Chapter V: Economic Impact

A. Impact of Tier 2 Standards on Vehicle Costs

This section presents a detailed analysis of the vehicle-related costs we estimate would be incurred by manufacturers and consumers as a result of the Tier 2 standards. Section B. of this Chapter presents cost estimates for fuels changes. For manufacturers, the economic impact of the Tier 2 standards would include incremental costs for various vehicle hardware components, as well as up-front costs for research and development (R&D), certification, and facilities upgrades. Impacts on consumers would include increases in vehicle purchase price and changes in vehicle operating costs. Finally, this section provides estimates of the annual nationwide aggregate costs for Tier 2 vehicles.

1. Manufacturer Costs for Tier 2 Vehicles

a. Methodology

This section A.1. discusses EPA's estimates of costs to manufacturers for Tier 2 vehicles, including both hardware and developmental costs. Cost estimates have been prepared for all categories of vehicles, LDVs through LDT4. The cost estimates for medium-duty passenger vehicles (MDPVs) to meet Tier 2 exhaust and evaporative standards have been grouped with the costs for LDT4s.[1]   We have taken this approach with MDPVs because they are grouped with HLDTs in the program for phase-in purposes and are required to meet essentially the same requirements as vehicles in the LDT4 category. The estimates are based on projections of technology changes we consider most likely to be used by manufacturers to comply with the Tier 2 standards. To estimate costs, we have analyzed two sets of technologies for each vehicle class and engine type, a baseline technology package and a Tier 2 technology package. We used as a baseline, projected NLEV technologies for LDVs, LDT1s, and LDT2s, and Tier 1 technologies for LDT3s and LDT4s. These are the standards that vehicles will be meeting in 2003.[2] We have estimated the baseline technology packages based primarily on California Air Resources Board technology analyses done in support of the California LEV program,[1] with adjustments based on

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[1] EPA has categorized passenger vehicles (primarily SUVs and passenger vans) between 8,500 pounds and 10,000 pounds GVWR as MDPVs and has included them in the Tier 2 program.

[2] Even though the NLEV program ends in the Tier 2 time frame, we have not included the NLEV program in our Tier 2 analysis, since we have analyzed and adopted NLEV previously.   The MDPVs are required to meet engine-based standards prior to 2004. The projected technologies likely to be used by manufacturers to meet the 2003 engine-based standards form the baseline for these vehicles.

discussions with manufacturers about trends in technology.

As described in detail below, we have projected costs for the final Tier 2 standards. We have not projected specific incremental costs for the interim standards contained in the Tier 2 program.[3] To account for the interim standards in the cost analysis, we have assumed that the manufacturers would opt to accelerate the phase-in of Tier 2 vehicles rather than redesign vehicles for the interim program. The Tier 2 program averaging flexibility allows manufacturers to take this approach. We believe this approach by the manufacturers is likely because it allows manufacturers to avoid significant R&D efforts to meet standards that are in effect for only a few model years.

The following analysis projects a relatively uniform emission control strategy for various LDV, LDT, and MDPV models. However, this should not suggest that a single combination of technologies would be used by all manufacturers. Selecting technology packages requires extensive engineering development work and EPA does not know future technology mixes and costs with certainty for each vehicle model. New technological developments could significantly change the approach manufacturers would take to meet the standards. In addition, there are several emissions control technologies and several manufacturers of each. The Technological Feasibility portion of this RIA details many of the available technologies. Each manufacturer will choose the mix of technologies best suited for their vehicles. Manufacturers would have as many as eight years for R&D for some vehicles due to the phase-in schedule. We expect a large R&D effort involving extensive systems optimization to find the most cost effective mix of technologies for particular vehicle lines.

Nevertheless, we believe that the projections presented here provide a cost estimate representative of the different approaches manufacturers may ultimately take. Clearly, there are key technologies that manufacturers will likely use to meet the standards in most cases. We expect Tier 2 standards would be met through refinements of current emissions control components and systems rather than through the widespread use of new technologies. Current certification levels are well below current standards, also suggesting this approach makes sense. We have made a best estimate of the combination of technologies that any manufacturer might use to meet the standards at an acceptable cost and these technologies form the basis of the cost estimates. In making our cost estimates, we have relied on our own technology assessment including the results of our in-house testing, described in Chapter IV. Since California, in their LEV II program, has adopted essentially the same standards and time-line as Tier 2, we used California's technology and cost analyses as a source of information.[2] We also had several conversations with equipment and vehicle manufacturers whose input we also used for these

[3] We have assumed for purposes of our cost analysis that manufacturers will choose the Tier 2 program option that brings all 2004 model year vehicles into the Tier 2 program. We believe manufacturers are very likely to select this option due to the program flexibility it provides.

analyses. Most manufacturer input is considered confidential business information and therefore is not described in detail.

As noted above, we have not specifically analyzed smaller incremental changes in technologies which might occur due to interim standards between the baseline and the Tier 2 standards. For LDVs and LDT1s, the interim standards are a continuation of NLEV and therefore are equivalent to the baseline standards. For LDT2s, given the state of technology on current vehicles, we expect only minor changes in response to the interim standards. Many engine families are already certified at levels meeting the interim standards. In addition, broad averaging would be available which manufacturers could use in the early years of the phase-in when significant numbers of LDVs and LDT1s are also in the averaging program for the interim standards.

In 2006, when LDT2s may make up the large majority of vehicles remaining in the interim program manufacturers could use credits from model years 2004/2005 to comply with the interim standards. If this is not an option, we expect manufacturers could make a few minor modifications which would result in needed reductions. Most likely, the standards could be met through calibration changes which entail changes to software. These changes would not involve hardware or tooling changes. The R&D costs associated with these changes are already included in the relatively large R&D costs included for the program as a whole. In addition there are likely to be incremental improvements in the standard catalyst system for these vehicles due to progress made by catalyst manufacturers. These incremental improvements in washcoat technology are part of the normal progression of technology and would not likely result in an increase in the catalyst cost due to the competitiveness of the catalyst industry.

For LDT3s and LDT4s, there is a phase in to an interim fleet average NOx standard of 0.20 g/mile with an accompanying NMHC average of about 0.156 g/mile or less. Vehicles have their emissions capped at 0.60 g/mile NOx and 0.23 g/mile NMHC prior to phase-in.[4] Most engine families currently meet the caps. EPA expects that manufacturers could apply calibration changes and incremental catalyst improvements, as noted above for LDT2s, where necessary to ensure compliance with the caps. In addition, much of the R&D will have already taken place due to the California program which includes the same standards (MDV2 standards) for pre-2004 model year LDT3s. We do not expect these changes to result in increases to the cost of the program.

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[4] Manufacturers may select an option that provides an NMOG standard of 0.280 g/mile for LDT4s and MDPVs for the 0.6 g/mile NOx bin. Manufacturers also may select an option that allows MDPVs to be placed in a bin with a NOx level of 0.9 g/mile and a NMOG level of 0.280 g/mile during the interim program. Further, the optional program provides that diesel vehicles in the MDPV category may be certified to heavy-duty engine-based standards prior to 2008. The optional standards are equivalent to those that apply in the California LEV I program in 2004-2006.

For the interim fleet average NOx standard, (average standard of 0.2 g/mile NOx with an NMHC standard of about 0.156 g/mile or less), the approaches noted above may not be adequate in some cases. For vehicles well above the standard, manufacturers could redesign the vehicles to meet the interim standards. However, we believe it is more likely that manufacturers would phase these vehicles into the interim standards later in the phase-in period and use the program averaging flexibility to meet the interim standard. Therefore, rather than project a cost for vehicles to meet the interim standards, we have projected sales of Tier 2 vehicles prior to 2008 to average with and off-set those exceeding the interim standards. In other words, manufacturers would introduce Tier 2 vehicles early and use the averaging program to avoid redesigning vehicles to the interim standards. We believe this approach is reasonable considering manufacturers are likely to avoid significant R&D efforts to meet an interim standard that is in effect for only a few model years. Essentially, a few such interim vehicle models would have to be immediately redesigned to meet Tier 2 levels. Due to timing considerations, manufacturers are more likely to focus their resources on meeting the Tier 2 standards.

Vehicle phase-in estimates are needed to project annual aggregate costs during the phase-in period. We have projected an accelerated phase-in of LDT3s and LDT4s, as noted above. For both phase-in periods (for LDVs, LDT1s, LDT2s, and for LDT3s, LDT4s, and MDPVs), EPA has modeled that manufacturers will start the phase-in of Tier 2 standards with lighter vehicles and work their way to heavier vehicles until all vehicles up through LDT4s/MDPVs meet the Tier 2 standard in 2009. The phase-in projections described in further detail in section A.3., below.

Costs to the manufacturer are broken into variable costs (for hardware and assembly time) and fixed costs (for R&D, retooling, and certification). EPA projected costs separately for LDVs, the different LDT classes, and for different engine sizes (4, 6, 8 and 10-cylinder) within each class. Cost estimates based on the projected technology packages represent expected incremental variable and fixed costs for vehicles in the near-term, or during the first years of implementation.. For the long term, we have identified factors that would cause cost impacts to decrease over time. The analysis incorporates the expectation that manufacturers and suppliers will apply ongoing research and manufacturing innovation to making emission controls more effective and less costly over time. Also, we project that fixed costs would be recovered over the first five years of production, after which these costs would be recovered. These factors are discussed in further detail below.

b. Hardware Costs for Exhaust Emissions Control

The following section briefly describes each of the technologies EPA has included in the cost analysis and their costs incremental to the baseline use of the technology. Tables V-1 through V-5 at the end of this section provide the complete detailed projection of hardware changes and costs for each vehicle and engine type. A breakdown of the hardware costs for the evaporative system follow in section A.1.c. The Technological Feasibility portion of this RIA provides further detail on the technologies included in the cost analysis, as well as others that are less likely to be used to meet Tier 2 standards. The costs presented in this section are near-term costs, during the first few years of production. Long-term hardware costs are discussed in a following section.

Manufacturers are likely to use a systems approach to meeting the Tier 2 standards and much of the effort will be in optimizing how the various components and subsystems (engine, catalyst, fuel system, etc.) interact to achieve peak emissions performance. Some of these items are included as part of the technology discussions below. However, there are no hardware costs associated with these changes. The costs of optimization and calibration are part of a significant R&D effort EPA anticipates will be necessary to meet the Tier 2 standards.

i. Catalytic Converter System

The catalytic converter system is central to meeting current standards and improvements to the systems will be critical in meeting Tier 2 emissions standards. EPA projects that all Tier 2 LDVs, LDTs, and MDPVs will be equipped with advanced catalysts. Catalyst manufacturers are currently working with engine manufacturers on improved catalyst systems. To determine the cost increases due to improved catalyst systems, we first analyzed current Tier 1 and NLEV systems for the baseline and then projected what changes may be necessary to meet Tier 2 standards.

EPA first determined an average catalyst system for the baseline vehicles. Catalyst systems vary in size and configuration due to factors such as engine size and emissions levels, vehicle packaging constraints, cost, and manufacturer preference. Catalyst systems typically consist of single or dual units (main or underfloor catalysts) and may also include one or two smaller catalysts placed close to the engine (close coupled). For the baseline, we examined the total volume, precious metal loading, and architecture of the main, or underfloor catalysts to derive an average baseline catalyst for the various vehicle types and engine sizes. We also noted whether or not vehicles were also equipped with additional close coupled catalysts.

After establishing baseline catalyst systems, we then projected changes to the catalyst system for the Tier 2 analysis. In general, manufacturers could meet the standards by using very large catalysts with relatively high precious metal loading. Many of the test programs that have been conducted to demonstrate the feasibility of very low standards have featured vehicles with such catalyst systems. However, based on uniform input from catalyst manufacturers, this is not the approach we expect manufacturers to take in meeting the Tier 2 standards. Catalyst manufacturers anticipate that improvements to the catalyst systems design, structure, and formulation will also play a critical role in reducing emissions. These improvements are aimed at decreasing emissions while minimizing the increase in catalyst volume and precious metal loading. Manufacturers are working on these catalyst systems today.

We do expect some increase in average catalyst size (volume) and precious metal loading. We believe that it is reasonable to expect catalyst systems to be sized such that the underfloor catalyst volume will be equal to engine displacement and that loading will increase by about 10 percent. Perhaps of equal importance will be the R&D efforts on the vehicle manufacturers part to optimize engine performance and control systems so that the catalyst can function at peak efficiency. Additional information on catalyst test programs and catalyst changes is available in the Technical Feasibility Section of this RIA.

For the main or underfloor catalysts, EPA projects that improvements to the catalyst architecture and formulation will increase catalyst costs by $2.44 to $6.59, depending on the vehicle and engine type. These improvements include double layer washcoats and increasing the cell density of the catalyst substrate to 600 cells per inch (cpi). We estimate that increases in the catalyst volume and precious metal loading will account for the largest portion of the catalyst cost increase due to the high cost of precious metals. We anticipate the change in catalyst volume to cost between $12.20 and $67.10 per vehicle. We derived the increased volume cost by taking the baseline cost of the catalyst per liter ($61/liter) and multiplying by the increase in catalyst volume.[5] Larger catalyst volume increases are projected for 6-cylinder engines in LDT applications than for 8-cylinder engines due to relatively low baseline catalyst volumes for 6-cylinder engines. We projected an increase in precious metal loading, in addition to the increased volume, at a total per vehicle cost from $2.36 for light-duty vehicles to $29.50 for LDTs and MDPVs with the largest displacement engines. The details of the underfloor catalyst cost estimates are provided in Table V -1.

[5] We have updated the baseline per liter catalyst cost and other catalyst costs from the NPRM to reflect changes in the spot prices of precious metals. The precious metals costs used in the cost analysis are shown in Table V-1.

Table V-1. Main or Underfloor Catalyst Cost Breakdown

Vehicle Type	Engine Type	Sales wtd. Engine Displacement (liter)	Projected Baseline Cat. Volume (liter)	Projected Tier 2 Cat. Volume (liter)	Increased Volume Cost (a) (dollars)	Increased Platinum (Pt) (grams)	Increased Palladium (Pd) (grams)	Increased Rhodium (b) (Rh) (grams)	Added Pt cost (dollars)	Added Pd cost (dollars)	Added Rh cost (b) (dollars)	Higher substrate cost (e) (dollars)	Total Increased Cost (dollars)
LDV	4-cylinder	2.0	1.8	2.0	12.20	0.000	0.000	0.085	0	0	2.35	2.44	16.99
	6-cylinder	3.2	2.8	3.2	24.40	0.000	0.000	0.138	0	0	3.86	3.90	32.16
	8-cylinder	4.5	4.0	4.5	30.50	0.000	0.000	0.194	0	0	5.43	5.49	41.42
LDT/	4-cylinder	2.3	2.3	2.3	0.00	0.000	0.000	0.097	0	0	2.71	2.81	5.52
MDPV	6-cylinder	3.7	2.6	3.7	67.10	0.035	0.540	0.157	0.44	7.17	4.39	4.52	83.62
	8-cylinder	5.4	4.7	5.4	42.70	0.082	0.550	0.229	1.03	7.30	6.41	6.59	64.03
	8/10-cylinder	6.0	4.7	5.4	42.70	0.164	1.100	0.458	2.06	14.62	12.82	6.59	78.79

Precious Metal Costs

	$/troy ounce	$/gram
Pt	412	12.58
Pd	390	13.29
Rh	868	28.00

(a) Baseline catalyst cost is $61/liter. Increased catalyst volume costs are the increase in catalyst volume multiplied by $61/liter.
(b) Increase in Rh of 1.2 g/cu ft

Close coupled catalysts are typically small relative to the main catalysts, under one-half liter in volume. Their small size is due to packaging constraints associated with their location close to the engine and their purpose, to warm-up quickly and reduce cold-start emissions. They also typically have relatively high precious metal loading. Due to these factors, EPA is not projecting changes to the close coupled catalysts, only changes in their usage. For NLEV vehicles (LDV, LDT1 and LDT2), the percentage of baseline vehicles equipped with close coupled catalysts is high, between 60 and 100 percent, depending on the vehicle and engine type. We believe that the use of close coupled catalysts has likely peaked in these classes and we have not projected increases in usage for Tier 2. For LDT3s, LDT4s, and MDPVs the use of close coupled catalysts is currently low relative to the other classes, especially for MDPVs. For Tier 2 LDT3s, LDT4s and MDPVs, we have projected the use of close coupled catalysts to increase to be equivalent to the other vehicle categories. The cost of dual close coupled catalysts are projected to be between $107.54 and $131.44, for six and eight liter engines, respectively.

ii. Improved Fuel Control and Delivery

Precise fuel metering is critical to keeping the catalyst at peak operating efficiency. Much of the effort for improved fuel control is in calibration and system optimization. For some vehicles, EPA has included costs for hardware changes including improved exhaust gas oxygen sensors and air-assisted fuel injection. There are two types of improved oxygen sensors available for use in Tier 2 vehicles, universal exhaust gas oxygen sensors (UEGO) and fast light-off or planar sensors. UEGO sensors are the most expensive type of sensor and offer the most precise fuel control. We believe manufacturers will opt for planar sensors, which offer a key advantage of quick warm-up, allowing for precise fuel control sooner during cold starts. Many baseline vehicles also will likely be equipped with planar sensors. The incremental cost of planar sensors is estimated to be four dollars per sensor. We expect that the improved sensors would be used only before the catalyst in the exhaust system for fuel control, with conventional heated exhaust gas oxygen sensors used post catalyst for catalyst monitoring and additional fuel control.

Air assisted fuel injection is used to provide a better air fuel mixture to the engine, which can be especially critical during engine warm-up. The technology can offer other advantages in terms of engine performance which also makes it an attractive technology. For air assisted fuel injection, the injectors must be redesigned to include a new adapter. We have projected that 50 percent of Tier 2 vehicles will be equipped with air assisted fuel injection at a cost of two dollars for each improved injector.

As indicated above, much of the improvements in fuel control are likely to be accomplished through system calibration. As such, they include software upgrade costs, rather than hardware costs. EPA has included such costs in the R&D cost. These improvements may include individual cylinder fuel control and adaptive learning.

iii. Secondary Air Injection

Manufacturers sometimes use a rich air/fuel mix during cold start to improve engine performance and driveability. Secondary injection of air into exhaust ports after cold start when the engine is operating rich can be used to promote combustion of unburned HC and CO which results from the rich air/fuel mix. Air injection can also be used in conjunction with spark retard to provide additional heat to the catalyst for quicker catalyst warm-up. EPA projects increased use of electric-powered air injection strategies for Tier 2 vehicles equipped with 6- and 8-cylinder engines. The air injection systems consist of an electric-powered air pump with integrated filter and relay, wiring, an air shut-off valve with integrated solenoid, a check valve, tubing, and brackets. We estimate the system cost to be 50 and 65 dollars for six- and eight-cylinder engines, respectively.

iv. Exhaust System Improvements

Manufacturers can insulate the exhaust system so the exhaust heat does not escape, but is instead maintained within the system to promote catalyst warm-up. Improved materials include laminated thin-walled exhaust pipes and double walled low thermal capacity manifolds (the two walls have a small air gap between them that acts as an insulator). EPA estimates that improved exhaust pipe costs one dollar per foot, with total system costs of between one and six dollars, depending on engine size. Low thermal capacity manifolds are estimated to cost 20 to 40 dollars depending on engine size. In some cases, manufacturers may be able to use the combined exhaust system improvements in lieu of adding close-coupled catalysts. However, we are not projecting an increase in the use of low thermal capacity manifolds due to the Tier 2 standards. For most vehicles, manufacturers using close-coupled catalysts are not likely to need the improved manifolds as well.

