facilities that will need to install new injection equipment is the same under both scenarios. However, there are two factors that do have the potential to affect our per gallon cost estimate. The heating oil volume under the EIA nonroad volume scenario is greater than that under our primary volume scenario and the NRLM volume is smaller than under our primary volume scenario. The greater volume of heating oil under the EIA volume scenario means that it is likely that the volume of heating oil marked would be larger relative to our primary scenario, and the volume of NRLM to which this cost (and the capitol cost of the injection equipment) would be attributed would be smaller. Both of these criteria directionally increase the per gallon marker costs under the EIA volume scenario relative to our primary volume scenario. Because of these changes, the cost of adding the marker increases to 0.02 cent per gallon of affected NRLM diesel fuel supplied. The cost of marking L&M fuel stays at 0.01 cent per gallon from 2010-2012.

7.4.5 Distribution and Marker Costs Under Alternative Sulfur Control Options

EIA FOKS/AEO Nonroad Fuel Volume Scenario:

The distribution and marker costs assuming a reduced volume of nonroad fuel demand, resulting from deriving this demand from information in EIA's FOKS and AEO 2003 reports are summarized in Table 7.4-6 below. The derivation of each cost component was discussed in the previous sub-sections of Section 7.4.

TABLE 7.4-6
DISTRIBUTION COSTS FOR EIA FOKS/AEO FUEL DEMAND SCENARIO (CENTS PER GALLON) *

Cause of Increase in Distribution Costs	Time Period Over Which Costs Apply		
	2007-2010	2010-2014	After 2014
New Product Segregation as Bulk Plants	0.1	0.1	0.1
Distribution of Additional NRLM Volume to Compensate for Reduction in Volumetric Energy Content	0.08	0.1	0.1
Distillate Interface Handling	0	0.4	0.6
Heating Oil and L&M Fuel Marker	0.03	0.03	0.03
Total	0.2	0.6	0.8

* Costs have been rounded to one significant figure.

Other Fuel Control Options: The other fuel control options analyzed in this Final RIA are: 1) 500 ppm NRLM cap in 2007 with no subsequent control to 15 ppm, and 2) the proposed fuel program of 500 ppm NRLM in 2007 and 15 ppm nonroad fuel in 2010. The distribution costs for the 500 ppm NRLM only program are the same as those for the final NRLM fuel program in 2007.

Under the proposed fuel program, the distribution costs are essentially the same as those for the final rule when the costs are spread over all NRLM fuel. However, when the costs of distributing downgraded distillate are assigned to the only 15 ppm nonroad cap, as this is the incremental step in fuel control which causes these costs, the cost per gallon is of higher. In this case, the cost from 2010-2014 and in 2014 and beyond increase to 0.54 and 1.0 cent per gallon, respectively. In this case, the cost assigned to L&M fuel of distributing downgraded distillate is zero.

7.5 Total Cost of Supplying NRLM Fuel Under the Two-Step Program

The estimated refining, additive, and distribution costs from Sections 7.2 - 7.4 for the final NRLM fuel program and the other fuel control options considered are summarized in Table 7.5-1. Estimated costs during the various phases of these programs are also shown. Note that these fuel costs include the impacts of the small-refiner provisions. Also, in the case of the final NRLM fuel program, we spread the downgrade distribution costs across all NRLM fuel from 2010-2012, even though L&M fuel is still at 500 ppm. We did so to avoid a higher apparent cost of 15 ppm nonroad fuel from 2010-2012 than from 2012-2014. However, in the case of the proposed NRLM fuel program, we assigned all of the downgrade distribution cost to nonroad fuel, since the long term standard for L&M fuel is 500 ppm in this scenario. These cost estimates do not include the costs associated with testing, labeling, reporting, and recordkeeping to satisfy the compliance assurance provisions of the final rule, but these costs are small enought such that they would not change the values in Table 7.5-1 due to round-off.