In addition, exhaust systems can be made leak-free which improves fuel control and catalyst efficiency. As noted in the previous section, precise fuel control is critical to catalyst performance and the oxygen sensor is a key element of fuel control. Air leaking into the exhaust system can influence the oxygen sensor causing an improper fuel adjustment. Also, additional air in the exhaust stream can lead to an oxidizing environment in the catalyst, diminishing the catalyst's ability to reduce NOx. Leak-free systems include corrosion-free flexible couplings, corrosion-free steel, and improved welding of catalyst assemblies. We estimate that many baseline vehicles and all Tier 2 vehicles will be equipped with leak-free exhaust systems at an incremental cost of 10 to 20 dollars depending on engine size.

v. Engine Combustion Chamber Improvements

Manufacturers may make a number of improvements to their engines as they are redesigned, including adding a second spark plug to each cylinder, adding a swirl control valve to improve mixing of air and fuel, or other changes needed to improve cold start combustion. Engine changes are not likely to be uniform throughout the industry. EPA believes that significant engine improvements for LDVs, LDT1s and LDT2s are likely to have been made as part of the effort to meet NLEV standards. The Tier 2 standards are not likely to drive a second set of major changes to these engines. Therefore, EPA has not included an engine modification cost for these vehicles. For LDT3s, LDT4s and MDPVs, which would be changing from Tier 1 to Tier 2 technology, we have included a hardware cost for engine modifications of $10 and $15 for six and eight/ten cylinder engines, respectively.

vi. Exhaust Gas Recirculation (EGR)

One of the most effective means of reducing engine-out NOx emissions is exhaust gas recirculation. By recirculating spent exhaust gases into the combustion chamber, the overall air-fuel mixture is diluted, lowering peak combustion temperatures and reducing NOx. Many EGR systems in today's vehicles utilize a control valve that requires vacuum from the intake manifold to regulate EGR flow. Some vehicles are being equipped with electronic EGR in place of mechanical back-pressure designs. By using electronic solenoids to open and close the EGR valve, the flow of EGR can be more precisely controlled. EPA projects that the use of full electronic EGR systems will increase due to Tier 2 standards. We estimate that about 50 percent of Tier 2 vehicles will be equipped with electronic EGR at an incremental cost of ten dollars per vehicle.

vii. Total Hardware Costs for Exhaust Emissions Control

Table V-2 provides a summary of the total hardware costs for each vehicle and engine type. Tables V-3 through V-7 present detailed estimated manufacturer costs itemized for each vehicle and engine type. The tables indicate EPA's estimate of the percentage of use of the technologies for both the baseline and the Tier 2 vehicles. Some of the technologies listed, such as individual cylinder fuel control and retarded spark timing, involve calibration changes only and have no hardware costs associated with them.

Table V-2. Total Estimated Per Vehicle Manufacturer Incremental Hardware Costs for the Tier 2 Standards

	LDV ($)	*LDT1 ($)*	*LDT2 ($)*	*LDT3 ($)*	*LDT4/MDPV ($)*
4-cylinder	24.99	13.16	8.16	N/A	N/A
6-cylinder	65.16	91.46	90.98	238.86	N/A
8-cylinder	75.42	N/A	70.97	171.99	171.99
larger 8/10-cylinder*	N/A	N/A	N/A	N/A	291.54
sales weighted	44.69	39.87	84.27	178.74	187.53

* Primarily used in MDPVs.

Table V-3. Estimated Incremental Manufacturer Hardware Cost for Tier 2 LDV Compared to NLEV LDV

	4-Cylinder (53%)				6-Cylinder (39%)				8-Cylinder (8%)			
Emission Control Technology	Tech. cost est. (in dollars)	% of NLEV vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)	Tech. cost est. (in dollars)	% of NLEV vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)	Tech. cost est. (in dollars)	% of NLEV vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)
Universal Exhaust Gas Oxygen Sensor (UEGO)	10.00	0	0	0.00	20.00	0	0	0.00	20.00	0	0	0.00
Air-assisted fuel injection (a)	8.00	50	50	0.00	12.00	50	50	0.00	16.00	50	50	0.00
Individual cylinder fuel control (b)	0.00	0	10	0.00	0.00	10	10	0.00	0.00	10	10	0.00
Retarded spark timing at start-up (b)	0.00	100	100	0.00	0.00	100	100	0.00	0.00	100	100	0.00
Improved precision fuel control (c)	0.00	100	100	0.00	0.00	100	100	0.00	0.00	100	100	0.00
Faster microprocessor	3.00	0	100	3.00	3.00	0	100	3.00	3.00	0	100	3.00
Fast light-off exhaust gas oxygen sensor (planar)	4.00	100	100	0.00	8.00	100	100	0.00	8.00	100	100	0.00
Heat optimized exhaust pipe (d)		0	0	0.00		0	0	0.00		0	0	0.00
Leak-free exhaust system (e)	10.00	100	100	0.00	20.00	100	100	0.00	20.00	100	100	0.00
Engine modifications (f)	0.00	0	0	0.00	10.00	100	100	0.00	15.00	100	100	0.00
Full electronic EGR	10.00	0	50	5.00	10.00	0	50	5.00	10.00	0	50	5.00
Close-coupled catalyst	55.00	60	60	0.00	55.00	0	0	0.00	55.00	0	0	0.00
Underbody or main catalyst	80.00	70	70	0.00	80.00	100	100	0.00	80.00	60	60	0.00
Dual close-coupled catalyst		0	0	0.00	90.00	100	100	0.00	110.00	80	80	0.00
Dual underbody or main catalyst		0	0	0.00	160.00	0	0	0.00	160.00	40	40	0.00
Increased catalyst volume	12.20	0	100	12.20	24.40	0	100	24.40	30.50	0	100	30.50
Increased catalyst loading (Rh)	2.35	0	100	2.35	3.86	0	100	3.86	5.43	0	100	5.43
Improved double layer washcoat + 600 cpsi cell density	2.44	0	100	2.44	3.90	0	100	3.90	5.49	0	100	5.49
Secondary air injection (g)	50.00	0	0	0.00	50.00	0	50	25.00	65.00	10	50	26.00
Total Incremental Cost				24.99				65.16				75.42

(a) Air assisted fuel injection requires minor redesign of the idle air control valve at no additional cost and addition of an adapter to each injector at a cost of $2 each.

(b) Improved precision fuel control envisioned here and retarded spark-timing at start-up constitute software changes only, at no additional hardware cost.

(c) Improved precision fuel control constitute software changes only, at no additional hardware cost.

(d) Length of heat optimized exhaust pipe required is estimated to be one foot for 4-cylinder engines, four feet for 6-cylinder engines, and six feet for 8-cylinder engines, at a cost of $1 per foot incremental.

(e) Leak-free exhaust system includes corrosion free flexible coupling, plus improved welding of catalyst assemblies.

(f) Types of engine modifications may be less uniform throughout the industry and may include items such as an additional spark plug per cylinder, addition of a swirl control valve or other hardware needed to achieve cold combustion stability, improved fuel economy

(g) Cost of air injection includes an electric-powered air pump with integrated filter and relay, wiring, air-shut-off valve with integral solenoid, check valve, tubing and brackets.

Table V-4. Estimated Incremental Manufacturer Hardware Cost for Tier 2 LDT1 Compared to NLEV LDT1

	4-Cylinder (65.9%)				6-Cylinder (34.1%)			
Emission Control Technology	Tech. cost est. (in dollars)	% of NLEV vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)	Tech. cost est. (in dollars)	% of NLEV vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)
Universal Exhaust Gas Oxygen Sensor (UEGO)	10.00	0	0	0.00	20.00	0	0	0.00
Air-assisted fuel injection (a)	8.00	50	50	0.00	12.00	50	50	0.00
Individual cylinder fuel control (b)	0.00	10	10	0.00	0.00	10	10	0.00
Retarded spark timing at start-up (b)	0.00	100	100	0.00	0.00	100	100	0.00
Improved precision fuel control (c)	0.00	100	100	0.00	0.00	100	100	0.00
Faster microprocessor	3.00	0	100	3.00	3.00	0	100	3.00
Fast light-off exhaust gas oxygen sensor (planar)	4.00	100	100	0.00	8.00	100	100	0.00
Heat optimized exhaust pipe (d)	1.00	0	0	0.00	4.00	0	0	0.00
Leak-free exhaust system (e)	10.00	100	100	0.00	20.00	100	100	0.00
Engine modifications (f)	0.00	0	0	0.00	10.00	100	100	0.00
Full electronic EGR	10.00	0	50	5.00	10.00	0	50	5.00
Close-coupled catalyst	55.00	60	60	0.00	55.00	0	0	0.00
Underbody or main catalyst	80.00	70	70	0.00	80.00	100	100	0.00
Dual close-coupled catalyst	0.00	0	0	0.00	90.00	100	100	0.00
Dual underbody or main catalyst	0.00	0	0	0.00	160.00	0	0	0.00
Increased catalyst volume	0.00	100	100	0.00	67.10	0	100	67.10
Increased catalyst loading	2.35	0	100	2.35	3.86	0	100	3.86
Improved double layer washcoat + 600 cpsi cell density	2.81	0	100	2.81	4.52	0	0	0.00
Secondary air injection (g)	50.00	50	50	0.00	50.00	50	75	12.50
Total Incremental Cost				13.16				91.46

(a) Air assisted fuel injection requires minor redesign of the idle air control valve at no additional cost and addition of an adapter to each injector at a cost of $2 each.

(b) Improved precision fuel control envisioned here and retarded spark-timing at start-up constitute software changes only, at no additional hardware cost.

(c) Improved precision fuel control constitute software changes only, at no additional hardware cost.

(d) Length of heat optimized exhaust pipe required is estimated to be one foot for 4-cylinder engines, four feet for 6-cylinder engines, at a cost of $1 per foot incremental.

(e) Leak-free exhaust system includes corrosion free flexible coupling, plus improved welding of catalyst assemblies.

(f) Types of engine modifications may be less uniform throughout the industry and may include items such as an additional spark plug per cylinder, addition of a swirl control valve or other hardware needed to achieve cold combustion stability, improved fuel economy

(g) Cost of air injection includes an electric-powered air pump with integrated filter and relay, wiring, air-shut-off valve with integral solenoid, check valve, tubing and brackets.

Table V-5. Estimated Incremental Manufacturer Hardware Cost for Tier 2 LDT2 Compared to NLEV LDT2

	4-Cylinder (2.3%)				6-Cylinder (73.7%)				8-Cylinder (24%)			
Emission Control Technology	Tech. cost est. (in dollars)	% of NLEV vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)	Tech. cost est. (in dollars)	% of NLEV vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)	Tech. cost est. (in dollars)	% of NLEV vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)
Universal Exhaust Gas Oxygen Sensor (UEGO)	10.00	0	0	0.00	20.00	0	0	0.00	20.00	0	0	0.00
Air-assisted fuel injection (a)	8.00	50	50	0.00	12.00	50	50	0.00	16.00	50	50	0.00
Individual cylinder fuel control (b)	0.00	10	10	0.00	0.00	10	10	0.00	0.00	10	10	0.00
Retarded spark timing at start-up (b)	0.00	100	100	0.00	0.00	100	100	0.00	0.00	100	100	0.00
Improved precision fuel control (c)	0.00	100	100	0.00	0.00	100	100	0.00	0.00	100	100	0.00
Faster microprocessor	3.00	0	100	3.00	3.00	0	100	3.00	3.00	100	100	0.00
Fast light-off exhaust gas oxygen sensor (planar)	4.00	100	100	0.00	8.00	100	100	0.00	8.00	100	100	0.00
Heat optimized exhaust pipe (d)	1.00	0	0	0.00	4.00	0	0	0.00	6.00	0	0	0.00
Low thermal capacity manifold	20.00	25	25	0.00	40.00	25	25	0.00	40.00	25	25	0.00
Leak-free exhaust system (e)	10.00	100	100	0.00	20.00	100	100	0.00	20.00	100	100	0.00
Engine modifications (f)	0.00	0	0	0.00	10.00	100	100	0.00	15.00	100	100	0.00
Full electronic EGR	10.00	50	50	0.00	10.00	50	50	0.00	10.00	50	50	0.00
Close-coupled catalyst	55.00	60	60	0.00	55.00	0	0	0.00	55.00	0	0	0.00
Underbody or main catalyst	80.00	70	70	0.00	80.00	100	100	0.00	80.00	60	60	0.00
Dual close-coupled catalyst		0	0	0.00	90.00	100	100	0.00	110.00	80	80	0.00
Dual underbody or main catalyst		0	0	0.00	160.00	0	0	0.00	160.00	40	40	0.00
Increased catalyst volume	0.00	0	0	0.00	67.10	0	100	67.10	42.70	0	100	42.70
Increased catalyst loading (Pt)	0.00	0	0	0.00	4.32	0	0	0.00	10.13	0	0	0.00
Increased catalyst loading (Pd)	0.00	0	0	0.00	51.67	0	0	0.00	52.83	0	0	0.00
Increased catalyst loading (Rh)	2.35	0	100	2.35	3.86	0	100	3.86	5.43	0	100	5.43
Improved double layer washcoat + 600 cpsi cell density	2.81	0	100	2.81	4.52	0	100	4.52	6.59	0	100	6.59
Secondary air injection (g)	50.00	0	0	0.00	50.00	50	75	12.50	65.00	50	75	16.25
Total Incremental Cost				8.16				90.98				70.97

(a) Air assisted fuel injection requires minor redesign of the idle air control valve at no additional cost and addition of an adapter to each injector at a cost of $2 each.

(b) Improved precision fuel control envisioned here and retarded spark-timing at start-up constitute software changes only, at no additional hardware cost.

(c) Improved precision fuel control constitute software changes only, at no additional hardware cost.

(d) Length of heat optimized exhaust pipe required is estimated to be one foot for 4-cylinder engines, four feet for 6-cylinder engines, and six feet for 8-cylinder engines, at a cost of $1 per foot incremental.

(e) Leak-free exhaust system includes corrosion free flexible coupling, plus improved welding of catalyst assemblies.

(f) Types of engine modifications may be less uniform throughout the industry and may include items such as an additional spark plug per cylinder, addition of a swirl control valve or other hardware needed to achieve cold combustion stability, improve fuel economy

(g) Cost of air injection includes an electric-powered air pump with integrated filter and relay, wiring, air-shut-off valve with integral solenoid, check valve, tubing and brackets.

Table V-6. Estimated Incremental Manufacturer Hardware Cost for Tier 2 LDT3 Compared to Current LDT3s

	6-Cylinder (10.1%)				8-Cylinder (89.9%)			
Emission Control Technology	Tech. cost est. (in dollars)	% of Tier 1 vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)	Tech. cost est. (in dollars)	% of Tier 1 vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)
Universal Exhaust Gas Oxygen Sensor (UEGO)	20.00	0	0	0.00	20.00	0	0	0.00
Air-assisted fuel injection (a)	12.00	0	50	6.00	16.00	0	50	8.00
Individual cylinder fuel control (b)	0.00	0	10	0.00	0.00	0	10	0.00
Retarded spark timing at start-up (b)	0.00	25	100	0.00	0.00	25	100	0.00
Improved precision fuel control (c)	0.00	50	100	0.00	0.00	50	100	0.00
Faster microprocessor	3.00	0	100	3.00	3.00	0	100	3.00
Fast light-off exhaust gas oxygen sensor (planar)	8.00	80	100	1.60	8.00	80	100	1.60
Heat optimized exhaust pipe (d)	4.00	0	0	0.00	6.00	0	0	0.00
Leak-free exhaust system (e)	20.00	50	100	10.00	20.00	50	100	10.00
Low thermal capacity manifold	40.00	25	25	0.00	40.00	25	25	0.00
Engine modifications (f)	10.00	0	100	10.00	15.00	0	100	15.00
Full electronic EGR	10.00	0	50	5.00	10.00	0	50	5.00
Close-coupled catalyst	55.00	0	0	0.00	55.00	0	0	0.00
Underbody or main catalyst	80.00	100	100	0.00	80.00	60	60	0.00
Dual close-coupled catalyst	107.54	12	100	94.64	131.44	55	80	32.86
Dual underbody or main catalyst	160.00	0	0	0.00	160.00	40	40	0.00
Increased catalyst volume	67.10	0	100	67.10	42.70	0	100	42.70
Increased catalyst loading (Pt)	0.44	0	100	0.44	1.03	0	100	1.03
Increased catalyst loading (Pd)	7.17	0	100	7.17	7.30	0	100	7.30
Increased catalyst loading (Rh)	4.39	0	100	4.39	6.41	0	100	6.41
Improved double layer washcoat + 600 cpsi cell density	4.52	0	100	4.52	6.59	0	100	6.59
Secondary air injection (g)	50.00	0	50	25.00	65.00	0	50	32.50
Total Incremental Cost				238.86				171.99

(a) Air assisted fuel injection requires minor redesign of the idle air control valve at no additional cost and addition of an adapter to each injector at a cost of $2 each.

(b) Improved precision fuel control envisioned here and retarded spark-timing at start-up constitute software changes only, at no additional hardware cost.

(c) Improved precision fuel control constitute software changes only, at no additional hardware cost.

(d) Length of heat optimized exhaust pipe required is estimated to be one foot for 4-cylinder engines, four feet for 6-cylinder engines, and six feet for 8-cylinder engines, at a cost of $1 per foot incremental.

(e) Leak-free exhaust system includes corrosion free flexible coupling, plus improved welding of catalyst assemblies.

(f) Types of engine modifications may be less uniform throughout the industry and may include items such as an additional spark plug per cylinder, addition of a swirl control valve or other hardware needed to achieve cold combustion stability, improved fuel economy

(g) Cost of air injection includes an electric-powered air pump with integrated filter and relay, wiring, air-shut-off valve with integral solenoid, check valve, tubing and brackets.

Table V-7. Estimated Incremental Manufacturer Hardware Cost for Tier 2 LDT4s and MDPVs Compared to Current Vehicles

	8-Cylinder (87%)				Larger 8 & 10-Cylinder (13%)			
Emission Control Technology	Tech. cost est. (in dollars)	% of Tier 1 vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)	Tech. cost est. (in dollars)	% of Tier 1 vehs. that use tech.	% Tier 2 that will req. tech.	Inc. cost over Tier 1 (in dollars)
Universal Exhaust Gas Oxygen Sensor (UEGO)	20.00	0	0	0.00	20.00	0	0	0.00
Air-assisted fuel injection (a)	16.00	0	50	8.00	16.00	0	50	8.00
Individual cylinder fuel control (b)	0.00	0	10	0.00	0.00	0	10	0.00
Retarded spark timing at start-up (b)	0.00	25	100	0.00	0.00	25	100	0.00
Improved precision fuel control (c)	0.00	50	100	0.00	0.00	50	100	0.00
Faster microprocessor	3.00	0	100	3.00	3.00	0	100	3.00
Fast light-off exhaust gas oxygen sensor (planar)	8.00	80	100	1.60	8.00	80	100	1.60
Heat optimized exhaust pipe (d)	6.00	0	0	0.00	6.00	0	0	0.00
Leak-free exhaust system (e)	20.00	50	100	10.00	20.00	50	100	10.00
Low thermal capacity manifold	40.00	25	25	0.00	40.00	25	25	0.00
Engine modifications (f)	15.00	0	100	15.00	15.00	0	100	15.00
Full electronic EGR	10.00	0	50	5.00	10.00	0	50	5.00
Close-coupled catalyst	55.00	0	0	0.00	55.00	0	0	0.00
Underbody or main catalyst	80.00	60	60	0.00	80.00	60	60	0.00
Dual close-coupled catalyst	131.44	55	80	32.86	131.44	0	80	105.15
Dual underbody or main catalyst	160.00	40	40	0.00	160.00	40	40	0.00
Increased catalyst volume	42.70	0	100	42.70	42.70	0	100	42.70
Increased catalyst loading (Pt)	1.03	0	100	1.03	2.06	0	100	2.06
Increased catalyst loading (Pd)	7.30	0	100	7.30	14.62	0	100	14.62
Increased catalyst loading (Rh)	6.41	0	100	6.41	12.82	0	100	12.82
Improved double layer washcoat + 600 cpsi cell density	6.59	0	100	6.59	6.59	0	100	6.59
Secondary air injection (g)	65.00	0	50	32.50	65.00	0	100	65.00
Total Incremental Cost				171.99				291.54

(a) Air assisted fuel injection requires minor redesign of the idle air control valve at no additional cost and addition of an adapter to each injector at a cost of $2 each.

(b) Improved precision fuel control envisioned here and retarded spark-timing at start-up constitute software changes only, at no additional hardware cost.

(c) Improved precision fuel control constitute software changes only, at no additional hardware cost.

(d) Length of heat optimized exhaust pipe required is estimated to be one foot for 4-cylinder engines, four feet for 6-cylinder engines, and six feet for 8-cylinder engines, at a cost of $1 per foot incremental.

(e) Leak-free exhaust system includes corrosion free flexible coupling, plus improved welding of catalyst assemblies.

(f) Types of engine modifications may be less uniform throughout the industry and may include items such as an additional spark plug per cylinder, addition of a swirl control valve or other hardware needed to achieve cold combustion stability, improved fuel economy

(g) Cost of air injection includes an electric-powered air pump with integrated filter and relay, wiring, air-shut-off valve with integral solenoid, check valve, tubing and brackets.

c. Hardware Costs for Evaporative Emissions Control

The standards for evaporative emissions are technologically feasible now. Many designs have been certified by a wide variety of manufacturers that already meet these standards. A review of the 1999 model year certification results indicates that the average family is certified at slightly less than 1.0 grams per test (gpt) on the three day diurnal plus hot soak test, i.e. at less than half the current 2.0 gpt standard. Many families are certified at levels considerably below 1.0 gpt, including a few families that are certified below 0.5 gpt.

The new standards will not require the development of new materials or even the new application of existing materials. Low permeability materials and low loss connections and seals are already used to varying degrees on current vehicles. The standards will likely ensure their consistent use and discourage switching to cheaper materials or designs to take advantage of the large safety margins manufacturers have under current standards ("backsliding").

Complex (and perhaps somewhat more expensive) approaches have been proposed which involve pressurized fuel systems or fuel bladders. Such systems have not been implemented in production, nor do we believe they are necessary for the standards we are finalizing. We believe manufacturers will follow more traditional paths in reducing their evaporative emissions.

There are two traditional approaches to reducing evaporative emissions. The first is to minimize the potential for permeation and leakage by reducing the number of hoses, fittings and connections. However, some joints and connections are necessary for vehicle assembly and service and no known joint has zero emissions.

The second traditional approach is to use less permeable hoses and lower loss fittings and connections. Low permeability hoses and seals as well as low loss fittings are currently available. Fluoropolymer materials can be added as liners to hose and component materials to yield large reductions in permeability over such conventional materials as monowall nylon. In addition, fluoropolymer materials can greatly reduce the impact of alcohols on hydrocarbon permeability of evaporative components, hoses and seals. Alcohols, present in about 10 percent of gasoline sold in the U.S., cause swelling of conventional materials which leads to increases in permeability and can also lead to tearing and leakage in situations where the materials are constrained in place, such as with gaskets and O-rings. Due to the common presence of alcohols such as ethanol in the gasoline pool and its adverse affect on materials and emissions durability, we believe material upgrades such as those discussed above are necessary to ensure that the benefits are captured in-use.

Steel fuel tanks and steel fuel lines have essentially zero losses due to permeation, but are vulnerable to leakage at joints and interfaces. Manufacturers are moving toward plastic fuel tanks for their lighter weight and greater ability to be molded to odd shapes. However, plastic tanks are permeable and are also susceptible to seepage and higher permeability at areas where connections and welds are made. Materials and manufacturing techniques exist to reduce these losses.

To estimate the per vehicle cost of an improved evaporative system, we looked at the incremental cost for an average current model year vehicle with a steel fuel tank (certified at ~ 1.0 g) to go from a certification level of 1.0 grams per test to a level of about 0.5 grams per test on the three day test cycle. The emission levels of 1.0 and 0.5 gpt were chosen because 1.0 represents the current average certification level and 0.5 gpt represents a certification target that leaves a compliance margin of about 100 percent between the certification level and the applicable standard (0.95 gpt for our LDV/LLDT standard). The reductions and costs of the individual items are shown in Table V-8 below, and reflect the incremental cost of moving to low permeability materials, improved designs or low loss connectors. The items in the chart are ranked in order of decreasing cost effectiveness. Since the evaporative test procedure measures evaporative emissions each day over a three day period and then uses the highest day, gram per day numbers in the table are a reasonable proxy for grams per test data.

Table V-8. Potential Evaporative Improvements and Their Costs to Manufacturers [3]
(grams per day)

Emission Source	*Baseline Vehicle (a)*	*Improved Vehicle (b)*	*Change (a-b)*	*Cost ($) (d)*	*Cost Effectiveness Ranking (d)/(a-b)*
Fuel cap seal	0.10	0.01	0.09	0.20	1
Fuel pump assembly seal	0.10	0.01	0.09	0.40	2
Fuel and vapor line	0.23	0.01	0.22	1.25	3
Fuel rail/manifold connectors	0.06	0.02	0.04	0.40	4
Canister improvements	0.12	0.04	0.08	1.00	5
Fill tube clamps	0.06	0.02	0.04	0.60	6
Fuel and vapor line connectors	0.18	0.06	0.12	2.20	7
Fill tube/fill neck connector	0.20	0.10	0.10	5.00	8
Allowance for non-fuel emissions	0.20	0.20	0	------	-------

Table V-8 shows that a manufacturer can choose from a range of improvements, and attain significant reductions in evaporative emissions. By selecting the first five items from the table, the manufacturer can achieve a reduction in evaporative emissions of about 0.5 g/day for a total cost of about three dollars per vehicle. The cost-effectiveness of these five items taken together is approximately $2,400 per ton of VOCs removed. While these figures were based on a passenger car, we believe it is reasonable to assume the same costs here for light duty trucks since the same basic components are used on trucks and cars. Non fuel emissions may be higher for larger vehicles, but our evaporative standard for HLDTs (1.2 gpt) and MDPVs (1.4 gpt) is higher to include a larger allowance for non-fuel losses.

Lastly, we note that most manufacturers are moving to “returnless” injection systems, and at least one major manufacturer’s current products are 100 percent returnless. Through more precise fuel pumping and metering, these systems eliminate the return line in the fuel injection system which carries unneeded fuel from the fuel injectors back to the fuel tank. Returned fuel is a significant source of fuel tank heat and vapor generation, and therefore of evaporative emissions. The elimination of return lines reduces the total length of hose on the vehicle and also reduces the number of fittings and connections which can leak. We believe that most vehicles will move to returnless injection systems either before or in conjunction with the phase-in of the Tier 2 standards.

Our analysis is conservative in that it did not include the impact of these returnless systems. We believe that changing to a returnless injection system may provide a 0.15 g/day evaporative emissions benefit. If the example vehicle described above were equipped with a returnless injection system, then, we would expect evaporative emissions of about 0.85 gpt. Such a vehicle would require a smaller emission reduction (0.35 gpt) to hit the certification target of 0.5 gpt.

Returnless vehicles have about one third less vapor and fuel line footage and proportionally fewer connections and joints, accounting for most of the reduction attributable to returnless systems. We would expect an emission improvement and cost about one third less than those shown in the table above for fuel and vapor lines and fuel and vapor line connectors. Because the emission improvement and cost change by the same fraction, we would not expect a change in the cost effectiveness or ranking of these items. While the 0.15 gpt is also due to small reductions in losses from all but the last item in the table above, we believe that, in the end, the cost effectiveness of the standards will not be significantly different for vehicles with return or returnless systems.

d. Assembly Costs

Another variable cost manufacturers may incur are increases in vehicle assembly costs. EPA has not estimated increased assembly costs for Tier 2 vehicles because the vast majority of changes to the vehicles are likely to be improvements to existing emissions control systems. Therefore, we believe that assembly cost increases are likely to be negligible. Assembly costs for components would be incurred by the component supplier and included in the component price estimates shown above.

e. Development and Capital Costs

In addition to the hardware costs described in the previous section, vehicle manufacturers would also incur developmental and capital costs due to the Tier 2 standards. These fixed costs include costs for research and development (R&D), tooling, and certification, which manufacturers incur prior to the production of the vehicles.

The Tier 2 standards would be phased-in over four model years beginning in 2004 for LDVs, LDT1s, and LDT2s and a two year period beginning in 2008 for LDT3s, LDT4s and MDPVs. This approach would provide lead-time for R&D for the various vehicle lines to proceed systematically. EPA estimates R&D costs of about $5 million per vehicle line (100,000 vehicles). R&D primarily includes engineering staff time and development vehicles. A large part of the research effort will be evaluating and selecting the appropriate mix of emission control components and optimizing those components into a system capable of meeting the Tier 2 standards. It also includes engine modifications where necessary and air/fuel ratio calibration. Manufacturers will take differing approaches in their research programs. We estimate that $5 million would cover about 25 engineering staff person years and about 20 development vehicles.[6] We have estimated this large R&D effort because calibration and system optimization is likely to be a critical part of the effort to meet Tier 2 standards. However, we believe that the R&D costs are likely overstated because the projection ignores the carryover of knowledge from the first vehicle lines designed to meet the standard to others phased-in later.

Tooling costs include facilities modifications necessary to produce and assemble components and vehicles meeting the new standards. EPA has included tooling costs due to the Tier 2 standards of approximately $2 million per vehicle line (100,000 vehicles). We believe that this is a reasonable estimate based on engineering judgement, after reviewing previous estimates of tooling costs for emissions control components.[4]

EPA recently conducted a detailed cost analysis of its vehicle certification program as part of the CAP 2000 rulemaking, which revised the certification program and is expected to significantly reduced manufacturer certification costs.[5] For CAP 2000, EPA estimated a total annual certification cost to the industry of between $40 and $65 million. Manufacturers incur a large portion of these costs annually as part of certification and compliance and would incur

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[6] This estimate is based on staff cost of $60 per hour and development vehicle cost of $100,000 per vehicle.

those costs without any change to the standards. However, EPA does allow manufacturers to carry-over some data generated for certification when vehicles are not significantly changed from one model year to the next. This test data is generated to demonstrate vehicle emissions levels and emissions durability. Due to the new standards, such data would have to be generated for the new Tier 2 vehicles, rather than carried over from previous model years. Therefore, we believe it is appropriate to include the cost of generating new emissions test and durability data as part of the cost analysis for Tier 2. Based on the CAP 2000 rule, EPA estimates the cost of this testing to be about $15 million industry-wide. This estimate does not account for the ability of manufacturers in some cases to carry-over certification data from California, which would lower certification costs.

We expect there to be a certification testing cost savings for HLDTs due to the change in test procedures for these vehicles. For Tier 2, HLDTs will be emissions tested at the same test weight as is required for the CAFE fuel economy test (i.e., loaded vehicle weight). Currently, HLDTs are emissions tested at a higher weight (adjusted loaded vehicle weight). This change in emissions test procedure will allow manufacturers to measure fuel economy and emissions during the same test, eliminating one of the FTP tests currently required. To be conservative, however, we have not reduced the certification cost estimate to reflect this likely cost savings.

EPA estimated that the R&D costs would be incurred on average three years prior to production and the tooling and certification costs would be incurred one year prior to production. These fixed costs were then increased by seven percent for each year prior to the start of production to reflect the time value of money. We estimated total R&D and tooling costs per vehicle class by multiplying the costs per vehicle line (100,000 vehicles) by sales estimates for each vehicle class divided by 100,000 vehicles. Finally, for the cost analysis, the fixed costs were recovered over the first five years of production at a rate of seven percent.

EPA estimates the average per vehicle fixed costs to be between $19 and $22, as shown in Table V-9 (aggregate costs are described in the following section). We derived the per vehicle fixed cost by dividing the total fixed cost per vehicle class over the five year recovery period by the estimated total sales per vehicle class over the same period. Differences in fixed costs among vehicle classes occur because we have projected a phase-in of Tier 2 LDVs and LDTs/MDPVs and changes in sales volumes over time for the vehicle classes. The aggregate fixed costs, vehicle phase-ins, and sales projections are described in section 3., below.

Table V-9. Per Vehicle Fixed Costs

	LDV ($)	*LDT1 ($)*	*LDT2 ($)*	*LDT3 ($)*	*LDT4/MDPV ($)*
R&D	16.10	14.23	14.08	14.34	15.48
Tooling	5.63	4.97	4.92	5.01	5.41
Certification	0.30	0.27	0.26	0.26	0.29
Total	22.03	19.47	19.26	19.61	21.18

f. Total Near-term and Long-term Manufacturer Costs

The previous section presented estimates of per vehicle variable and fixed costs to the manufacturer for the first few model years of production. These near-term per vehicle costs are shown in Table V-10. The costs in Table V-10 include the costs for the evaporative system.

Table V-10. Total Per Vehicle Manufacturer Costs - Near Term

	LDV ($)	*LDT1 ($)*	*LDT2 ($)*	*LDT3 ($)*	*LDT4/MDPV ($)*
Variable	47.94	43.12	87.52	181.99	190.78
Fixed	22.03	19.47	19.26	19.61	21.18
Total	69.97	62.59	106.78	201.60	211.96

For the long-term, there are factors that EPA believes are likely to reduce the costs to manufacturers. As noted above, we project fixed costs to be recovered by manufacturers during the first five years of production, after which they would expire. For variable costs, research in the costs of manufacturing has shown that as manufacturers gain experience in production, they are able to lower the per-unit cost of production. These effects are often described as the manufacturing learning curve.[6]

The learning curve is a well documented phenomenon dating back to the 1930s. The general concept is that unit costs decrease as cumulative production increases. Learning curves are often characterized in terms of a progress ratio, where each doubling of cumulative production leads to a reduction in unit cost to a percentage "p" of its former value (referred to as a "p cycle"). The organizational learning which brings about a reduction in total cost is caused by improvements in several areas. Areas involving direct labor and material are usually the source of the greatest savings. Examples include, but are not limited to, a reduction in the number or complexity of component parts, improved component production, improved assembly speed and processes, reduced error rates, and improved manufacturing process. These all result in higher overall production, less scrappage of materials and products, and better overall quality. As each successive p cycle takes longer to complete, production proficiency generally reaches a relatively stable plateau, beyond which increased production does not necessarily lead to markedly decreased costs.

Companies and industry sectors learn differently. In a 1984 publication, Dutton and Thomas reviewed the progress ratios for 108 manufactured items from 22 separate field studies representing a variety of products and services[7]. The distribution of these progress ratios is shown in Figure V-1. Except for one company that saw *increasing* costs as production continued, every study showed cost savings of at least five percent for every doubling of production volume. The average progress ratio for the whole data set falls between 81 and 82 percent. Other studies (Alchian 1963, Argote and Epple 1990, Benkard 1999) appear to support the commonly used p value of 80 percent, i.e., each doubling of cumulative production reduces the former cost level by 20 percent.

The learning curve is not the same in all industries. For example, the effect of the learning curve seems to be less in the chemical industry and the nuclear power industry where a

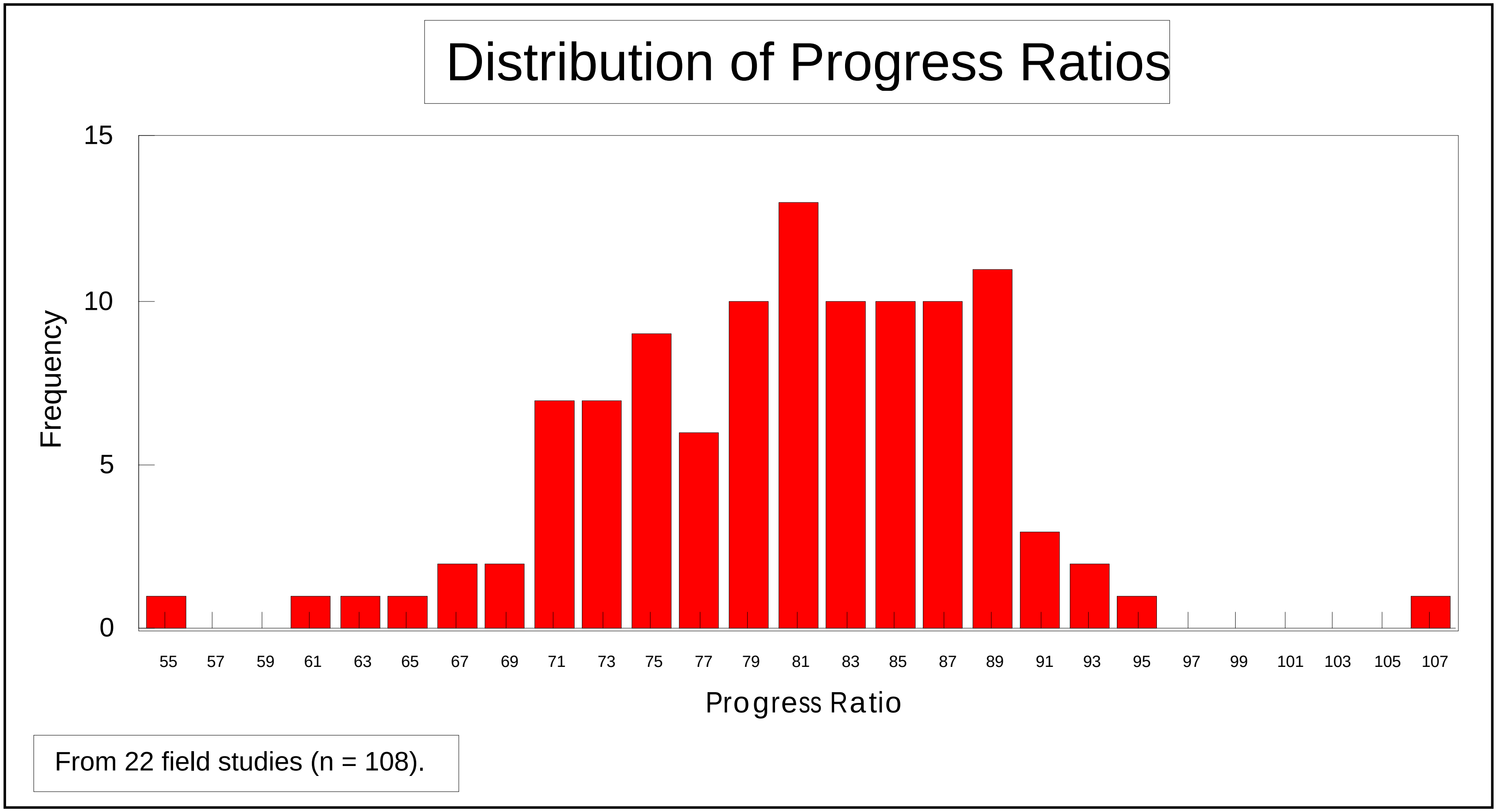

Figure V-1. Distribution of Progress Ratios
(Dutton and Thomas, 1984)

doubling of cumulative output is associated with 11% decrease in cost (Lieberman 1984, Zimmerman 1982). The effect of learning is more difficult to decipher in the computer chip industry (Gruber 1992).

We applied a p value of 80 percent in this analysis. Using one year as the base unit of production, the first doubling would occur at the start of the third model year of production. Beyond that time, we did not incorporate further cost reductions due to the learning curve. We applied the learning curve reduction only once because we anticipate that for the most part the Tier 2 standards would be met through improvements to existing technologies rather than through the use of new technologies. With existing technologies, there would be less opportunity for lowering production costs.

In addition, we did not apply the learning curve to the catalyst precious metal costs due to the uncertainty of future precious metal prices. Although manufacturers may be able to reduce the use of precious metals due to the learning curve, the future price of precious metals is highly uncertain. Any savings due to a reduction in the amount of precious metals used for a catalyst system could be overcome by increased precious metal unit costs. Finally, we did not apply the learning curve to the evaporative system costs. Evaporative systems have been well developed and the anticipated system improvements are available today and are likely to be employed by manufacturers prior to 2004 on a large number of vehicles.

Table V-11 presents EPA's estimates of long-term per vehicle manufacturer costs. As noted above, we have projected cost reductions due to the learning curve to occur in the third year of production and the fixed costs to expire for the sixth year of production. Due to the phase-in of standards, these cost reductions are not tied to particular model years. As shown in Table V-11, we project manufacturer costs to decrease by 21 to 40 percent for the long-term. The percentage decrease in costs varies largely due to the variation in projected costs for precious metals, which are not subject to the learning curve cost reduction factor. We have projected a larger increase in the use of precious metals for LDT3s, LDT4s, and MDPVs than for LDVs.

Table V-11. Long-term Total Incremental Per Vehicle Manufacturer Costs

Production Year	*LDV ($)*	*LDT1 ($)*	*LDT2 ($)*	*LDT3 ($)*	*LDT4/MDPV ($)*
1st and 2nd year	69.97	62.59	106.78	201.60	211.96
3rd year: learning curve applied	64.23	58.38	99.12	180.69	189.96
6th year: fixed costs expire	42.20	38.91	79.86	161.08	168.78

2. Tier 2 Vehicle Consumer Costs

Costs to consumers consists of increases in vehicle purchase price and increases in vehicle operating costs. EPA has not estimated an increase in vehicle operating costs due to the Tier 2 vehicle standards. Manufacturers will most likely meet the standards through improvements to existing technologies. The costs of fuel quality improvements are provided in section B, below.

We do not anticipate that the improvements to technologies will affect fuel economy or in-use maintenance. We expect the standards to be met through improvements in current technologies rather than through the use of new technologies. We do not believe these improvements would adversely affect fuel economy or maintenance costs. Also, we have not observed fuel economy losses in our testing programs described in Chapter IV.

For the up-front cost or purchase price increase, EPA anticipates that manufacturers would pass along their incremental costs for Tier 2 vehicles, including a markup for overhead and profit, to vehicle purchasers. Thus, we expect consumers would experience purchase price increases based on the manufacturer costs discussed in section A.1. To account for manufacturer overhead and profit, manufacturer incremental variable costs are multiplied be a Retail Price Equivalent (RPE) factor. The RPE factor we used in this analysis, 1.26, is the same one EPA has used in previous analyses for LDVs and LDTs. This methodology and the RPE mark-up factor are based on contractor studies regarding hardware costs and RPEs.[8,9] Table V-12 presents the increases in vehicle costs to consumers EPA has estimated for Tier 2 vehicles. The costs shown in Table V-12 include the costs of the evaporative system improvements (incremental to ORVR), as well as the improved exhaust emissions control system.[7] We expect decreases in manufacturing costs over time, described in section 1.f., above, to be passed along to consumers in the form of purchase price decreases.