Table 7.5-1
Summary of Fuel Costs for NRLM Fuel Control Options (cents per gallon, $2002)

Option	Specification	Year	Refining Costs (c/gal)	Distribution & Additive Costs (c/gal)	Total Costs (c/gal)
Final Rule	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm NRLM	2010-12	2.7	0.6	3.3
	500 ppm NRLM	2012-14	2.9	0.6	3.5
	15 ppm Nonroad	2010-12	5.0	0.8	5.8
	15 ppm NRLM	2012-14	5.6	0.8	6.4
	15 ppm NRLM	2014+	5.8	1.2	7.0
Proposed NRLM Program: 500 ppm NRLM in 2007, 15 ppm Nonroad in 2010	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm L & M	2010-14	2.7	0.2	2.9
	500 ppm L & M	2014+	2.7	0.2	2.9
	15 ppm Nonroad	2010-14	5.0	1.0	6.0
	15 ppm Nonroad	2014+	5.2	1.4	6.6
500 ppm NRLM in 2007 only (no 15 ppm fuel control)	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm NRLM	2010+	2.0	0.2	2.2
Final Rule with NRLM Volume Derived from EIA FOKS/AEO Reports	500 ppm NRLM	2007-10	1.9	0.2	2.1
	500 ppm NRLM	2010-12	2.8	0.6	3.4
	500 ppm NRLM	2012-14	3.0	0.6	3.6
	15 ppm Nonroad	2010-12	5.0	0.8	5.8
	15 ppm NRLM	2012-14	5.6	0.8	6.4
	15 ppm NRLM	2014+	5.7	1.2	6.9

Our projected total cost for supplying 500 ppm fuel is slightly less than the historical price differential between 500 ppm highway diesel fuel and uncontrolled high-sulfur diesel fuel. This differential has averaged about 2.5 cents per gallon for the five-year period from 1995 to 1999. Market prices may be either higher or lower than the societal costs estimated here as discussed in the next section. Thus, such comparisons can only be considered approximate. The primary reason that our projected costs for 500 ppm NRLM fuel might be lower than those for highway fuel is the ability to use existing hydrotreaters which are no longer being used to produce 500 ppm highway fuel in the 2007-2010 timeframe.

7.6 Potential Fuel Price Impacts

Transportation fuel prices are dependent on a wide range of factors, such as world crude oil prices, economic activity at the national level, seasonal demand fluctuations, refinery capacity utilization levels, processing costs (including fuel-quality specifications), and the cost of alternative energy sources (e.g., coal, natural gas). Only a few of these factors, namely fuel processing costs and refinery capacity utilization, may be affected by the NRLM fuel program.

Fuel processing and distribution costs will clearly be affected due to the cost of desulfurizing NRLM diesel fuel to either the 500 or 15 ppm sulfur cap. Refinery utilization levels may be affected as the capacity to produce 500 ppm or 15 ppm NRLM diesel fuel will depend on refiners' investment in desulfurization capacity. The potential impact of increased fuel processing and distribution costs on the prices is assessed below. The impact of the NRLM fuel program on refinery utilization levels is beyond the scope of this analysis. In the long run, refiners will clearly invest to produce adequate volumes of NRLM diesel fuels, as well as other distillate fuels. In the shorter term, the issue of refiners' adequate investment in desulfurization capacity is addressed in Section 5.9.

Two approaches to projecting future price impacts are evaluated here. The most direct approach to estimating the impact of the NRLM fuel program on prices is to observe the price premiums commanded by similar products in the marketplace. This is feasible for 500 ppm NRLM diesel fuel, as both 500 ppm highway diesel fuel and high-sulfur diesel fuel are both marketed today. As discussed in Section 7.2.2 above, the historical price premium of 500 ppm highway diesel fuel is 2.5 cents per gallon over that of high-sulfur distillate. As this premium is almost identical to our projected average total cost of the supplying 500 ppm NRLM diesel fuel, it represents one reasonable estimate of the future price impact of the 500 ppm NRLM diesel fuel standard.