Table V-12. Incremental Per Vehicle Costs to Consumers for Tier 2 Vehicles

Production Year	*LDV ($)*	*LDT1 ($)*	*LDT2 ($)*	*LDT3 ($)*	*LDT4/MDPV ($)*
1st and 2nd year	82.43	73.80	129.54	248.92	261.57
3rd year: learning curve applied	75.22	68.50	119.90	222.60	233.52
6th year: fixed costs expired	53.19	49.03	100.64	202.99	212.34

[7] EPA estimated costs to the manufacturer for evaporative system improvements to be $3.25. The RPE for the evaporative system would therefore be $4.10.

The above analysis presents estimated vehicle costs for Tier 2 exhaust and evaporative emissions standards. In addition, we are finalizing On-board Diagnostics (OBD II) and On-board Refueling Vapor Recovery (ORVR) for MDPVs. Light-duty vehicles and light-duty trucks already must comply with these requirements. The OBD II and ORVR requirements were proposed as part of a Heavy-duty Engines and Vehicles Regulation (64 FR 58472) and the detailed cost analyses are presented in the RIA for that rulemaking (Docket A-98-32, Item II-B-01)

In summary, for OBD II, the vehicles will likely be equipped with additional and improved hardware such as additional oxygen sensors, solenoids for the evaporative system purge and leak check, and improved electronic control modules. We estimate the total cost to consumers for the system to be about $80 per vehicle. For the ORVR system, we estimate the cost to consumers to be about $10 per vehicle. Also, the ORVR system provides a fuel economy savings of about $6 over the lifetime of the vehicle. This savings occurs because refueling vapors are captured, and burned in the engine, rather than escaping to the atmosphere.

3. Annual Total Nationwide Costs for Tier 2 Vehicles

a. Overview of Nationwide Vehicle Costs

The above analyses developed incremental per vehicle manufacturer and consumer cost estimates for each class of Tier 2 LDVs, LDTs, and MDPVs. With data for the current size and characteristics of the vehicle fleet and projections for the future, we have translated these per vehicle costs into estimated total annual costs to the nation for the Tier 2 standards. Table V-13 presents the results of this analysis. As shown in Table V-13, EPA projected total cost starting at $269 million in 2004 and peaking at $1,579 million in 2009 when the phase-in of the standards is complete. Per-vehicle costs savings over time reduce projected costs to a value of $1,351 million in 2014, after which the growth in vehicle population leads to increasing costs that reach $1,392 million in 2020. The calculated total costs represent a combined estimate of fixed costs, as they are allocated over fleet sales during the first five years of sale, and variable costs assessed at the point of sale. The aggregate costs include exhaust and improved evaporative control systems. These estimates do not include costs due to improved fuel quality, which are presented in section 2., below. The remainder of this section discusses the methodology we used to derive the total annual cost estimates and provides total annual vehicle costs for calender years 2004 through 2020.

Table V-13. Estimated Annual Nationwide Costs (thousands of dollars)

Category	*2004*	*2009*	*2014*	*2020*
LDV	253,327	358,521	301,938	311,110
LDT1	0	98,943	73,026	75,245
LDT2	0	579,898	499,791	514,973
LDT3	9,544	339,109	306,125	315,425
LDT4/MDPV*	5,907	201,991	169,841	174,000
Total	268,778	1,578,462	1,350,721	1,391,753

*Includes costs for OBD II and ORVR requirements for MDPVs

b. Methodology

To prepare these estimates, we projected sales for each vehicle class, the change in sales over time, and the phase-in of Tier 2 vehicles for each class over the phase-in schedule. We estimated current vehicle sales based on sales data submitted by vehicle manufacturers as part of certification. These sales estimates correlated reasonably well with other available sales information. We reduced the national sales numbers by 10 percent for LDVs and nine percent for LDTs to account for sales in California.[10] California sales were excluded from this analysis because California emissions standards apply to those vehicles.

To account for the current trend in sales of fewer LDVs and more LDTs, we reduced the LDV fraction of total sales and increased the LDT fraction of total sales by 1.6 percent per year from 1998 through 2008.[11] After 2008, sales were stabilized at a mix of 40 percent LDVs and 60 percent LDTs. We also applied this shift in sales in its analysis of emissions reductions. These projections are based on the current trend toward increased sales of LDTs. We are aware of an industry study that projects the sales split leveling off much sooner at half LDVs and half LDTs.[12] Using a higher percentage of LDT sales results in higher overall cost projections because the per vehicle costs are higher for LDTs. In this way, EPA's cost analysis is more conservative than if we assumed sales leveled off at one-half LDVs and one-half LDTs. Finally, we have modeled overall vehicle sales to grow at 0.5 percent per annum on average over the period of the analysis.[13] Table V-14 provides EPA's estimates for vehicle sales for 1998 and projections for select future years.

Table V-14. Estimated Annual 49-State Vehicle Sales (thousands of vehicles)

Category	*1998*	*2004*	*2008*	*2012*	*2020*
LDV	7,352	6,266	5,502	5,620	5,849
LDT1	1,012	1,268	1,447	1,475	1,535
LDT2	3,374	4,228	4,824	4,917	5,117
LDT3	1,025	1,284	1,465	1,493	1,554
LDT4/MDPV[8]	541	663	747	762	793
Total	13,304	13,709	13,985	14,267	14,848

In addition to vehicle sales, EPA also projected a phase-in of Tier 2 vehicles (including improved evaporative controls systems) for each vehicle class. Projecting the phase-in of Tier 2 vehicles is necessary to estimate aggregate costs of the standards during the phase-in period. Rather than assume a phase-in of 25/50/75/100 percent for each vehicle class, LDV, LDT1, and LDT2, we projected a phase-in based on cost and difficulty considerations. We projected that manufacturers would begin the phase-in with LDVs and end with LDT2s. We believe manufacturers will be able to meet Tier 2 standards more easily and at a lower cost for lighter vehicles compared to heavier vehicles.

We have projected some sales of Tier 2 LDT3s and LDT4s prior to 2008, for reasons described in section V.A.1.a. above. These early sales would off-set vehicles in higher bins in the averaging program for the interim standards. To make these projections, we assessed the current certification levels of LDT3s and LDT4s to determine how averaging could be used by manufacturers to avoid redesigning vehicles to meet interim standards. We found that, currently, about 29 percent of vehicles overall would fall into the highest bin (0.60 g/mile NOx), 28 percent in the next highest bin (0.3 g/mile NOx) and the remaining 43 percent would meet the interim standard (0.2 g/mile NOx). We conducted this analysis for each manufacturer and determined how many vehicles meeting the Tier 2 standards would be needed to off-set vehicles in the higher bins. In this analysis, the vehicles in the highest bin were phased-in last. This analysis may overestimate the number of Tier 2 vehicles necessary because it does not account for the manufacturers' ability to make minor adjustments to vehicles close to the interim standard (i.e., those in the 0.3 g/mile NOx bin) which may allow those vehicles to meet the interim standard.

[8] To account for sales of MDPVs, we estimated 1998 sales of 70,000 vehicles and projected growth at a rate of one-half percent per year. The MDPV sales projections were added to the yearly sales estimates for LDT4s.

Essentially, these analyses have resulted in projections of Tier 2 vehicle phase-ins which start with the lighter vehicles within each of the two categories and progress through the heavier vehicles until all vehicles meet the Tier 2 standards in 2009. Table V-15 presents EPA's projected phase-in of Tier 2 vehicles we modeled for the aggregate cost analysis over the phase-in period of 2004 through 2008. Manufacturers would select the appropriate phase-in for their vehicle fleets. These modeling projections simply allow EPA to perform the aggregate cost analysis, reasonably accounting for the standards phase-in and the manufacturer's ability to average within the various programs.

Table V-15. Projected Overall Industry Phase-in of Tier 2 Vehicles and Improved Evaporative Emissions Controls For Purposes of the Aggregate Cost Analysis

Model Year	*LDV (%)*	*LDT1 (%)*	*LDT2 (%)*	*LDT3* (%)*	*LDT4/MDPV* (%)*
2004	50	0	0	3	0
2005	100	0	0	9	0
2006	100	100	30	26	0
2007	100	100	100	68	0
2008	100	100	100	100	35
2009	100	100	100	100	100

*Improved evaporative systems have been projected to phase-in 50 percent in 2008 and 100 percent in 2009 for LDT3s, LDT4s,and MDPVs starting with LDT3s in 2008. OBD II is required for MDPVs starting in 2004. The phase-in for ORVR for MDPVs is 40/80/100 percent in 2004-2006.

This is the phase-in schedule for Tier 2 vehicles EPA used in this analysis based on the assumption that manufacturers would perceive a fleet-wide integrated average strategy as the most efficient and least-cost approach. Others are possible, but overall costs during the phase-in years would not be significantly different.

c. Estimates of Total Nationwide Vehicle Costs by Vehicle Class

EPA used the above sales and phase-in projections along with per vehicle variable and fixed costs to estimate total annual vehicle costs by vehicle class. We have summed the fixed costs for the vehicle categories and have amortized them over the first five years of production at a seven percent discount rate. We multiplied sales by per vehicle variable costs (with the RPE mark-up applied) to calculate total annual variable costs. As discussed above, variable costs are reduced after the second year of production due to the learning curve factor. Tables V-16 through V-20 present total annualized nationwide costs by vehicle class for years 2004 through 2020. Table V-21(A) presents these cost figures summed for all vehicle categories. In addition, Table V-20 and V-21(A) include aggregate costs for MDPV OBDII and ORVR requirements.[9] Table 21(B) provides the non-annualized costs for the Tier 2 program.

[9] The net present value of the fuel savings over the life of the vehicle due to ORVR, estimated to be $5.50, has been subtracted from the system cost of $10.25 for purposes of estimating the aggregate costs.

Table V-16. Annual Nationwide Costs For Tier 2 LDVs

Calendar Year	*Fixed Cost ($)*	*Variable Cost ($)*	*Total Cost ($)*
2004	64,020,172	189,306,353	253,326,525
2005	128,040,345	367,257,308	495,297,653
2006	128,040,345	334,503,997	462,544,342
2007	128,040,345	303,014,320	431,054,665
2008	128,040,345	292,689,560	420,729,905
2009	64,020,172	294,501,019	358,521,192
2010	0	295,973,524	295,973,524
2011	0	297,453,392	297,453,392
2012	0	298,940,659	298,940,659
2013	0	300,435,362	300,435,362
2014	0	301,937,539	301,937,539
2015	0	303,447,227	303,447,227
2016	0	304,964,463	304,964,463
2017	0	306,489,285	306,489,285
2018	0	308,021,731	308,021,731
2019	0	309,561,840	309,561,840
2020	0	311,109,649	311,109,649
2021	0	312,665,198	312,665,198
2022	0	314,228,524	314,228,524
2023	0	315,799,666	315,799,666
2024	0	317,378,665	317,378,665
2025	0	318,965,558	318,965,558
2026	0	320,560,386	320,560,386
2027	0	322,163,188	322,163,188
2028	0	323,774,003	323,774,003
2029	0	325,392,874	325,392,874
2030	0	327,019,838	327,019,838
2031	0	328,654,937	328,654,937
2032	0	330,298,212	330,298,212
2033	0	331,949,703	331,949,703
2034	0	333,609,451	333,609,451

Table V-17. Annual Nationwide Costs For Tier 2 LDT1s

Calendar Year	*Fixed Cost ($)*	*Variable Cost ($)*	*Total Cost ($)*
2004	0	0	0
2005	0	0	0
2006	27,715,184	73,706,372	101,421,556
2007	27,715,184	76,145,235	103,860,420
2008	27,715,184	70,928,248	98,643,433
2009	27,715,184	71,227,705	98,942,890
2010	27,715,184	71,583,844	99,299,028
2011	0	71,941,763	71,941,763
2012	0	72,301,472	72,301,472
2013	0	72,662,979	72,662,979
2014	0	73,026,294	73,026,294
2015	0	73,391,426	73,391,426
2016	0	73,758,383	73,758,383
2017	0	74,127,175	74,127,175
2018	0	74,497,811	74,497,811
2019	0	74,870,300	74,870,300
2020	0	75,244,651	75,244,651
2021	0	75,620,874	75,620,874
2022	0	75,998,979	75,998,979
2023	0	76,378,974	76,378,974
2024	0	76,760,869	76,760,869
2025	0	77,144,673	77,144,673
2026	0	77,530,396	77,530,396
2027	0	77,918,048	77,918,048
2028	0	78,307,638	78,307,638
2029	0	78,699,177	78,699,177
2030	0	79,092,673	79,092,673
2031	0	79,488,136	79,488,136
2032	0	79,885,577	79,885,577
2033	0	80,285,004	80,285,004
2034	0	80,686,429	80,686,429

Table V-18. Annual Nationwide Costs For Tier 2 LDT2s

Calendar Year	*Fixed Cost ($)*	*Variable Cost ($)*	*Total Cost ($)*
2004	0	0	0
2005	0	0	0
2006	27,725,154	149,650,348	177,375,502
2007	92,417,180	515,340,381	607,757,561
2008	92,417,180	518,028,642	610,445,822
2009	92,417,180	487,480,951	579,898,131
2010	92,417,180	489,918,356	582,335,536
2011	64,692,026	492,367,948	557,059,974
2012	0	494,829,787	494,829,787
2013	0	497,303,936	497,303,936
2014	0	499,790,456	499,790,456
2015	0	502,289,408	502,289,408
2016	0	504,800,855	504,800,855
2017	0	507,324,860	507,324,860
2018	0	509,861,484	509,861,484
2019	0	512,410,791	512,410,791
2020	0	514,972,845	514,972,845
2021	0	517,547,710	517,547,710
2022	0	520,135,448	520,135,448
2023	0	522,736,125	522,736,125
2024	0	525,349,806	525,349,806
2025	0	527,976,555	527,976,555
2026	0	530,616,438	530,616,438
2027	0	533,269,520	533,269,520
2028	0	535,935,868	535,935,868
2029	0	538,615,547	538,615,547
2030	0	541,308,625	541,308,625
2031	0	544,015,168	544,015,168
2032	0	546,735,244	546,735,244
2033	0	549,468,920	549,468,920
2034	0	552,216,264	552,216,264

Table V-19. Annual Nationwide Costs For Tier 2 LDT3s

Calendar Year	*Fixed Cost ($)*	*Variable Cost ($)*	*Total Cost ($)*
2004	869,782	8,674,674	9,544,455
2005	2,609,345	26,928,407	29,537,753
2006	7,538,109	79,344,616	86,882,725
2007	19,715,055	213,951,882	233,666,936
2008	28,992,728	324,084,012	353,076,740
2009	28,122,946	310,986,090	339,109,036
2010	26,383,382	300,078,649	326,462,031
2011	21,454,618	301,579,042	323,033,661
2012	9,277,673	303,086,937	312,364,610
2013	0	304,602,372	304,602,372
2014	0	306,125,384	306,125,384
2015	0	307,656,011	307,656,011
2016	0	309,194,291	309,194,291
2017	0	310,740,262	310,740,262
2018	0	312,293,964	312,293,964
2019	0	313,855,433	313,855,433
2020	0	315,424,711	315,424,711
2021	0	317,001,834	317,001,834
2022	0	318,586,843	318,586,843
2023	0	320,179,778	320,179,778
2024	0	321,780,676	321,780,676
2025	0	323,389,580	323,389,580
2026	0	325,006,528	325,006,528
2027	0	326,631,560	326,631,560
2028	0	328,264,718	328,264,718
2029	0	329,906,042	329,906,042
2030	0	331,555,572	331,555,572
2031	0	333,213,350	333,213,350
2032	0	334,879,417	334,879,417
2033	0	336,553,814	336,553,814
2034	0	338,236,583	338,236,583

Table V-20. Annual Nationwide Costs For Tier 2 LDT4s and MDPVs

Calendar Year	*Tier 2 Fixed Costs ($)*	*Tier 2 Variable Costs ($)*	*Tier 2 Total Costs ($)*	*OBD II & ORVR for MDPVs ($)*	*Total With OBD II & ORVR for MDPVs ($)*
2004	0	0	0	5,907,154	5,907,154
2005	0	0	0	6,074,415	6,074,415
2006	0	0	0	6,173,995	6,173,995
2007	0	0	0	6,204,865	6,204,865
2008	5,346,756	61,813,742	67,160,497	6,235,889	73,396,386
2009	15,276,445	180,447,506	195,723,952	6,267,068	201,991,020
2010	15,276,445	173,942,913	189,219,358	6,298,404	195,517,762
2011	15,276,445	160,988,307	176,264,752	6,329,896	182,594,648
2012	15,276,445	161,793,249	177,069,694	6,361,545	183,431,239
2013	9,929,689	162,602,215	172,531,904	6,393,353	178,925,257
2014	0	163,415,226	163,415,226	6,425,320	169,840,545
2015	0	164,232,302	164,232,302	6,457,446	170,689,748
2016	0	165,053,464	165,053,464	6,489,733	171,543,197
2017	0	165,878,731	165,878,731	6,522,182	172,400,913
2018	0	166,708,125	166,708,125	6,554,793	173,262,918
2019	0	167,541,665	167,541,665	6,587,567	174,129,232
2020	0	168,379,373	168,379,373	6,620,505	174,999,878
2021	0	169,221,270	169,221,270	6,653,607	175,874,878
2022	0	170,067,377	170,067,377	6,686,875	176,754,252
2023	0	170,917,714	170,917,714	6,720,310	177,638,023
2024	0	171,772,302	171,772,302	6,753,911	178,526,213
2025	0	172,631,164	172,631,164	6,787,681	179,418,844
2026	0	173,494,319	173,494,319	6,821,619	180,315,939
2027	0	174,361,791	174,361,791	6,855,727	181,217,518
2028	0	175,233,600	175,233,600	6,890,006	182,123,606
2029	0	176,109,768	176,109,768	6,924,456	183,034,224
2030	0	176,990,317	176,990,317	6,959,078	183,949,395
2031	0	177,875,268	177,875,268	6,993,874	184,869,142
2032	0	178,764,645	178,764,645	7,028,843	185,793,488
2033	0	179,658,468	179,658,468	7,063,987	186,722,455
2034	0	180,556,760	180,556,760	7,099,307	187,656,068

Table V-21 (A). Annual Nationwide Costs For Tier 2 LDVs, LDTs and MDPVs

Calendar Year	*Tier 2 Fixed Costs ($)*	*Tier 2 Variable Costs ($)*	*Tier 2 Total Costs ($)*	*Including MDPV OBDII and ORVR Costs ($)*
2004	64,889,954	197,981,026	262,870,980	268,778,135
2005	130,649,690	394,185,715	524,835,406	530,909,821
2006	191,018,792	637,205,332	828,224,125	834,398,119
2007	267,887,764	1,108,451,819	1,376,339,582	1,382,544,447
2008	282,512,192	1,267,544,205	1,550,056,397	1,556,292,286
2009	227,551,928	1,344,643,272	1,572,195,200	1,578,462,268
2010	161,792,192	1,331,497,286	1,493,289,478	1,499,587,881
2011	101,423,090	1,324,330,452	1,425,753,541	1,432,083,437
2012	24,554,118	1,330,952,104	1,355,506,222	1,361,867,767
2013	9,929,689	1,337,606,865	1,347,536,554	1,353,929,907
2014	0	1,344,294,899	1,344,294,899	1,350,720,219
2015	0	1,351,016,374	1,351,016,374	1,357,473,820
2016	0	1,357,771,455	1,357,771,455	1,364,261,189
2017	0	1,364,560,313	1,364,560,313	1,371,082,495
2018	0	1,371,383,114	1,371,383,114	1,377,937,907
2019	0	1,378,240,030	1,378,240,030	1,384,827,597
2020	0	1,385,131,230	1,385,131,230	1,391,751,735
2021	0	1,392,056,886	1,392,056,886	1,398,710,493
2022	0	1,399,017,171	1,399,017,171	1,405,704,046
2023	0	1,406,012,256	1,406,012,256	1,412,732,566
2024	0	1,413,042,318	1,413,042,318	1,419,796,229
2025	0	1,420,107,529	1,420,107,529	1,426,895,210
2026	0	1,427,208,067	1,427,208,067	1,434,029,686
2027	0	1,434,344,107	1,434,344,107	1,441,199,835
2028	0	1,441,515,828	1,441,515,828	1,448,405,834
2029	0	1,448,723,407	1,448,723,407	1,455,647,863
2030	0	1,455,967,024	1,455,967,024	1,462,926,102
2031	0	1,463,246,859	1,463,246,859	1,470,240,733
2032	0	1,470,563,093	1,470,563,093	1,477,591,936
2033	0	1,477,915,909	1,477,915,909	1,484,979,896
2034	0	1,485,305,488	1,485,305,488	1,492,404,796

Table V-21 (B). Non-Annualized Nationwide Vehicle Costs For Tier 2 LDVs, LDTs and MDPVs

Calendar Year	*Tier 2 Fixed Costs ($)*	*Tier 2 Variable Costs ($)*	*Tier 2 Total Costs ($)*
2000	0	0	0
2001	158,787,057	0	158,787,057
2002	160,915,431	0	160,915,431
2003	214,584,860	0	214,584,860
2004	255,856,575	197,981,026	453,837,601
2005	97,985,003	394,185,715	492,170,718
2006	103,494,735	637,205,332	740,700,067
2007	15,074,888	1,108,451,819	1,123,526,707
2008	10,243,046	1,267,544,205	1,277,787,251
2009	0	1,344,643,272	1,344,643,272
2010	0	1,331,497,286	1,331,497,286
2011	0	1,324,330,452	1,324,330,452
2012	0	1,330,952,104	1,330,952,104
2013	0	1,337,606,865	1,337,606,865
2014	0	1,344,294,899	1,344,294,899
2015	0	1,351,016,374	1,351,016,374
2016	0	1,357,771,455	1,357,771,455
2017	0	1,364,560,313	1,364,560,313
2018	0	1,371,383,114	1,371,383,114
2019	0	1,378,240,030	1,378,240,030
2020	0	1,385,131,230	1,385,131,230
2021	0	1,392,056,886	1,392,056,886
2022	0	1,399,017,171	1,399,017,171
2023	0	1,406,012,256	1,406,012,256
2024	0	1,413,042,318	1,413,042,318
2025	0	1,420,107,529	1,420,107,529
2026	0	1,427,208,067	1,427,208,067
2027	0	1,434,344,107	1,434,344,107
2028	0	1,441,515,828	1,441,515,828
2029	0	1,448,723,407	1,448,723,407
2030	0	1,455,967,024	1,455,967,024
2031	0	1,463,246,859	1,463,246,859
2032	0	1,470,563,093	1,470,563,093
2033	0	1,477,915,909	1,477,915,909
2034	0	1,485,305,488	1,485,305,488

B. Gasoline Desulfurization Costs

1. Overview of Changes Since the NPRM

In the NPRM, we indicated that we expected to work with the Department of Energy (DOE) in using the Oak Ridge National Laboratory (ORNL) refinery model to estimate gasoline desulfurization costs. However, we discovered that the ORNL refinery model did not contain representations of certain technologies which we believe are important in the context of desulfurizing gasoline, and this was revealed in several of the early modeling case runs which were conducted by DOE. Thus, we continue to use our refinery model, with a number of adjustments discussed below, to estimate the gasoline desulfurization costs. We compare our refinery modeling results to those by DOE, and other cost studies which we received during this last year, after presenting our cost analysis and results. In general, these other cost studies support our cost estimates.

One of the principal comments to the NPRM which we wanted to address in our FRM cost study is that for the NPRM commenters stated that we inappropriately based our cost estimates on CDTech and and Mobil Oil's Octgain 220 desulfurization technologies which have not yet been "commercially proven."[10] Some refiners feel that these technologies will not have been operating long enough prior to when they have to decide on what technology they will want to use. Thus, these refiners may choose among the several commercially proven desulfurization technologies available today. We incorporated this point of view in our cost analysis for the final rule by assuming that some refiners in 2004 will use today's proven technologies.

Similarly, we became aware that technologies which desulfurize gasoline through adsorption, instead of hydrotreating, are commercially available starting this year. Since these technologies appear to desulfurize gasoline much more efficiently than other processes available today, we believe that a number of refiners will use these technologies, but to only a very limited extent starting in 2005, and increasing after that. We are assuming that these technologies will be used later on because these technologies are so new, and very different from other desulfurization technologies. A more elaborate discussion on all these desulfurization technologies can be found in Section IVB, which is the section containing our discussion of the feasibility of meeting the gasoline sulfur requirements. Many of the small refineries, which must meet a much less stringent set of interim phase-in requirements which will likely allow them to push off their capital investments until 2007 and 2008, are expected to take advantage of this revolutionary technology. The mix of technologies projected to be used in each year is

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a. Our understanding of what refiners generally mean when they say a process is commercially proven is that a process has operated successfully for at least two years in a refinery producing a refinery product.

summarized below in the section on technology cost.

We also received comments on our determination that available desulfurization capacity is available and will be used to desulfurize gasoline first before additional investments are made. Our analysis of the 1996 API/NPRA survey of refining operations and gasoline quality for the NPRM showed that fluidized catalytic cracker feed hydrotreaters are not operating at capacity which we used for an initial reduction in gasoline sulfur. The commenter claimed that these units are already operating at capacity, contrary to what is shown in API/NPRA survey. While we do not have information from refiners to verify or dispute such claims, we were able to address this issue through our analysis of gasoline sulfur levels. Refiners must report their gasoline sulfur levels to EPA to satisfy the RFG and Antidumping program reporting requirements. We analyzed the 1998 gasoline sulfur levels and found that the average sulfur level of domestically produced gasoline dropped from 314 ppm to about 270 ppm. This significant drop in sulfur level may have occurred with the use of excess capacity available from FCC feed hydrotreaters, and probably to meet the requirements of the 1998 requirements of the Reformulated Gasoline Program. Consistent with this new data on gasoline sulfur levels and our assumption that these sulfur reductions resulted from increased FCC feed hydrotreater use, we adjusted the gasoline pool sulfur levels using the 1998 gasoline sulfur data and dropped any assumptions that current gasoline sulfur levels could be reduced with existing FCC feed hydrotreaters. These adjustments made for each PADD are presented below in the section on blendstocks.

We applied two changes to the Octgain cost estimate methodology used in the NPRM which improved our cost estimates for this analysis for the FRM, and this improvement also applied to other fixed bed hydrotreaters as well. In the NPRM, we assumed that the Octgain unit would be used exclusively to treat the entire FCC naphtha stream. However, Mobil Oil, and the other vendors of these fixed bed desulfurization technologies, recommend that their processes be used with a type of distillation column called a splitting column and a catalytic extractive desulfurization unit for treating the light FCC naphtha. For fixed bed hydrotreaters, this combination seems to provide a high level of desulfurization at the lowest cost, so we used it for this analysis. We also based our NPRM cost estimate on the use of a FCC naphtha splitter which was inappropriate for the task. The naphtha splitter we used is for breaking out individual streams for additional processing, such as for separating out olefins for petrochemicals, or producing MTBE. However, for the simple job of creating two substreams for hydrotreating purposes, it is not necessary to boil away the heavier stream, thus the capital and operating costs are much lower. We obtained the cost for using such a splitting column from Mobil Oil. This cost agrees well with the cost of CDTech’s CDHydro column which functions in this manner, so we believe the cost estimate from Mobil Oil is reasosnable and used it in this analysis.

We received a number of comments concerning the cost to refiners of meeting the 80 ppm cap standard. Refiners reported that if the FCC naphtha hydrotreater goes down, then high sulfur FCC naphtha would likely have to be either stored up or sold off until the hydrotreater can be brought on line. Then the untreated, high sulfur blendstock must be dealt with. In most other cost studies, the contractor provided a cost estimate to cover this situation. We added the cost of a storage tank to our cost analysis which would allow for such storage of high sulfur blendstock. Furthermore, we provided excess desulfurization capacity for treating short term stores of high sulfur naphtha. These adjustments to our cost estimation methodology show up in our estimated cost for complying with the low sulfur program.

We maintained many of the aspects of the NPRM analysis. We performed our cost analysis on a PADD-by-PADD basis, based on gasoline production in each PADD (not gasoline consumption). Each PADD is represented by a single refinery which consists of refining units having the average capacity of all refineries of that PADD and which produces gasoline having the average sulfur level of that PADD. This allows us to compare the cost of desulfurizing gasoline between different parts of the country which allowed us to address some of the comments which we received. Like the NPRM, we are assuming that the cost for California refiners to produce non-California low sulfur gasoline is the same as the cost of producing low sulfur gasoline in the rest of the country. Since California refiners are already treating all their gasoline blendstocks, this assumption is probably very conservative. For calculating capital, fixed and variable operating costs, our methodology for the final rule is very similar to what we did for the NPRM, with some modifications, which are outlined below in their respective sections. Our cost analysis is not incremental, studying the cost of a progression of gasoline desulfurization levels, like the analysis for the NPRM, instead we only evaluated the cost of achieving 30 ppm, and we are providing an analysis for meeting a 5 ppm standard, and reviewed the Alliance's cost study for achieving 5 ppm gasoline.

2. Cost Estimation Methodology

a. Technology and Cost Inputs

As we stated above, we are basing our cost analysis for the final rule on a larger group of desulfurization technologies. To facilitate cost calculations with all these desulfurization technologies, we are assigning these technologies into three different groups. The first group comprises those technologies which have already had at least two years of commercial experience. The second group is comprised of CDTech and Octgain 220, which are the improved desulfurization technologies upon which we based the NPRM gasoline desulfurization costs. As stated in the NPRM these technologies are either being demonstrated now, or will start to be demonstrated in the next few months, as described in Chapter IV. The third group comprises desulfurization technologies which work through adsorption. Even though these adsorption technologies are commercially available now, they are newer and different enough from the other technologies that we felt they should be placed into their own group. Because they are newer and significantly different, we believe that most refiners would likely be hesitant in signing a licensing agreement without prior commercial experience, even those refiners which would be willing to risk using a technology such as CDTech which has partial current commercial experience. These technologies are discussed in more detail in the feasibility section. The technologies considered which fall into these various categories are summarized in Table V-22.

Table V-22. List of Desulfurization Technologies by Technology Group

Technology Group	*Desulfurization Technology*
Proven Technologies	Exxon Scanfining, IFP Prime G, Mobil Oil Octgain 125
Improved Technologies	CDTech CDHydro/HDS, Mobil Oil Octgain 220
Adsorption Technologies	Black and Veatch IRVAD, Phillips S-zorb

It is important to point out that there are other desulfurization technologies available which refiners may use. For example, UOP has developed an improved desulfurization technology, and Mobil Oil licenses another desulfurization process named Octgain 100, distinguished by the different catalyst used in the process. However, we decided, as a matter of practicality, to not try to represent all technologies in our cost analysis. It is also important to point out that although Octgain 125 will likely be installed in sour crude oil refineries after 2004, as the program is phasing in, we model the cost of desulfurizing gasoline based on “typical” refineries with average gasoline sulfur levels. For these moderate applications, Mobil Oil recommends that these typical refineries use the Octgain 220 process. It is for this reason that we do not include the Octgain 125 process in the second group of technologies.

These technologies, by virtue of their respective groups, are assumed to be installed for startup in certain years, consistent with what the perceived status is of the technology when a refiner must make the decision on a desulfurization technology (approximately 3- 4 years before). We believe that of the refiners which must meet one of sulfur requirements in 2004, half of them will install a proven technology, while the other half of the refiners would be more willing to rely on a technology which has not been proven. A refiner may use the unproven technology for a variety of reasons. For example, a refiner with poor refining profit margins may assume the risk of using an unproven technology in the hope of desulfurizing its gasoline at a lower cost which will help the refiner to improve its refining margins. Another reason why a refiner may choose an unproven technology is that a refiner may have had a very positive experience with a licensor that could convince the refiner to use that licensor’s technology despite whether the technology has been proven or not. Our assumptions of the mix of technologies to be installed for use starting in any one year of the phase-in is summarized in Table V-23 below. Since there are multiple desulfurization technologies in each group, for our cost analysis, we presume that refiners would use these technologies equally, rather than attempt to determine if refiners would tend to use one more than another, and then project what the percentage of each desulfurization technology used.

Table V-23. Projected Use of Desulfurization Technology Types by Refiners During the Phase-in Period (from Section IV-B)

Initial Year of Full Operation	*Mix of Technology Groups used*
2004	1/2 Proven, 1/2 Improved
2005	3/4 Improved, 1/4 Adsorbent
2006	1/2 Improved, 1/2 Adsorbent
2007 & 2008	1/4 Improved, 3/4 Adsorbent

As discussed in Chapter IV, a number of desulfurization units are projected to begin operating prior to 2004. Five of these units will be demonstration units for the improved and adsorbent technologies. Two to five more units are expected to be operated by refiners desiring to generate early credits or allotments and to use low sulfur gasoline as a marketing tool. These latter units are likely to be a mixture of proven and improved technologies, much like that projected for 2004, possibly with a greater fraction of proven technology. Overall, we represented the cost of these pre-2004 units using the 2004 technology mix.

We acquired process operations information on each of these technologies through our participation with the National Petroleum Council (NPC). During 1999 the NPC was conducting a study of how potential fuel quality control programs will affect the cost and producibility of domestically produced motor vehicle fuels. During this study, the Technology Workgroup of the NPC requested input cost data from many different licensors of gasoline FCC naphtha desulfurization processes to study the cost of desulfurizing gasoline. We obtained that information and we used it in our cost study.[14] This cost input data is summarized in Table V-24.

Table V-24. Process Operations Information for FCC Naphtha Desulfurization Processes
(All Technologies are 95% Efficient for Desulfurizing Gasoline)

	Octgain 125	*Exxon Scanfining*	*IFP Prime G*	*Octgain 220*	*CDTech*	*Black&Veatch IRVAD*	*Phillips S-Zorb*
Capacity (MMbbl/day)	15,000	25,000	24,000	31,000	30,000	30,000	25,000
Capital Cost (MM$)	14.9	16.8	21.7	23.8	18.5	17.9	13.8
Hydrogen Consumption (SCF/bbl)	370	77	126	130	102	Negligible	70
Electricity (KwH/bbl)	2.0	0.61	1.3	1.5	0.44	1.82	-
HP Steam (Lb/bbl)	-	44.8	63	75	24.4	0	4.5
Fuel Gas (BTU/bbl)	84,400	14,500	9300	35,600	33,000	18,300	39,000
Catalyst Cost ($/bbl)	0.43	0.22	0.01	0.22	0.25	0.27	0.27
Cooling Water (Gal/bbl)	250	135	130	225	53.3	16.7	130
Yield Loss (%)	5	0	0.8	0.7	0	4.5	0
Octane Loss (R+M)/2	0	1.0	1.3	0.1	1.0	(2.0)	0.75

Besides these desulfurization technologies, we used additional technologies in our refinery modelling analysis. Depending on the desulfurization case which we were modeling, we used extractive desulfurization units for desulfurizing both light FCC naphtha and light straight run. We also needed to include distillation or splitting columns for fixed bed hydrotreaters for separating the FCC naphtha into two different streams so the light FCC naphtha could be treated by extractive desulfurization and the medium and heavy FCC naphtha could be treated by the hydrotreater. Most of the vendors which license fixed bed desulfurization processes already include the operating and capital costs of both the extractive desulfurization unit and splitting columns in their information submissions, however, we needed to add these costs to the Octgain costs. The process operation information for these other technologies are summarized in Table V-25. The splitting column inputs are from Mobil Oil which provided the information to the NPC Technology Workgroup along with information on their Octgain units. As we stated above, for the NPRM we used the splitter input information from the Oak Ridge National Laboratory refinery model. However, that splitter is really for creating multiple separate substreams out of the FCC naphtha while the Mobil Oil splitter is for creating a simple cut, which is all that is needed for this application. The capital and operating costs for the Mobil Oil splitter are much lower as a result. We provide the ORNL splitter information as a comparison.

In this analysis we also included costs for half of refiners adding an FCC naphtha storage tank.[15] The purpose of the storage tank would be for refiners to store up nonhydrotreated FCC naphtha, for up to 10 days, during a shutdown of the FCC naphtha hydrotreater. During the shutdown, the high sulfur blendstock cannot be blended into gasoline because it would cause the gasoline pool to exceed the 80 ppm cap. Then, after the hydrotreater is brought back on line, the high sulfur FCC naphtha in the storage tank would either be sent to the hydrotreater, in quantities which would not exceed the hydrotreater capacity, or it would be slowly blended into finished gasoline in a manner which allows the refiner to meet the 80 ppm cap. We sized the FCC naphtha hydrotreater large enough to handle the stored naphtha. The capital costs for the storage tank are summarized in Table V-25.

Table V-25. Process Operations Information for Additional Units used for Desulfurization Cost Analysis

	Extractive Desulfurization	*Splitter(Mobil Oil) (used in this analysis)*	*Splitter (ORNL) (used in NPRM)*	*FCC Naphtha Storage Tank*
Capacity (MMbbl/day)	10000	50000	20000	50,000 bbls
Capital Cost (MM$)	3.5	4.1	10.7	0.75
Electricity (KwH/bbl)	---	0.17	2.5	---
HP Steam (Lb/bbl)	---	36	10	---
Fuel Gas (BTU/bbl)	---	---	90000	---
Cooling Water (Gal/bbl)	---	13	---	---
Operating Cost ($/bbl)	0.06	---	---	none*

* 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.

b. Capital Costs

Capital costs are the one-time costs incurred by purchasing and installing new hardware in refineries. The capital costs are calculated similar to how they were calculated for the NPRM, with some differences. Capital costs for a particular processing unit are supplied by the vendors for a particular volumetric capacity and desulfurization efficiency, and these costs are adjusted to match the volume of the particular case being analyzed using the sixth tenths rule.[11] The calendar day volume is increased by 7 percent to size the hydrotreating unit for stream days, the

[11] The capital cost is estimated at this other throughput using an exponential equation termed the "six-tenths rule." The equation is as follows: $(Sb/Sa)^e xCa=Cb$, 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 0.60 for desulfurization units.

days which the unit is operating. Unlike the NPRM, the hydrotreating unit volume is not increased by 15 percent as a safety factor. Instead, a 15 percent factor is applied to the capital costs after the outside battery limit costs and added capital installation costs (for higher labor rates) were calculated, and a 10 percent factor is applied to the operating costs. These two contingency factors are meant to account for costs not accounted for in the principal calculation, such as running the amine and sulfur plants harder for addressing the additional sulfur removed. The 5 percent capital adjustment factor applied to noncommercially demonstrated units for the NPRM is maintained in the final rule. An additional 5 percent factor is applied to size the units larger so that the unit can process untreated blendstock stored up during a shutdown or turnaround.

The capital costs are adjusted further to account for the offsite costs and differences in labor costs relative to the Gulf Coast. The same method for calculating the offsite costs and accounting for differences in labor costs used in the NPRM, which is from Gary and Handewerk, is used here.[16] The offsite and labor factors used for each PADD are summarized here.

Table V-26. Offsite and Location Factors Used for Estimating Capital Costs

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5*
Offsite Factor	1.25	1.25	1.2	1.5	1.25
Location Factor	1.5	1.3	1.0	1.4	1.2

The same economic assumptions used in the NPRM for amortizing the capital costs over the volume of gasoline produced are used for this analysis. These assumptions and the resulting capital amortization cost factors are summarized below in Table V-27. These capital amortization cost factors are used in the following section on the cost of desulfurizing gasoline to represent the capital cost as a cents per gallon cost.

Table V-27. 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

c. Fixed Operating Cost

Operating costs which are based on the cost of capital are called fixed operating costs. These are fixed because the cost is normally incurred even when the unit is temporarily shutdown. These costs are incurred each and every year after the unit is installed and operating. We are using the same cost factors to estimate fixed operating costs in this analysis as what we used for the analysis for the NPRM.

Maintenance cost is estimated to be four percent of capital cost after adjusting to include the outside battery limit cost, and after adjusting the capital cost for the higher labor cost due to the location for PADDs other than PADD 3. This factor is based on the maintenance factor used in the ORNL refinery model.

Other fixed operating costs are accounted for as well, and these generic cost factors are also from the ORNL refinery model. These factors are: three percent of capital costs for buildings, 0.2 percent for land, one percent for supplies which must be inventoried such as catalyst, and two percent for insurance. These factors sum to 6.2 percent which is applied to the total capital cost (after adjusting for offsite costs and location factor) to generate a perennial fixed operating cost.