It is not possible to use this methodology to project the price impact of the 15 ppm nonroad diesel fuel cap. Only a very limited amount of diesel fuel meeting a 15 ppm sulfur cap is currently marketed in the United States. This fuel is designed to be used in vehicle fleets retrofitted with particulate traps. The fuel is produced in very limited quantities using equipment designed to meet the current EPA and California highway diesel fuel standards. It is also much more costly to distribute due to its extremely low volume. Thus, the current market prices for 15 ppm diesel fuel in the United States are not at all representative of what might be expected in 2010 and 2012 under the NRLM program.

A greater volume, though still not large quantities, of 10 ppm sulfur diesel fuel is currently being sold in Europe. The great majority of this fuel is Swedish Class 1 (so-called City) diesel fuel, which is effectively a number one diesel fuel with very low aromatic content. The low aromatic specification significantly affects the cost of producing this fuel. Also, this fuel is generally produced using equipment not originally designed to produce 10 to 15 ppm sulfur fuel. Thus, as in the United States, the prices paid for this fuel are not representative of what will occur in the United States in 2010 and 2012. We therefore did not attempt to use current fuels, which have sulfur levels similar to the standards in this final rule, to evaluate our cost estimate for meeting the 15 ppm standard.

The other approach to project potential price impacts utilizes the projected costs to meet the 500 ppm and 15 ppm NRLM fuel sulfur caps. Both sulfur caps will affect fuel processing and distribution costs across the nation. (The exception will be California, where we presume that sulfur caps at least as stringent as those in this final rule will already be in effect.) However, these costs appear to vary significantly from region to region. Because of the cost of fuel distribution and limited pipeline capacities (pipelines are the most efficient means of transporting fuel), the NRLM fuel markets (and those for other transportation fuels) are actually regional in nature. Price differences can and usually do exist between the various regions of the country. Because of this, we have performed our assessment of potential price impacts on a regional basis. For the regions in our analysis, we have chosen PADDs. Practically speaking, there are probably more than five fuel markets in the United States with distinct prices. However, analyzing five distinct refining regions appears to provide a reasonable range of price impacts without adding precision that significantly exceeds our ability to project costs.

We made one exception to the PADD structure. PADD 3 (the Gulf Coast) supplies more high-sulfur distillate to PADD 1, particularly the Northeast, than is produced by PADD 1 refineries. Two large pipelines connect PADD 3 refineries to the Northeast, the Colonial and the Plantation. Because of this low-cost transportation connection, prices between the two PADDs are closely linked. We therefore combined our price analysis for PADDs 1 and 3.

As mentioned above, it is very difficult to predict fuel prices, either in the short term or long term. Over the past three years, transportation fuel prices (before excise taxes) have varied by a factor of two. Therefore, we have avoided any attempt to project absolute fuel prices. Because of the wide swings in absolute fuel prices, it is very difficult to assess the impact of individual factors on fuel price. The one exception is the price of crude oil, for two reasons. One, the cost of crude oil is the dominant factor in the overall cost of producing transportation fuels. Two, the pricing of almost all crude oils is tied to the "world" market price of crude oil. While the cost of producing crude oil in each region of the world is independent of those of other crude oil, contract prices are tied to crude oils traded on the open market, such as West Texas Intermediate and North Sea Brent crude oils. Thus, as the price of world crude oil climbs, the price of gasoline and diesel fuel climb across the United States, and vice versa. There is also a very rough correlation between refinery capacity utilization levels and fuel price. However, an unusually high availability of imports can cause prices to be relatively low despite high refinery capacity utilization rates in the United States.

For example, fuel prices, as a function of crude oil price, have varied widely over the past decade. Refiner records supplied to EIA indicate that refiners' net refining margin has ranged from a low of $0.45 per barrel in 1992 to a high of 2.78 per barrel in 2001.[59] Thus, fuel prices have varied between being so low that refineries are barely covering their cash expenses to high enough to justify moderate cost increases in refining capacity (but not new refineries). The NRLM program will very unlikely have a major impact on factors such as these. Thus, projecting the likely price impact of the NRLM program is highly speculative. The best that can be done is to develop a wide range of potential price impacts indicative of the types of conditions that have existed in the past.

In order to do this, we developed three projections for the potential impact of the NRLM program on fuel prices. The lower end of the range assumes a very competitive NRLM fuel market with excess refining capacity. In this case, fuel prices within a PADD are generally low and reflect only incremental operating costs. Consistent with this assumption, we project that the price of NRLM diesel fuel within a PADD will increase by the operating cost of the refinery with the highest operating cost in that PADD. This assumes that the refinery facing the highest operating cost in producing NRLM diesel fuel is setting the price of NRLM diesel fuel before this rule. This may or may not be the case. If not, the price increase may be even lower than that projected below. Under this "low -cost" set of assumptions, the refiner with the highest operating cost will not recover any of his invested capital related to desulfurizing NRLM diesel fuel, but all other refiners will recover some of their investment.[VV] Note that this scenario is only viable in the short run, since refineries need to recover both operating and fixed costs in the long run.

The mid-range estimate of price impacts can be termed the "full-cost" scenario. It assumes that prices within a PADD increase by the average refining and distribution cost within that PADD, including full recovery of capital (at the societal rate of return of 7 percent per annum before taxes). This scenario represents a case where there is full cost pass through to consumers under a competitive market setting. It should be noted that there are instances when this full-cost scenario produces lower costs than the maximum operating cost scenario. This occurs when the bulk of the low sulfur fuel can be produced at a relatively low cost compared to a few refineries facing relatively high operating costs.

Under this full-cost price scenario, lower cost refiners will recover their capital investment plus economic profit, while those with higher than average costs will recover some of their invested capital, but not all of it (i.e., at a rate of return lower than 7 percent annually).

The high-end estimate of price impacts assumes a NRLM fuel market that is constrained with respect to fuel production capacity. Prices rise to the point necessary to encourage additional desulfurization capacity. Also, prices are assumed to remain at this level in the long term, meaning that any additional desulfurization capacity barely fulfills demand and does not create

[VV] Theoretically, some refiners might recover all their invested capital if their operating costs were sufficiently lower than those of the high cost refiner. However, practically, in the case of desulfurizing NRLM diesel fuel, this is highly unlikely.

an excess in capacity that would tend to reduce prices. However, prices should not increase beyond this level in the long run, as this would encourage the construction of additional desulfurization capacity, lowering prices. Consistent with this, prices within a PADD increase by the maximum total refining and distribution cost of any refinery within that PADD, including full recovery of capital (at 7 percent per annum before taxes). All other refiners will recover more than their capital investment.

Table 7.6-1 presents the refining costs for the four phases of the NRLM fuel program under the three potential price scenarios.

Table 7.6-1
NRLM Fuel Refining Costs by Region (cents per gallon)

	Maximum Operating Cost	Average Total Cost	Maximum Total Cost
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2007-2010)			
PADDs 1 and 3	2.7	1.6	4.3
PADD 2	2.8	2.8	3.6
PADD 4	3.5	3.3	5.9
PADD 5	1.0	1.3	1.3
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2010-2012)			
PADDs 1 and 3	2.3	3.7	5.0
PADD 2	2.9	2.9	3.8
PADD 4	3.9	8.9	8.9
PADD 5	1.6	2.8	2.9
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2012-2014)			
PADDs 1 and 3	2.7	2.5	5.9
PADD 2	2.7	3.7	5.7
PADD 4	3.9	9.0	9.0
PADD 5	2.2	3.5	4.2
15 ppm Sulfur Cap: NRLM Fuel (2010-2012			
PADDs 1 and 3	4.7	4.6	8.5
PADD 2	5.0	7.1	8.5
PADD 4	7.1	11.6	12.7
PADD 5	3.6	4.3	4.3
15 ppm Sulfur Cap: NRLM Fuel (2012-2014)			
PADDs 1 and 3	4.8	4.8	8.6
PADD 2	6.4	7.8	10.0
PADD 4	7.0	11.7	12.7
PADD 5	3.6	4.3	4.3
15 ppm Sulfur Cap: NRLM Fuel (fully implemented program: 2014 +)			
PADDs 1 and 3	6.5	5.1	8.6
PADD 2	6.4	7.8	10.0
PADD 4	7.0	11.8	12.7
PADD 5	3.9	5.6	6.0

Table 7.6-2 shows these same cost projections including distribution and lubricity additive costs. The wholesale price of high-sulfur distillate fuel has varied widely even over the past twelve months. The March 2003 heating oil futures price alone has ranged from 60-110 cents per gallon since early 2002. Assuming a base cost of NRLM fuel of one dollar per gallon, the increase in NRLM fuel prices will be equivalent to the price increase in terms of cents per gallon shown below.