Annual labor costs are estimated using the cost equation in the ORNL refinery model. Labor cost is very small; on the order of one ten thousandth of a cent per gallon.

d. Variable Operating Cost

Variable operating costs are those costs incurred to run the unit on a day-to-day basis, and are based completely on the unit throughput. Thus, when the unit is not operating, variable operating costs are not being incurred. The operating cost demands (utilities, hydrogen, octane and yield loss) are from the licensors which license the gasoline desulfurization technologies and the basis for the values is 95 percent FCC naphtha desulfurization, since that level of desulfurization adequately exceeded the need by each average refinery modeled for reaching the sulfur target (30 ppm pool sulfur). We used the same variable operating cost factors, for such costs as utilities, hydrogen and octane costs, in this analysis as we used in the NPRM. We summarized these costs in the following table. We are no longer showing the costs for residual oil and diesel fuel, since we are no longer projecting the use of excess FCC feed hydrotreater capacity in achieving the 30 ppm standard. We did make one change in our operating cost calculation methodology. In the NPRM, we estimated the cost of producing steam based on the premise that heat demand for the steam is met by burning fuel gas, and we used the estimated price of fuel gas as our cost basis. For this analysis we are using the same methodology, except our costs are increased upward by a factor of two to be consistent with published cost estimation methodology which estimates the cost of supplying steam as two times the cost of the fuel gas consumed.[17] Our octane cost estimation methodology used for the analysis in the NPRM was corroborated by the cost estimating work by API, which estimated an octane cost just less than ours based on refinery modeling, thus we maintained this cost estimation methodology in our cost analysis.[18] These costs are summarized in Table V-28.

Table V-28. Summary of Costs Taken From EIA and NPC Data Tables *

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5OC*
Electricity (c/KwH)	5.9	3.9	4.2	3.4	5.4
LPG (c/Gal)	19.7	18.4	16.5	17.8	19.7
Gasoline (c/Gal)	27.0	25.9	24.9	28.9	30
Octane Cost (cents)	4.3	2.8	3.5	11.4	9.0
Octane Spread (R+M)/2	5.7	5.2	5.4	5.2	4.6
Fuel Gas ($/MMbtu)	3.75	3.75	3	4.5	3.75
Hydrogen Cost ($/MSCF)	2.5	2.5	2.0	3.0	2.5

* c/KwH is cents per kilowatt-hour, c/Gal is cents per gallon, (R+M)/2 is octane number as determined by Research and Motor octanes divided by two, c/Gal is cents per gallon, $/MMbtu is dollars per million British Thermal Units (Btu), $/MSCF is dollars per thousand standard cubic feet.

e. Determination of Blendstock Sulfur Levels

We maintained the alkylate, coker, and light straight run sulfur levels estimates which we summarized in the NPRM; however, we made an adjustment in the FCC gasoline sulfur levels based on the lower average gasoline sulfur levels in 1998. For the NPRM, we provided a sulfur balance for an average refinery in each PADD to establish the volumes and sulfur levels of blendstocks which contribute significantly to the pool sulfur level (FCC naphtha, alkylate, straight run, and coker). The sulfur levels for these streams were volume-weighted and compared to the pool gasoline sulfur level. If the calculated pool sulfur level did not agree with the pool sulfur level, then the FCC gasoline sulfur level or volume was adjusted, under the presumption that the noncalculated value is more likely to be correct. This exact process is explained in detail below in the discussion on how the calibration was carried out for each

PADD.

The volumes and sulfur levels of the various blendstocks are established based on information from different sources. FCC gasoline volumes and sulfur levels were taken from the 1996 API/NPRA survey, or the RFG baseline data base. The RFG data base was used when the API/NPRA data for a PADD was incomplete or internally inconsistent, as described further below. The RFG data base was not used first because because not all refiners reported their blendstock sulfur levels. Coker gasoline volumes and sulfur levels were taken from the 1996 API/NPRA survey. Straight run sulfur levels and volumes are from the 1989 NPRA survey.

Alkylate sulfur levels are set at 10 ppm. This value was arrived at through an analysis of alkylate sulfur levels from the baselines submitted for the RFG program, and a review of alkylate sulfur levels in various refining consultant refinery models. From the 1990 RFG baseline database, alkylate sulfur levels from nine refineries were averaged together. The averaged value was determined to be 22 ppm, however, one refinery had a sulfur level of over 130 ppm. Since the promulgation of the NPRM, we contacted that refiner with the high alkylate sulfur level and found out that the operations of their alkylate unit has improved since 1990, and their alkylate is now averaging about 20 ppm sulfur. When we averaged that sulfur level with the alkylate sulfur levels of other refineries, the average alkylate sulfur level dropped to 7 ppm for those refineries.

For the NPRM, we also contacted several refining industry consultants to find out what alkylate sulfur levels they used in their refinery models. The alkylate sulfur levels in those refinery models averaged about 10 ppm (the values ranged from 0 to 25 ppm). For the final rule, we are maintaining the 10 ppm average sulfur level for alkylate we used for the NPRM, since both the RFG data base and refining industry consultants generally support this level.

Other blendstocks, such as isomerate, reformate, raffinate, dimate, poly gasoline, hydrocrackate, aromatics, butane and any oxygenates which may be blended into gasoline, are all assumed to make a negligible sulfur contribution to the gasoline sulfur pool. We believe that for an analysis of the cost of achieving a 30 ppm gasoline pool sulfur level, that this assumption is appropriate. Even if their sulfur contribution is somewhat higher, both the 15 and10 percent capital and operating cost contingency factors and the excess 5 percent treating capacity of the FCC naphtha hydrotreater are conservative estimates, which could offset the additional desulfurization treatment cost of these other streams (or for further desulfurizing FCC naphtha to compensate for the small amount of sulfur in these other streams).

The gasoline pool sulfur levels (not calculated from blendstocks) were taken from either the API/NPRA survey or the RFG data base and were compared to the values calculated from the sulfur-containing blendstocks. If there was disagreement, we adjusted one or the other, as summarized below.

For the NPRM we assumed that projected unused FCC feed hydrotreating capacity would be used first by the average refinery to reduce their FCC naphtha sulfur level, and additional hydrotreating would be estimated from the revised FCC naphtha sulfur level. As stated above, comments which we received on our proposed rule stating that such capacity does not exist raised uncertainty about how much excess capacity there might be both now and projecting availability in the 2004 timeframe.

New analysis since the promulgation of the NPRM of the gasoline sulfur levels in 1998 shows that gasoline sulfur levels dropped significantly since 1997, possibly due to refiners having to meet the federal RFG and Antidumping requirements using the Complex Model. One possible explanation of how this reduction came about was that refiners used their existing spare FCC feed hydrotreater capacity to reduce their gasoline sulfur levels. Assuming that this is the case, we will use the new gasoline sulfur levels for each PADD to recalculate the FCC naphtha sulfur levels. All sulfur levels calculated are volume-weighted, not refinery-weighted. These adjustments are summarized below in the section on each PADD.

PADD 1 - The 1996 API/NPRA survey only collected data from refiners which comprise half of the gasoline production in PADD 1 (nine reported gasoline quality, and only five reported FCC sulfur level); thus, it did not seem viable to use that survey data. Instead, the RFG baseline data was used exclusively (based on data from 11 refineries). The average gasoline pool sulfur values for each refinery were obtained from the 1995/1996 data reported by refiners to EPA. When all the refineries' average gasoline sulfur values were averaged together, the average ended up being 215 ppm. The FCC gasoline sulfur values for each refiner were used to estimate the average sulfur level of FCC gasoline for the PADD, which was estimated to be about 460 ppm (although, this value seems low compared to the straight run sulfur level from the 1989 NPRA survey, which was reported to be 330 ppm). The FCC sulfur level of any refinery was adjusted if the 1995/1996 gasoline sulfur level was significantly different from the level reported in the 1990 baseline submission. Based on the RFG baseline submissions, the FCC volume was calculated to comprise 46 percent of the gasoline pool. The blendstock calculated pool sulfur level was higher than the calculated gasoline sulfur level, so the FCC volume was adjusted downward from 46 percent to 42 percent to result in a pool sulfur level of 215 ppm. The gasoline production volume for the average refinery in PADD 1 is about 77 thousand barrels per day.

We analyzed whether these figures need to be adjusted to account for the implementation of Phase II RFG in 2000. Phase II RFG plays an important role for PADD 1 refiners since those refiners produce more than 60 percent of its gasoline as RFG. The average gasoline sulfur level was calculated for RFG in 1995 and 1996 found to be about 150 ppm. Since we expect Phase II RFG to be about 150 ppm, no changes in sulfur level are expected to occur to produce Phase II RFG.

In 1998, PADD 1 gasoline sulfur levels averaged 189 ppm, which is 27 ppm lower than the previous value. FCC sulfur levels are recalculated to be 381 ppm based on the lower pool sulfur level.

The PADD 1 blendstock sulfur levels and relative volumes are summarized in Table V-29.

Table V-29. PADD 1 Gasoline Blendstock and Pool Sulfur Levels and Pool Fractions

	FCC	*Alkylate*	*Straight Run*	*Coker*	*Gasoline Pool Sulfur Level*
Sulfur (ppm) NPRM FRM	442 381	10	343	3289	
Percentage of gasoline pool	42	10	4	0.44	
Contribution to pool (ppm) NPRM FRM	185 160	1	14	14	214 189

PADD 2 - The API/NPRA survey data for the gasoline pool sulfur level and the FCC sulfur and volume was used. According to the survey data, PADD 2 FCC gasoline has a sulfur level of 924 ppm and it comprises about 27 percent of the gasoline pool. However, based on that FCC sulfur level and volume and other blendstock sulfur levels and volumes, the gasoline pool would have a sulfur level of 260 ppm which is lower than the pool average of 338 ppm based on the API/NPRA survey. To account for this discrepancy, the FCC contribution to the gasoline pool was increased to 35 percent. Since PADD 2's RFG production is only 11 percent, Phase 2 RFG is presumed to have no effect on the average sulfur level of PADD 2. The gasoline production volume for the average refinery in PADD 2 is about 66 thousand barrels per day.

In 1998, PADD 2 gasoline sulfur levels averaged 276 ppm, which is 62 ppm lower than the previous value. FCC sulfur levels are recalculated to be 745 ppm based on the lower pool sulfur level.

The PADD 2 blendstock sulfur levels and relative volumes are summarized in Table V-30.

Table V-30. PADD 2 Gasoline Blendstock and Pool Sulfur Levels and Pool Fractions

	FCC	*Alkylate*	*Straight Run*	*Coker*	*Gasoline Pool Sulfur Level*
Sulfur (ppm) NPRM FRM	924 745	10	397	0	
Percentage of gasoline pool	35	13	3.4	0	
Contribution to pool (ppm) NPRM FRM	323 261	1	14	0	338 276

PADD 3 - According to the 1996 API/NPRA survey FCC gasoline comprises 35 percent of the gasoline pool and the sulfur level of that blendstock is 722 ppm. When considering all the blendstocks together, they result in a pool sulfur level of 271 ppm. However, the 1996 API/NPRA survey has PADD 3 pool sulfur levels at 305 ppm. To make the blendstock agree with the pool sulfur level, the PADD 3 FCC gasoline volume was increased from 35 percent of the pool to 40 percent. The gasoline production volume for the average refinery in PADD 3 is about 75 thousand barrels per day.

In 1998, PADD 3 gasoline sulfur levels averaged 288 ppm, which is 19 ppm lower than the previous value. FCC sulfur levels are recalculated to be 673 ppm based on the lower pool sulfur level.

The PADD 3 blendstock sulfur levels and relative volumes are summarized in Table V-31.

Table V-31. PADD 3 Gasoline Blendstock and Pool Sulfur Levels and Pool Fractions

	FCC	*Alkylate*	*Straight Run*	*Coker*	*Gasoline Pool Sulfur Level*
Sulfur (ppm) NPRM FRM	722 673	10	139	3255	
Percentage of gasoline pool	40	14	2.8	0.42	
Contribution to pool (ppm) NPRM FRM	288 269	1	4	14	307 288

PADD 4 - According to the 1996 API/NPRA survey, 31 percent of the gasoline pool comes from FCC gasoline blendstock, and the sulfur level of that blendstock is 1100 ppm. When considering the sulfur contribution from the other blendstocks, the pool average sulfur level is calculated to be about 350 ppm. However, according to the 1996 API/NPRA survey the pool sulfur level was about 260 ppm, and this pool sulfur level is corroborated by 1995/1996 gasoline sulfur data reported by refiners to EPA. The PADD 4 FCC gasoline sulfur level from refiner baseline submissions, after adjusting for changes in gasoline sulfur levels from when the baseline were submitted in 1995/1996 (based on simple ratioing), averaged 760 ppm. This FCC sulfur level was used and, combined with other blendstocks, resulted in a pool sulfur level of 263 ppm. The gasoline production volume for the average refinery in PADD 4 is about 19 thousand barrels per day.

In 1998, PADD 4 gasoline sulfur levels averaged 282 ppm, which is 17 ppm higher than the previous value. FCC sulfur levels are recalculated to be 823 ppm based on the higher pool sulfur level.

The PADD 4 blendstock sulfur levels and relative volumes are summarized in Table V-32.

Table V-32. PADD 4 Gasoline Blendstock and Pool Sulfur Levels and Pool Fractions

	FCC	*Alkylate*	*Straight Run*	*Coker*	*Gasoline Pool Sulfur Level*
Sulfur (ppm) NPRM FRM	762 823	10	122	0	
Percentage of gasoline pool	31	12	21	0	
Contribution to pool (ppm) NPRM FRM	236 255	1	26	0	263 282

PADD 5 OC - Based on the 1996 API/NPRA survey data, the FCC gasoline sulfur level was 666 ppm (based on only four refineries), and the volume was 38 percent of the entire gasoline pool. However, when all the blendstock sulfur levels and volumes were combined together, the calculated gasoline pool sulfur level would only average 256 ppm which is much lower than the pool sulfur levels from the API/NPRA gasoline parameter data, which averaged 480 ppm. Based on the RFG data base, the pool sulfur level for PADD 5 was 510 ppm, and the FCC gasoline sulfur level for the 6 refineries was about 1200 ppm. The RFG baseline FCC sulfur level was much more consistent with the average gasoline sulfur level and thus was used for cost estimation. To match the blendstock sulfur levels with the RFG data base average pool sulfur level (510 ppm), the fraction of FCC gasoline to the rest of the gasoline pool was increased from 38 percent to 42 percent. The gasoline production volume for the average refinery in PADD 5, not including California refineries, is about 27 thousand barrels per day.

In 1998, PADD 5 gasoline sulfur levels averaged 301 ppm, which is 205 ppm lower than the previous value. FCC sulfur levels are recalculated to be 710 ppm based on the lower pool sulfur level.

The PADD 5 outside of California blendstock sulfur levels and relative volumes are summarized in Table V-33.

Table V-33. PADD 5 Outside of California Gasoline Blendstock and Pool Sulfur Levels and Pool Fractions

	FCC	*Alkylate*	*Straight Run*	*Coker*	*Gasoline Pool Sulfur Level*
Sulfur (ppm) NPRM FRM	1197 710	10	41	0	
Percentage of gasoline pool	42	10	5.9	0	
Contribution to pool (ppm) NPRM FRM	503 298	1	2	0	506 301

Gasoline Volume - To estimate the aggregate capital and operating cost of desulfurizing gasoline by PADD, and for volume weighting the separate PADDs to calculate the national average cost, the gasoline production volumes for each PADD and the production and consumption values for the Nation as a whole are used. The future volume of gasoline produced is based on the increase in consumption summarized later on in this Section. These values are the same as those used in the NPRM.

These values are summarized below in Table V-34.

Table V-34. Projected Volume of Gasoline Produced by an Average Refinery in each PADD and Projected Gasoline Consumption for the U.S.* in 2004

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5OC*	*U.S. OC*
Gasoline Produced by Avg. Refinery (MBbl/day)	77	66	76	19	27	-
Total Gasoline Produced (MMBbl/yr)	404	764	1430	107	166	2872
Gasoline Consumed (MMBbl/yr)						3192

* California gasoline not included.

f. Phase-In Desulfurization

To estimate the capital and per-gallon cost of the gasoline desulfurization program based on our projected use of gasoline desulfurization technologies, we needed to estimate the volume of gasoline each year which would have to be desulfurized to enable refiners to meet the standard which applies in that particular year. To make this estimation, we needed to project for what year refineries will need to have new capital investments installed to meet the requirements of this gasoline sulfur program. We made such an assessement, accounting for the small refiner and ABT programs contained in the final rule, as well as the geographic phase-in, and it is summarized in Section IV.

Based on this analysis we tallied the production volume of gasoline desulfurized for each year and by PADD. This allowed us to calculate our estimated capital and per-gallon costs each year. Our estimate incorporates the temporary exemption for the geographical phase-in as well as the small refiners. These volumes are summarized in Table V-35.

Table V-35. Cumulative Fraction of the Gasoline Pool Desulfurized by PADD and by Year

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5OC*
2004*	0.25	0.63	0.65	0.15	0.66
2005	0.36	0.68	0.74	0.15	0.66
2006	0.99	0.93	0.96	0.15	1
2007	0.99	0.93	0.97	0.88	1
2008+**	1	1	1	1	1

*   Includes early desulfurization units prior to 2004.
** Includes gasoline already meeting the 30 ppm standard which we included in our baseline gasoline sulfur level for estimating cost, thus it is appropriate to assign some cost to these gallons of gasoline.

g. Decreasing Costs in Future Years

Like the analysis completed for the NPRM, we are presuming that desulfurization costs decrease in future years, however, our methodology is somewhat different. For the NPRM, we presumed that operating costs decrease due to an improvement in catalyst technology. Based on this presumption, we projected that operating costs, including catalyst cost, hydrogen cost, octane cost, and yield loss, would decrease by 20 percent after two years. We also assumed that with debottlenecking, fixed operating costs would stay the same in total and decrease on a per-barrel basis.

Our analysis for the Final Rule incorporates operational cost reductions, but not the debottlencking cost reduction. The presumption here is that refiners will either operate the proven technologies more efficiently, or they would simply change out the catalyst to use the lowest cost fixed bed desulfurization catalyst, which would result in a 20 percent reduction in hydrogen consumption cost, octane recovery cost, yield loss, and catalyst cost starting in the third year. For example, if refiners initially installed a Mobil Oil Octgain 125 process and then later on decided to install the Octgain 220 process (which could be changed out after operating the unit for two years when the catalyst desulfurization efficiency begins to degrade), we estimate, based on the vendors information and our cost factors, that the Octgain 220 process would lower the aggregate cost of the desulfurization unit by 20 percent. But based on the operating cost alone, we estimate the cost savings to be almost 30 percent. Since this case is only one of several proven technologies and there may not be as dramatic as a reduction for the others, we only used

20 percent as our operational cost improvement. We did not assume that the same operational benefits applied to improved and adsorption technologies. We do presume, though, that after the proven and improved desulfurization units reach the end of their economic life, which is after 15 years, they would be replaced by the lower cost adsorption units.

3 The Cost of Desulfurizing Gasoline

a. EPA Costs

The refinery blendstock sulfur levels, the vendor desulfurization technology information, the various cost inputs, and the various desulfurization assumptions described above were combined together in our refinery model to estimate the cost of desulfurizing gasoline from the base sulfur level, down to 30 ppm. As stated above, we presume that refiners would choose a mix of proven and improved desulfurization technologies to meet the requirements of the first year of the program. Then for meeting the program requirements after 2004, some refiners would choose to use lower cost adsorption technologies for 2005, with more and more of them doing so toward the later years. For each technology group, we presume that equal use of each technology would be used. To estimate costs for each year based on this methodology, we used the projected volume of gasoline desulfurized for each PADD during each year of the phase-in period. To estimate national average costs, we volume weighted the PADD-specific cost estimates.

Based on this methodology we estimated the aggregate operating and capital cost, and the per-gallon cost, for the U.S. refining industry as a whole, each year starting in 2004. As expected the program's per-gallon cost decreases over time as lower cost desulfurization technology is implemented until 2008 when the last desulfurization units are installed. In 2006, a portion of the proven technologies' operational costs decrease. After 2008, the costs are constant until 2019 when the initial desulfurization units installed in 2004 reach the end of their useful life, and are replaced by adsorption units, the lowest cost desulfurization technologies. The aggregate operating costs increase due to the constant increase in growth in gasoline demand. These costs are summarized in Table V-36.

Table V-36. Estimated U.S. Aggregate Operating and Capital Cost, and Per-Gallon Cost of Desulfurizing Gasoline to 30 ppm (7% ROI, Before Taxes, $1997)

Year	*Estimated Aggregate Operating Cost ($Billion)**	*Estimated Aggregate Capital Cost ($Billion)*	*Estimated Total Aggregate Cost ($Billion)*	Estimated Per-Gallon Cost (c/gal)
2003	-	2.61**	2.61	
2004	1.21	0.29	1.50	1.95
2005	1.36	1.16	2.52	1.90
2006	1.84	0.34	2.18	1.70
2007	1.95	0.14	2.09	1.71
2008	2.02	-	2.02	1.70
2009	2.04	-	2.04	1.70
2010	2.05	-	2.05	1.70
2011	2.07	-	2.07	1.70
2012	2.08	-	2.08	1.70
2013	2.10	-	2.10	1.70
2014	2.12	-	2.12	1.70
2015	2.13	-	2.13	1.70
2016	2.14	-	2.14	1.70
2017	2.16	-	2.16	1.70
2018	2.17	2.20	4.37	1.70
2019	1.65	0.29	1.94	1.32
2020	1.63	1.24	2.87	1.30
2021	1.61	0.40	2.01	1.26
2022	1.63	0.17	1.80	1.26
2023	1.66	-	1.66	1.26
2024	1.68	-	1.68	1.26
2025	1.71	-	1.71	1.26
2026	1.73	-	1.73	1.26
2027	1.76	-	1.76	1.26
2028	1.78	-	1.78	1.26

Year	*Estimated Aggregate Operating Cost ($Billion)**	*Estimated Aggregate Capital Cost ($Billion)*	*Estimated Total Aggregate Cost ($Billion)*	Estimated Per-Gallon Cost (c/gal)
2029	1.80	-	1.80	1.26
2030	1.83	-	1.83	1.26

* Based on fuel consumption data summarized further below in Section V.
** Includes investments made to produce low sulfur gasoline before 2004 to accumulate credits.