Table 7.6-2
Range of Possible Total Diesel Fuel Price Increases (cents per gallon)[a]

	Maximum Operating Cost	Average Total Cost	Maximum Total Cost
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2007-2010)			
PADDs 1 and 3	2.9	1.8	4.5
PADD 2	3.0	2.5	3.8
PADD 4	3.7	3.5	6.1
PADD 5	1.2	1.5	1.5
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2010-2012)			
PADDs 1 and 3	2.9	4.3	5.6
PADD 2	3.5	3.5	4.4
PADD 4	4.5	9.5	9.5
PADD 5	2.2	3.4	3.5
500 ppm Sulfur Cap: Nonroad, Locomotive and Marine Diesel Fuel (2012-2014)			
PADDs 1 and 3	3.3	3.1	6.5
PADD 2	3.3	4.3	6.3
PADD 4	4.5	9.6	9.6
PADD 5	2.8	4.1	4.8
15 ppm Sulfur Cap: NRLM Fuel (2010-2012			
PADDs 1 and 3	5.5	5.4	9.3
PADD 2	5.8	6.8	9.3
PADD 4	7.9	12.4	13.5
PADD 5	4.4	5.1	5.1
15 ppm Sulfur Cap: NRLM Fuel (2012-2014)			
PADDs 1 and 3	5.6	5.6	9.4
PADD 2	7.2	8.5	10.8
PADD 4	7.8	12.5	13.5
PADD 5	4.4	5.1	5.1
15 ppm Sulfur Cap: NRLM Fuel (fully implemented program: 2014 +)			
PADDs 1 and 3	7.7	6.3	9.8
PADD 2	7.6	7.9	11.2
PADD 4	8.2	13.0	13.9
PADD 5	5.1	6.8	7.2

Notes: [a] At a wholesale price of approximately $1.00 per gallon, these values also represent the percentage increase in diesel fuel price.

There are a number of assumptions inherent in these price projections. First, both the lower and upper limits of the projected price impacts described above assume that the refinery facing the highest compliance costs is currently the price setter in their market. If this is not the case, the price impacts would be lower than those shown in the previous tables. Many factors affect a refinery's total costs of fuel production. Most of these factors, such as crude oil cost, labor costs, age of equipment, etc., are not considered in projecting the incremental costs associated with lower NRLM diesel fuel sulfur levels. Thus, current prices may very well be set in any specific market by a refinery facing lower incremental compliance costs than other refineries. This point was highlighted in a study by the National Economic Research Associates (NERA) for AAM of the potential price impacts of EPA's 2007 highway diesel fuel program.[WW] In that study, NERA criticized the above referenced study performed by Charles River Associates, *et. al.* for API, which projected that prices will increase nationwide to reflect the total cost faced by the U.S. refinery with the maximum total compliance cost of all the refineries in the U.S. producing highway diesel fuel. To reflect the potential that the refinery with the highest projected compliance costs under the maximum price scenario is not the current price setter, we included the mid-point price impacts above. It is possible that even the lower limit price impacts are too high, if the conditions exist where prices are set based on operating costs alone. However, these price impacts are sufficiently low that considering even lower price impacts was not considered critical to estimating the potential economic impact of this rule.

Second, we assumed in some cases that a single refinery's costs could affect fuel prices throughout an entire PADD. While this is a definite improvement over analyses which assume that a single refinery's costs could affect fuel prices throughout the entire nation, it is still conservative, since one refinery's fuel can rarely have such a widespread influence. For example, Chicago and Detroit have experienced unusually high gasoline prices at times over the past 4 years, but prices in St. Louis, Cincinnati, Minneapolis, etc. were not similarly affected. High cost refineries are more likely to have a more limited geographical impact on market pricing than an entire PADD. In many cases, high cost refiners are able to operate profitably because they are in a niche location where transportation costs limit competition.

Third, by focusing solely on the cost of desulfurizing NRLM diesel fuel, we assume that the production of NRLM diesel fuel is independent of the production of other refining products, such as gasoline, jet fuel and highway diesel fuel. However, this is clearly not the case. Refiners have some flexibility to increase the production of one product without significantly affecting the others, but this flexibility is quite limited. It is possible that the relative economics of producing other products could influence a refiner's decision to increase or decrease the production of NRLM diesel fuel under the fuel program in this rule. It is this price response that causes fuel supply to match fuel demand. And, this response in turn could increase or decrease the price impact relative to those projected above.

[WW] "Potential Impacts of Environmental Regulations on Diesel Fuel Prices," NERA, for AAM, December 2000.

Fourth, all three of the above price projections are based on the projected cost for U.S. refineries of meeting the NRLM fuel sulfur caps. Thus, these price projections assume that imports of NRLM fuel, which are currently significant in the Northeast, are available at roughly the same cost as those for U.S. refineries in PADDs 1 and 3. We have not performed any analysis of the cost of lower sulfur caps on diesel fuel produced by foreign refiners. However, there are reasons to believe that imports of 500 and 15 ppm NRLM diesel fuel will be available at prices in the ranges of those projected for U.S. refiners.

One recent study analyzed the relative cost of lower sulfur caps for Asian refiners relative to those in the U.S., Europe and Japan.[XX] It concluded that costs for Asian refiners will be comparatively higher, due to the lack of current hydrotreating capacity at Asian refineries. This conclusion is certainly valid when evaluating lower sulfur levels for highway diesel fuels which are already at low levels in the U.S., Europe and Japan and for which refineries in these areas have already invested in hydrotreating capacity. It appears to be less valid when assessing the relative cost of meeting lower sulfur standards for NRLM fuels and heating oils which are currently at much higher sulfur levels in the U.S., Europe and Japan. All refineries face additional investments to remove sulfur from these fuels and so face roughly comparable control costs on a per gallon basis.

One factor arguing for competitively priced imports is the fact that refinery utilization rates are currently higher in the U.S. and Europe than in the rest of the world. The primary issue is whether overseas refiners will invest to meet tight sulfur standards for U.S., European and Japanese markets. Many overseas refiners will not invest, instead focusing on local, higher sulfur markets. However, many overseas refiners focus on exports. Both Europe and the U.S. are moving towards highway and nonroad diesel fuel sulfur caps in the 10-15 ppm range. Europe is currently and projected to continue to need to import large volumes of highway diesel fuel. Thus, it seems reasonable to expect that a number of overseas refiners will invest in the capacity to produce some or all of their diesel fuel at these levels. Many overseas refiners also have the flexibility to produce 10-15 ppm diesel fuel from their cleanest blendstocks, as most of their available markets have less stringent sulfur standards. Thus, there are reasons to believe that some capacity to produce 10-15 ppm diesel fuel will be available overseas at competitive prices. If these refineries were operating well below capacity, they might be willing to supply complying product at prices which only reflect incremental operating costs. This could hold prices down in areas where importing fuel is economical. However, it is unlikely that these refiners could supply sufficient volumes to hold prices down nationwide. Despite this expectation, to be conservative, in the refining cost analysis conducted earlier in this chapter, we assumed no imports of 500 ppm or 15 ppm NRLM diesel fuel. All 500 ppm and 15 ppm NRLM fuel was produced by domestic refineries. This raised the average and maximum costs of 500 ppm and 15 ppm NRLM diesel fuel and increased the potential price impacts projected above beyond what would have been projected had we projected that 5-10 percent of NRLM diesel fuel will be imported at competitive prices.

[XX] "Cost of Diesel Fuel Desulfurization In Asian Refineries," Estrada International Ltd., for the Asian Development Bank, December 17, 2002.

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