Table V-36 shows that the aggregate capital cost to the U.S. refining industry for meeting the proposed 30 ppm sulfur standard during the initial phase-in is expected to total about 4.5 billion dollars. The program's phase-in causes the capital investments to be spread out over several years, with a little more than half of the capital investments being spent either during, or prior to the year 2004. This level of capital expenditure is less than previous capital expenditures made by the refining industry for environmental programs. As we discussed in the NPRM, during the early nineties the U.S. refining industry invested one to two billion dollars per year in capital for environmental controls for their refining operations; this cost represented about one third of the total capital expenditures made by refiners for their refineries. Considering that these expenses made in the early '90s were incurred by less than three quarters of the refining industry, we believe that a program requiring the entire industry to spend, on average, about one billion dollars of capital costs per year over several years is not overly burdensome from an economic perspective. The relative value of the costs and benefits of this program are discussed in Chapter VII.

As stated above we estimated per-gallon cost by PADD based on an average refinery for each PADD using different amortization premises. In Table V-37 below, costs are shown for amortizing capital at a 7 percent rate of return on investment (ROI) before taxes which is to represent the cost to society. Then we provide a range of costs which is meant to represent the cost based on a rate of return on capital consistent with how refiners may recover their capital costs. This range is 6 to 10 percent ROI after taxes. To simplify this comparison, we are presenting these per-gallon costs for 2008, the year when the costs stabilize.

Table V-37. Post Phase-in Cost (year 2008) of Desulfurizing Gasoline to 30 ppm Based on Different Capital Amortization Rates

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5OC	National Average
Societal Cost 7% ROI before Taxes	2.00	1.65	1.52	2.32	2.63	1.70
Capital Payback (6% ROI, after Taxes)	2.04	1.69	1.54	2.41	2.67	1.73
Capital Payback (10% ROI, after Taxes)	2.22	1.85	1.65	2.76	2.87	1.87

Our analysis shows that the per-gallon cost of desulfurizing gasoline to 30 ppm varies from PADD to PADD. PADDs 2 and 3 would experience lower costs than the other PADDs. Because of the smaller size of the refineries which increases the cost of installing capital, and because of the higher refinery operating cost, producing low sulfur gasoline in PADD 4 is expected to be the most expensive, and, in the analysis for the NPRM, was about twice as costly to desulfurize gasoline as PADDs 2 and 3. However, because the PADD 4 refineries are subject to less stringent interim standards until 2007 and 2008 under the small refiner and geographical phase-in provisions, the costs are much lower and only 50 percent higher than those of PADDs 2 and 3. A national average cost is calculated by volume-weighting the various PADDs. The result is an average national societal cost of about 1.7 cents per gallon to desulfurize gasoline down to 30 ppm in 2008 after the program is fully phased-in.

To help the reader better understand the cost of the program for a typical refinery, the per-refinery capital and operating costs, and the estimated yearly aggregate capital and operating cost for each PADD and for the country as a whole of meeting a 30 ppm sulfur standards is summarized in Table V-38 below.

Table V-38. Estimated Average Per-Refinery and Aggregate Capital and Operating Cost of Desulfurizing Gasoline to 30 ppm

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5OC*	*National*
Avg. per-refinery capital cost ($MM)	64	50	38	26	26	44
Avg. per-refinery operating cost ($MM)	20	15	17	5	11	16
Aggregate capital cost	691	1342	1674	327	259	4294
Aggregate operating cost	193	341	663	53	92	1343

Table V-38 shows that, on average, refiners would have to pay out $44 million in capital costs for each refinery to lower gasoline sulfur to 30 ppm. In addition, each refinery would incur about 16 million dollars per year in operating costs. While the smaller refiners in PADD 4 are expected to pay out less than other refiners, their costs are higher on a per-gallon basis. Since these figures are averages, larger refineries with high gasoline sulfur levels will experience higher total costs, while smaller refineries with lower sulfur levels will experience lower total costs. The aggregate operating cost to the U.S. refining industry is expected to be about 1.3 billion dollars per year.

b. Other Low Sulfur Cost Studies

i. American Petroleum Institute (API) Study

API funded a study by Mathpro to estimate the cost of desulfurizing gasoline in PADDs 1, 2 and 3 down to 40 ppm.[19] Their study was based on CDTech and Mobil Oil Octgain 220 used in a notional refinery which is designed to represent all the refineries in those three PADDs. That study estimated the cost of desulfurizing gasoline down to 40 ppm to be 2.6 c/gal for Octgain, and 2.25 c/gal for CDTech. The study amortized capital investment at a 10 percent rate of return, which is higher than the ROI which we use to evaluate and compare cost-effectiveness. In addition the Mathpro study allocated 0.5 c/gal for ancillary costs, such as reblending of offspec batches and accounting for overoptimization. These are costs which Mathpro feels is applicable, however, Mathpro has not justified these costs.

To compare our two studies, it is important to place their cost analysis on the same basis as ours. We did that by adjusting their capital cost to reflect a capital amortization rate consistent with a 7 percent ROI before taxes. We summarized the initial costs and the subsequent adjustments in the following table. The API costs increase by 0.25 c/gal for meeting a 30 ppm specification.[20] We next adjusted the 30 ppm cost to base the capital costs on a 7 percent ROI, which decreased the cost to 2.2 c/gal. The costs are even more in line with our costs if some of the ancillary costs are not justified. These costs are summarized in Table V-39.

Table V-39. API Gasoline Desulfurization Estimate, Adjusted and Compared to EPA's
(API cost adjustments are sequential which leads to the comparison with our costs)

Description	*Cost (c/gal)*	
	CDTech	Octgain
API study initial cost for meeting 40 ppm standard	2.25	2.6
API Study: Average CDTech & Octgain cost for 40 ppm std.	2.4	
Adjusted API cost estimate to include incremental cost to meet 30 ppm std. by Mathpro cost study for the Alliance	2.65	
EPA adjusted API Estimated cost based on 7% ROI before taxes	2.2	
EPA cost based on CDTech and Octgain 220 7% ROI before taxes	1.7	

ii. National Petrochemical and Refiners Association (NPRA) Study

NPRA funded a study by Mathpro to estimate cost to PADD 4 refineries of meeting a 40 ppm gasoline sulfur standard.[21] The study yielded a cost of 5.7 c/gal, however, we reviewed the bases for the study and a number of assumptions used in the study led to the much higher gasoline desulfurization cost than our analysis. First, the study assumed that only Octgain 125, which is a proven desulfurization technology, would be used. Then, their cost inputs for Octgain 125 are the older, conservative ones which were abandoned by Mathpro in the later study funded by API. Mathpro's analysis of the difference in cost between the two versions of Octgain 125 processes is about 1 c/gal for PADDs 1 - 3. Furthermore, like our NPRM analysis, the splitting column used in the NPRA analysis to separate the FCC naphtha into two distinct streams for selectively treating only the heavier part of the FCC naphtha was for an overly conservative column for boiling the entire stream, not intended for making a crude cut for gasoline hydrotreating.

We estimated the cost to PADD 4 refiners to desulfurize their gasoline, based on our finalized program which exempts PADD 4 refineries for the first three years, and thus we assume that most will install absorption desulfurization technology. Based on this methodology, we derived a cost of 2.5 c/gal.

In the process of evaluating that cost, we looked at what the cost would be if PADD 4 refiners had to put in Octgain 125 desulfurization technology, and we can even estimate what it would cost these refineries if they were to install the full boiling range FCC naphtha splitter which, of course, is unnecessary for the simple cuts needed for hydrotreating. We used these cost estimates to adjust the NPRA costs downward to see what NPRA costs might be if they used the more efficient desulfurization and processing equipment, and revised capital amortization factors. We estimate that the 5.7 c/gal NPRA cost would decrease to 5.2 c/gal if their capital cost were amortized by a 7 percent ROI before taxes. Then if their cost estimate would have been based on the revised Octgain 125 cost, we estimate that their cost would decrease to 4.2 c/gal. Next, if their estimated cost were based on a more efficient FCC naphtha splitting column, we estimate that their gasoline desulfurization cost would decrease to 3.5 c/gal. Finally, if their estimated gasoline desulfurization cost were based mostly on adsorption desulfurization technology, we estimate that their estimated cost would decrease to about 2 c/gal, which would be a little higher if their cost estimate would have been for meeting a 30 ppm standard. These costs are summarized in Table V-40.

Table V-40. NPRA PADD 4 Gasoline Desulfurization Estimate, Adjusted and Compared to EPA's
(NPRA cost adjustments are sequential which leads to the comparison with our costs)

Description	*Cost (c/gal)*
NPRA estimated cost for PADD 4 refineries meeting 40 ppm standard based on 10% ROI after taxes	5.7
Incremental Adjustments by EPA	
To 7% ROI before taxes	5.2
To reflect new Octgain 125 cost	4.2
To reflect optimized splitting column	3.5
To reflect more efficient adsorption desulfurization technology	1.7
EPA cost for PADD 4 refineries meeting a 30 ppm standard based primarily on adsorption technology and based on a 7% ROI before taxes	2.5

iii. Association of International Automobile Manufacturers (AIAM) Study

AIAM funded a study by Mathpro to analyze the cost of meeting a 30 ppm standard in PADD 4 using improved desulfurization technology.[22] Mathpro used a spreadsheet to estimate the cost in a refinery-by-refinery analysis of meeting the low sulfur specification. The study assumed that CDTech would be the desulfurization technology used. The analysis estimated that it would cost 3.14 c/gal for PADD 4 refiners to meet the 30 ppm sulfur standard. However, the cost estimate is based on a 15% ROI, and adjusting the cost estimate to be based on a 7% ROI before taxes, reduces the cost estimate to 2.41 cents per gallon.

If we only base our cost to PADD 4 refiners of desulfurizing their gasoline on CDTech, our refinery model estimates that it would cost PADD 4 refiners 3.2 c/gal. Thus, our cost is much more conservative than that by Mathpro. This most likely reflects the higher labor costs for the installation of capital for PADD 4 which we use.

Table V-41. AIAM Gasoline Desulfurization Estimate for PADD 4, Adjusted and Compared to EPA's

Description	*Cost (c/gal)*
Mathpro's cost for desulfurizing gasoline to 30 ppm in PADD 4 based on 15% ROI	3.14
Mathpro's desulfurization cost based on 7% ROI, before taxes	2.14
EPA's cost for desulfurizing gasoline in PADD 4 using CDTech and based on 7% ROI before taxes	3.2

iv Department of Energy (DOE) Study

The Department of Energy used their refinery modeling resources at the Oak Ridge National Laboratory to estimate the cost of desulfurizing gasoline for the average refinery.[23] [24] DOE also sought to determine if desulfurization costs varied significantly between average refineries and those for whom gasoline desulfurization might be more challenging. To answer these two questions, they evaluated desulfurization costs for two classes of refineries: mid-capability and challenged. In their analysis, the mid-capability refineries processed crude oil with a sulfur content of 1.6 weight percent, partially hydrotreated FCC feed and produced gasoline with an average sulfur content of 200 - 240 ppm. The challenged group processed crude oil with a sulfur content of 1.94 weight percent, did not hydrotreat FCC feed and produced gasoline with an average sulfur content of 500 ppm. The study was parametric, evaluating the cost of desulfurizing gasoline to 50, 30 and 10 ppm for the mid-capability refinery, and 30 ppm for the challenged refinery. The estimated costs for 10, 30 and 50 ppm sulfur are summarized in Table V-42.

Table V-42. DOE Gasoline Desulfurization Estimate, Adjusted and Compared to EPA's

Description	*Cost (c/gal)*		
	50 ppm	30 ppm	10 ppm
Mid-capability refinery Challenged refinery Based 10% ROI after taxes	2.1 ---	2.9 3.4	9.0 ---
Mid-capability refinery Challenged refinery Adjusted to 7% ROI before taxes	1.9 ---	2.6 2.4	6.7
EPA national average cost to produce 30 ppm gasoline; 7% ROI before taxes		1.7	---

For case where mid-capability refineries produced 30 ppm gasoline, the refinery model chose CDTech as the FCC naphtha hydrotreater. However, the model also chose to install a FCC naphtha splitter, and treat some of the light FCC naphtha with a catalytic extractive desulfurizing unit, and send some of the FCC naphtha to the naphtha hydrotreater/reformer train for hydrotreating and octane recovery. Splitting the FCC naphtha is an integral part of the CDTech unit, so it is unclear why the refinery model chose to install an additional splitter in front of the CDTech unit. Also, the FCC naphtha splitting column simulated by the refinery model is a full boiling range column. This type of column is more costly than a simpler two cut splitter which should be sufficient for this application, as we discussed above. Finally, it is also not clear why the refinery model chose to route some of the FCC naphtha to the reformer hydrotreater. We identified this technique above as a way to reduce sulfur operationally in the period of time prior to installation of a FCC gasoline desulfurization unit. However, this technique is generally not considered to be beneficial in the long run, as running FCC naphtha through the reformer affects the yield and octane of the reformate. It is not clear how this may have affected the costs projected by the DOE model, as the effect of running FCC naphtha through the reformer on reformate yield and octane was not presented. However, along with the inclusion of the full-range splitter, this could have increased costs beyond that necessary to achieve the sulfur standard.

The study's estimated high cost of producing 10 ppm gasoline also appears to be explainable. The refinery model did not include the severe hydrotreating representations of the improved and low cost, proven technologies. The Mathpro model and our model include these severe desulfurization representations. We present cost information in in Section c. below for more greater than 95 percent efficient desulfurization. A comparison of these costs to those presented above in Tables V-24 and V-25 for 95 percent efficient desulfurization shows that increasing desulfurization efficiency increases costs, but not to the degree indicated by the results of DOE's refinery model. Thus, the absence of these more efficient units appears to have had a major impact on the refinery model's ability to achieve the 10 ppm standard. For example, the DOE refinery model estimated that the achieving the 10 ppm standard would cost $660 million in capital costs per refinery. This is more than an order of magnitude higher than the cost of a FCC gasoline hydrotreater and many times higher than the cost of an FCC feed hydrotreater coupled with a FCC gasoline hydrotreater. Thus, it appears that the model simply did not include cost effective means with which to achieve such low sulfur levels.

Regarding challenged refineries, the DOE study shows that it is only slightly more costly for the challenged refineries to meet the 30 ppm standard than for the mid-capability refineries. This difference disappears altogether using EPA's lower capital cost amortization factor based on a 7% ROI. This suggests that DOE's projected higher desulfurization cost for challenged refineries is due primarily to higher capital costs and operating costs may actually be lower. This suggests that for ROI's below 10%, the difference in costs for average and challenged refineries is small. However, since it appears that the cost for average refineries included some unnecessary costs, the actual cost difference for average and challenged refineries may be larger than indicated in Table V-42.

c. Cost of Meeting a 5 ppm Averaging Standard

We received comments from the automobile industry that we should finalize our gasoline sulfur program with a 5 ppm average sulfur standard. We analyzed the cost of meeting that standard. We contacted CDTech and Mobil Oil and obtained input and process information on how their processes could be used by refiners to desulfurize their FCC naphtha to 5 ppm. The CDTech unit which was costed out above to desulfurize the FCC naphtha to below 100 ppm for a pool average of 30 ppm, can be modified to desulfurize FCC naphtha to 5 ppm. The CDTech unit normally is comprised of two columns, one is the CDHydro column, and the second is named CDHDS. To attain very low sulfur FCC naphtha, CDTech informed us that they could use two of their CDHDS columns to attain FCC desulfurization beyond 99 percent. Similar to the use of CDTech process for treating gasoline down to 30 ppm, the CDHydro unit is commercially demonstrated, but the CDHDS unit is not.

Mobil Oil has commercial desulfurization experience with their Octgain 125 process desulfurizing the FCC naphtha by over 99 percent. However, because of the amount of olefin desulfurization and octane loss by the Mobil process, if it were used to desulfurize light FCC naphtha, Mobil Oil recommends that their process be coupled with an less aggressive hydrotreating process for treating the light FCC naphtha to reduce octane loss. We considered using an extractive desulfurization unit, or CDTech's CDHydro process. The CDHydro process has two advantages over the extractive desulfurization unit. First, it removes more sulfur out of the light FCC naphtha pool. Second it is a desulfurization unit coupled with a distillation column, saving the need for a separate splitting column. Therefore, we coupled CDTech's CDHydro process with Octgain's 125 process to most cost-effectively desulfurize the FCC naphtha, both of which are commercially demonstrated.

Finally, other desulfurization technologies which can be used to desulfurize gasoline to 5 ppm is the combination of an FCC feed hydrotreater with a CDTech unit, or any other FCC gasoline hydrotreater. In this case, the FCC feed hydrotreater is commercially demonstrated, but the CDTech unit has not yet been demonstrated. This strategy is particularly likely for refineries which already have an FCC feed hydrotreater.

The process operation information for these processes is summarized in Table V-43. The processing costs for the CDTech unit presented here are greater than those presented in Table V-24 above, due to the need to achieve a greater degree of desulfurization.

Table V-43. Process Operation Information for Deep Desulfurization of FCC Naphtha

Technology *(sulfur removal efficiency)*	*CDTech* *(99.4%)*	*CDHydro* *(98%)*	*Octgain 125* *(99.9%)*	*FCC Feed Hydrotreater* *(93%)*
Capacity (MMbbl/day)	20,000	8800	8000	34,500
Capital Cost (MM$)	25.7	4.6	14.5	60
Hydrogen Consumption (SCF/bbl)	165	30	420	290
Electricity (KwH/bbl)	0.75	0.5	2.3	1.5
HP Steam (Lb/bbl)	-	-	-	14
Fuel Gas (BTU/bbl)	81,240	55,000	51,000	56,000
Catalyst Cost ($/bbl)	0.23	0.02	0.50	0.04
Cooling Water (Gal/bbl)	83	60	45	-
Yield Loss (%)	0	0	8.5	0.9
Octane Loss (R+M)/2	2.1	0	0	-

Meeting a 5 ppm specification day-in and day-out would require refiners to ensure that each and every stream is low in sulfur. Thus, gasoline blendstocks which are sufficiently low in sulfur for meeting a 30 ppm specification may have to be monitored more closely and the sulfur level would, perhaps, have to be controlled tighter than what they are now. These streams include reformate, isomerate, alkylate, hydrocrackate, and even MTBE. Since these streams are already low in sulfur (10 ppm or lower except for MTBE which can be two to three times that) not much monitoring or treating is necessary to ensure that these streams remain low in sulfur, and the cost is expected to be low. We did not provide our own estimates of these costs; instead we used the costs from the Alliance of Automobile Manufacturer's study by Mathpro on the cost of meeting a 5 ppm gasoline sulfur specification. These monitoring or sulfur controlling strategies and their respective costs are summarized below in Table V-44. In sum, accounting for these refinery processing changes add an additional 0.2 cents per gallon to the cost of producing gasoline.

Table V-44. Other Refinery Process Changes Potentially Needed to Meet a 5 ppm Sulfur Standard *($1997)*

Description	*Unit Cost*	*Cost Impact on Gasoline Pool*
Install extractive desulfurization treating for captive MTBE	see extractive desulfurization costs	0.008
Install extractive desulfurization treating for light straight run and natural gasoline	see extractive desulfurization costs	0.03
Provide additional hydrotreating of hydrocrackate for recombinant mercaptans	$400/bbl/day + extractive desulfurization oper costs	0.04
Add three stage washing facilities for alkylate production	$200/bbl/day + extractive desulfurization oper cost	0.09
Apply good refinery practice to control reformate sulfur to <=1 ppm	$500/day	0.02

In addition to the information summarized above, we make additional assumptions with respect to estimating the cost of producing 5 ppm gasoline. To simplify the analysis, we created a national average refinery based on the individual PADD-average refineries, by volume weighting those average refineries. We volume-weighted the utility and other operational costs for the national average refinery. Like the analysis for the 30 ppm standard, we applied a 15 percent contingency factor to the final estimated cost of meeting the 5 ppm standard. We adjusted the capital capacity upward by 10 percent to account for the uncertainty of meeting the 5 ppm standard, and this is additional to the 7 percent factor to adjust calendar day throughput to stream day throughput. We added the tankage allowance like the 30 ppm analysis.

Based on the information summarized above, we estimated the cost of desulfurizing gasoline to 5 ppm. We included the 0.2 c/gal treatment costs for the other gasoline blendstocks in our cost calculation. Our cost estimate, however, does not include any additional distribution costs which may be incurred by distributing a much cleaner product. Our costs of achieving 5 ppm are summarized in Table V-45.

Table V-45. Estimated Cost of Meeting a 5 ppm Sulfur Standard
($1997)

Technology	Cost (c/gal)	Incremental Cost to 30 ppm Standard (c/gal)
CDTech	3.1	1.4
CDHydro/Octgain 125	3.4	1.7
FCC Feed HT/CDTech	3.8	2.1

The American Automobile Alliance funded a study by Mathpro to estimate the cost of producing 5 ppm sulfur gasoline.[25] The study is based on the same two of three desulfurization technologies which we used in our cost study, which is CDTech by itself or Octgain 125 coupled with CDHydro. The study estimated a cost of 2.0 and 2.5 c/gal incremental to 30 ppm gasoline, which Mathpro estimated to be 2.5 c/gal. Thus, the study's total estimated cost of meeting a 5 ppm sulfur standard is 4.5 to 5.0 c/gal.

The Alliance's cost study estimated a higher desulfurization cost than our study which is explainable by two primary differences. One, Mathpro, applied a very large 1.8 inside battery limit (ISBL) to outside battery limit (OSBL) capital cost adjustment factor, which is two times larger than typical. Second, the study amortized the capital costs on a 10 percent ROI. Amortizing the capital costs at a 7 percent ROI before taxes and using our ISBL to OSBL cost adjustment factor yields a cost which is essentially the same as ours.

4. Other Effects of This Program

a. Effect of the Cap Standard

In addition to the 30 ppm averaging standard, we are finalizing an 80 ppm per-gallon standard. This additional standard will help to avoid high sulfur batches of gasoline from causing reversibility problems with the emission control hardware. The per-gallon standard or cap on sulfur level provides an additional challenge to refiners by preventing them from producing moderate or high sulfur batches of gasoline, which could be possible while meeting the 30 ppm average standard.

There are a number of situations when refineries tend to produce batches of gasoline with high sulfur levels. The most obvious situation is when the refinery is experiencing problems with the added desulfurization unit, or problems with other units within the refinery responsible for, or associated with, desulfurizing gasoline blendstocks. However, changes in other refinery operations or other factors can also result in varying amounts of sulfur in gasoline. These include changes in feedstock qualities, changes in products produced, changes in throughput, process fluctuations, and changes in hardware processing efficiency caused by breakdown in equipment or catalyst inactivation.

In the Draft RIA for the NPRM, we laid out our premise that the cost of meeting the cap standard could be estimated by estimating the cost of reducing gasoline sulfur to meet the average sulfur level which refiners would be producing their gasoline at under the cap. This is based on a past communication with API on how to estimate the cost of the cap standard.[26] Since the averaging standard is at or below the average sulfur level which we expect refiners to operate at if only a 80 ppm cap standard applied, we assumed that there would be no new cost accrued by the cap standard. Upon investigating this further, we believe that situations could occur when a refiner could produce gasoline above an 80 ppm cap while still meeting a 30 ppm average standard. For example, if a refiner typically produced 25 ppm sulfur gasoline to meet this program's sulfur requirement, he could produce gasoline with 400-500 ppm sulfur for 3-4 days or 200-300 ppm gasoline for 4-6 days and still average 30 ppm for the calendar year. For example, these periods of producing high sulfur gasoline could occur if a refiner had to perform a turnaround of his FCC naphtha hydrotreater.

We received a couple of comments from refiners on our approach on not estimating a separate cost for the cap standard. These refiners said that they would accrue additional costs for the cap standard, especially during turnarounds, and that EPA should include these costs. The comments point out that refiners will overbuild on hydrotreating capacity to treat the high sulfur FCC naphtha which will need to be treated due to turnarounds of the desulfurization equipment.

Based on these comments, we modified the costs described above for producing low sulfur gasoline to account for those situations when refiners would otherwise produce high sulfur gasoline. There were four aspects to these modifications. First, we believe that refiners could store FCC naphtha during a shutdown of the FCC naphtha hydrotreater. Gasoline production would decrease in the short term, but gasoline meeting applicable commercial and regulatory specifications could still be produced and the rest of the refinery could remain operative. To facilitate this, we provided for the installation of a tank that would store 10 days of FCC naphtha production. This amount of storage should be adequate for most unanticipated turnarounds. We presumed that half of refiners would need to add such storage, the other half of refineries either already having such storage available, or have the capability to send the untreated blendstock to a nearby refinery which had spare capacity for treating this high sulfur blendstock. Second, we assumed that refineries would design and operate their desulfurization units to normally produce gasoline with 25 ppm sulfur. This would allow them to blend in some higher sulfur blendstock directly into their gasoline pool. Third, we assumed that refiners would install 5 percent more desulfurization capacity than necessary, in order to treat the blendstock which had been stored during a turnaround. We did this for all refiners, though it is possible that only one refiner out of a number of geographically grouped refiners might actually need to invest in extra capacity.

Finally, we include a 15 percent capital cost contingency factor, and a 10 percent operational cost contingency factor to account for costs related to the FCC naphtha hydrotreater and other units in the refinery which may not have been accounted for in the licensor estimates.

We believe that refinery managers will have to place a greater emphasis on the proper operation of all of their desulfurization units, not just the new FCC gasoline desulfurization unit, in order to consistently deliver low sulfur gasoline. This improved operations management could involve enhancements to the computer systems which control the refinery operations, as well as improved maintenance practices.[27] 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 above for FCC gasoline desulfurization.[28] [29]

Refiners will also likely invest in a gasoline sulfur analyzer.[30] The availability of a sulfur analyzer at the refinery would provide essentially 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 cost for a gasoline sulfur analyzer would be about $50,000, and the installation cost would be another $5000.[31] Compared to the capital and operating cost of desulfurizing gasoline, the cost for this instrumentation is far below 1 percent of the total cost of this program.

b. Other Effects on the Refining Industry

If a gasoline sulfur program is finalized, oil companies are expected to take a number of steps to maximize their profitability in the period after the program is implemented. First, and foremost refiners will try to minimize their costs by investing in the most cost-effective refinery changes. Despite frugal choices, almost every refiner will face capital and increased operating costs, and the refiner will try to pay off those costs. The most obvious step to recover those costs would be to increase the price of gasoline. However, in a competitive market, the effect of an increase in refiners' cost on the price of gasoline depends on both the market supply and demand. If market demand is "inelastic" (not sensitive to changes in price), then one would expect the price of gasoline to rise by the full amount of the cost increase, and refiners would recover all their operating cost and incrementally recover their capital costs. Since gasoline demand is not perfectly inelastic, some reduction in the quantity of gasoline demanded would be expected due to the price increase in gasoline. This would mitigate the increase in the price of gasoline, which would erode refiners' ability to recover their costs. In addition, changes in supply due to imports from abroad would change the supply curve which would also affect refiners' cost recovery; increased imports reduce domestic refinery cost recovery, while decreased imports increase cost recovery.

Overall, the U.S. refining industry is currently producing gasoline and other refined products at full capacity.[32] This situation, coupled with ever increasing demand for gasoline, would generally produce reasonable refining margins. However, increasing imports of gasoline over the past few years appears to be keeping prices lower, as refining margins have been relatively low on average over the past three to four years.

Both Canada and Europe are major exporters of gasoline and other refined products into the U.S. market. Stringent sulfur requirements in Europe, and similar proposed requirements in Canada, will phase-in about the same time as the proposed U.S. standards would phase in. These required improvements in fuel quality will increase costs in these areas, as well as in the U.S. This will support an increase in the price of gasoline in the U.S. sufficient to cover capital, as well as operating costs.

A significant amount of gasoline is also imported into the U.S. from the Middle East and South America. We do not expect gasoline sulfur standards to take effect in these gasoline exporting countries in the near future. Thus, refiners in these countries could reblend their gasoline to be able to export very low sulfur gasoline to the U.S., while selling higher sulfur gasoline elsewhere. Under this scenario, their costs could be significantly less than those of domestic refiners who essentially have to desulfurize their entire product. However, the potential volume of low sulfur gasoline would be limited. Also, these refiners also export to eastern Canada, which will have its own low sulfur specification. Thus, the ability of these importers to flood the market with inexpensive, low sulfur gasoline appears to be limited.

While margins may improve which would help domestic refiners recover the cost of meeting the proposed gasoline sulfur requirements, there are still differences between refiners which would cause the per-gallon cost for some to be higher than others. This may be due to: having to pay a premium for capital costs due to their location, starting from a higher sulfur baseline, or facing diseconomies of scale due to small size. In order to remain profitable, high cost refiners would be expected to take further steps to reduce their costs.

Refiners could adopt a whole array of changes which may help them meet the sulfur standard, at a reduced overall cost. These changes include changing crude oil supply, optimizing other feedstock use, cost cutting of existing operations, opting to use processing outside the refinery, improvements in transportation and marketing of product, and changing the consumer market.[33] Refiners could choose to merge their refining operations with other refiners. Merging of refinery downstream operations (the refining and marketing portions of the oil industry) is already occurring across the industry as a means to reduce administrative costs and optimizing the production and distribution of common products.[34] This practice has already been occurring because the return on investment for the refining portion of the industry has been low for some time.

It is possible that the projected per-gallon cost for a specific refinery to desulfurize gasoline may be high enough relative to their ability to pay that a refiner might conclude that it is in their best financial interest to sell the refinery. Over the last several decades, there have been numerous refinery sales as refiners have determined that they are no longer capable of making an acceptable level of profit, and, thus, have put the refinery up for sale.[35] Many of the refineries sold have been purchased by independents (refiners who are not vertically integrated). Because of their flexibility and the relative availability of crude oil and other feedstocks, such as residual oil, these independents have been able to profitably operate these refineries. If a buyer is not found, refiners might be compelled to close the refinery, if no provisions were available to prevent such closures.

However, the final rule contains a number of provisions which are intended to prevent refinery closures due to financial hardship. The small refiner provisions are projected to give 16 small refineries which are owned by small businesses until 2008 in order to meet the 30 and 80 ppm standards. Between 2004 and 2008, these refiners have to meet interim standards which are related to their current sulfur levels. The geographic phase in delays the 30 and 80 ppm standards until 2007 for 14 refiners located in PADD 4, but will also benefit those refiners located outside of PADD 4 but who sell a significant amount of gasoline in PADD 4. Finally, this final rule also includes a hardship provision applicable to up to about 1 percent of U. S. gasoline production. This provision is intended to benefit refiners who are not able to produce complying gasoline because of extreme and unusual circumstances outside the refiner's control that could not have been avoided through the exercise of due diligence. In all three of these cases, the additional time provided to meet the 30 and 80 ppm standards would allow these refiners to improve their financial standing, obtain a loan or another financial source for their capital expenditures, and employ desulfurization technology developed later on or take advantages of improvements made with existing or emerging desulfurization technology. Other refiners not covered by these provisions may also be able to delay compliance with the 30 and 80 ppm standards until 2006 through the Averaging, Banking and Trading program (ABT). The ABT program allows a refiner to phase-in the gasoline sulfur program across its refineries to its best financial advantage, or gain even more leeway through the generation and purchase of sulfur credits. For the Final Rule, we are providing more flexibility to refiners by opening up the provisions governing the trading of allotments to allow trading among all refineries to meet the corporate sulfur standard.

We received several comments that we should do a refinery closure analysis. However, we feel that these provisions, which are all designed to minimize the impact of the sulfur standards on refiners, will address the concerns related to the issue of refinery closures. We can also point to Mathpro's refinery-by-refinery analysis for the Alliance which provides us with additonal assurance that refineries will not close.[36] Mathpro first analyzed the cost of the gasoline sulfur program on each refinery in PADD 4. Then it compared the cost to the cash operating margins of these refineries, and concluded that the relative cost is insufficient to cause refinery closures in PADD 4. After our own review of the work completed by Mathpro we reached the same conclusion as Mathpro.

c. Other Fuel Issues Which May Affect the Cost to Desulfurize Gasoline

We received several comments on our proposed rule that we should consider the impact of the expected phase-down of MTBE use in gasoline, and the potential reduction of diesel sulfur, in our cost analysis of desulfurizing gasoline. With respect to an expected phase-down of MTBE, we expect that the MTBE content in gasoline will be limited, but not phased out, which will still allow for the blending of a small volume of MTBE into gasoline. Thus some refiners which may not be using MTBE now may actually have more access to MTBE for blending into their gasoline, while other refiners which make a lot of RFG or oxyfuels, may have to reduce their MTBE use. For desulfurizing their gasoline, refiners can choose among a number of different desulfurization technologies which have varying impacts on gasoline octane levels. Since refiners can expect MTBE levels to be phased down, we believe refiners' technology choice for desulfurizing gasoline will include how an MTBE phase-down will affect their particular situation, and they will choose the gasoline desulfurization technology that will reduce their costs while meeting both requirements. Thus, despite not knowing what the final requirements will be of an MTBE phase-down program, we believe that the phase-down of MTBE will not have a significant impact on the costs of desulfurizing gasoline.

With respect to diesel desulfurization, we heard from a number of refiners that they can address both gasoline and diesel desulfurization most cost-effectively with separate hydrotreating units. The alternative to separate "end of the pipe" hydrotreaters, is to put in a FCC feed hydrotreater which would still require the two additional desulfurization units (although an existing diesel hydrotreater could suffice as the second unit). However, FCC feed hydrotreaters incurs high capital costs which is a significant disincentive to their use. Because refiners aim to minimize their costs, with a bias away from capital costs, we are convinced that treating the diesel and gasoline blendstocks separately will be the method of choice for the majority of refiners, which is corroborated by the comments we received from the oil industry, and this strategy ensures that the costs of the two programs will be separate. Since there are still overlapping elements to both programs, such as hydrogen supply, the costs of which can be reduced if refiners can plan to implement both programs together, refiners want to know what the eventual diesel program will be before building their gasoline desulfurization units. We are working to accommodate them with a proposed rule on desulfurizing diesel fuel soon after this final rule. In the diesel desulfurization rule, we will evaluate the impact of both programs on the refining industry.

5. Per Vehicle Life-Cycle Fuel Costs

The additional cost of low sulfur gasoline is encountered by the average vehicle owner each time the fuel tank is refilled. The impacts of the gasoline sulfur standard on the average vehicle owner can therefore be calculated as the increased fuel production costs in cents per gallon, multiplied by the total number of gallons used by a vehicle over a particular timeframe. Thus we have calculated the in-use impact of our gasoline sulfur standard on a per-vehicle basis for both a single year and for an entire vehicle's lifetime.

To estimate the cost of low sulfur gasoline in one year for a single vehicle, it is necessary to convert the annual miles traveled by a single vehicle into gallons of gasoline consumed. This conversion requires the use of an average fuel economy factor. Although the current fleet-average fuel economy is approximately 20.7 miles per gallon[37], this value is expected to change in the future for two reasons:

1) As the fleet turns over, those vehicles that were certified at lower fuel economy levels drop out of the in-use fleet.

2) The light-duty vehicle fraction of the fleet is projected to drop as more and more light-duty trucks come into the market.

We have projected that the light-duty vehicle portion of the fleet will level off to a fuel economy of about 24.2 miles per gallon during the next decade, while the light-duty truck portion of the fleet will level off to about 15.5 miles per gallon in the same timeframe[12]. Using the projected long-term distribution of 40 percent LDV and 60 percent LDT in the fleet[38], we calculated the fleet-average fuel economy to be 19.0 miles per gallon.

In a single year, the average in-use light-duty vehicle travels approximately 11,500 miles[13]. Applying the average fuel economy factor of 19.0 miles per gallon and the initial cost for low sulfur fuel of 1.93 ¢/gal leads us to a per-vehicle estimate of $11.68. This is the additional cost that the average vehicle owner will incur in the first year of the program due to the sole use of low sulfur gasoline.

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[12] In the NPRM, the value of 15.5 mpg was used for all light-duty trucks. For the final rulemaking, we have instead applied different mpg values to the different weight classes of trucks: LDT1, 18.7 mpg; LDT2, 15.7 mpg; LDT3, 13.2 mpg; LDT4, 12.2 mpg. Using the weighting factors in Table VI-4, the weighted average of these values remains 15.5 mpg.

[13] Calculated from the annual miles traveled per vehicle for each year of a vehicle's life, multiplied by a distribution of vehicle registrations by year. Annual miles travelled from "MOBILE6 Fleet Characterization Input Data," Tracie R. Jackson, Report Number M6.FLT.007. Estimate of 11,500 miles per year includes both LDV and LDT.

The per-vehicle cost of low sulfur gasoline can also be calculated over the lifetime of a vehicle. However, to calculate a lifetime cost for the average in-use vehicle, it is necessary to account for the fact that individual vehicles experience different lifetimes in terms of years that they remain operational. This distribution of lifetimes is the vehicle survival rate distribution, for which we used data from the National Highway Transportation Safety Administration. The costs of low sulfur gasoline incurred over the lifetime of the average fleet vehicle can then be calculated as the sum of the costs in individual years as shown in the equation below:

$$LFC = \sum [(AVMT)_i \bullet (SURVIVE)_i \bullet (C) \div (FE)]$$

Where:

LFC	= Lifetime fuel costs in $/vehicle
$(AVMT)_i$	= Annual vehicle miles travelled in year i of a vehicle's operational life[39]
$(SURVIVE)_i$	= Fraction of vehicles still operating after i years of service[40]
C	= Cost of low sulfur gasoline in $/gal
FE	= Fuel economy in miles per gallon. 24.2 for LDV, 15.5 average for LDT
i	= Vehicle years of operation, counting from 1 to 25

The cost of low sulfur gasoline is a function of the year of refinery production as described in Section V.B.; the initial cost of 1.93 ¢/gal applies only in the first year of low sulfur gasoline production. In subsequent years, costs will decrease as refiners make use of more advanced technology. As a result of these declining fuel costs over time, we determined that it is appropriate to calculate total lifetime costs for two separate cases:

1) Near-term, representing a vehicle whose operational life begins at the same time that low sulfur gasoline standards take effect (i.e., 2004)

2) Long-term, representing a vehicle whose operational life begins six years after low sulfur gasoline standards take effect (i.e., 2010)

The sixth year for calculating long-term costs of low sulfur gasoline was chosen to be consistent with the sixth year of vehicle manufacture, when the capital cost amortization period ends. Details of the calculation of long-term vehicle costs are given in Section V.A.

We used the above equation to calculate lifetime fuel costs separately for LDV, LDT1, LDT2, LDT3, and LDT4. The results are shown in Table V-46.

Table V-46. Undiscounted Per-vehicle Costs of Low Sulfur Gasoline

	Near-term ($)	*Long-term ($)*
LDV	95.03	89.45
LDT1	168.15	157.78
LDT2	200.27	187.93
LDT3	255.95	240.10
LDT4	276.93	259.78

We then weighted the per-vehicle costs for the individual vehicle categories in Table V-46 by the fleet fractions. As a result, the total cost incurred by the average in-use vehicle over its lifetime due to the use of low sulfur gasoline was calculated to be $164.83 on a near-term basis and $154.77 on a long-term basis.

An alternative approach to calculating lifetime per-vehicle costs of low sulfur gasoline is to discount future year costs. This approach leads to "net present value" lifetime fuel costs, and is a useful means for showing what the average vehicle owner would have to spend in the first year in order to pay for all future year fuel costs. It also provides a means for comparing the program's costs to its emission reductions in a cost-effectiveness analysis, as described in Section VI.

Discounted lifetime fuel costs are calculated in an analogous manner to the undiscounted values, except that each year of the summation is discounted at the average rate of 7%. The equation given above can be modified to include this annual discount factor:

$$\text{LFC} = \sum [\{(\text{AVMT})_i \bullet (\text{SURVIVE})_i \bullet (\text{C}) \div (\text{FE})\}/(1.07)^{i-1}]$$

Once again, we calculated lifetime fuel costs separately for LDV, LDT1, LDT2, LDT3, and LDT4. These values are shown in Table V-47.

Table V-47. Discounted Per-vehicle Costs of Low Sulfur Gasoline

	Near-term ($)	*Long-term ($)*
LDV	69.38	65.51
LDT1	119.60	112.65
LDT2	142.45	134.17
LDT3	181.21	170.55
LDT4	196.06	184.53

Once again, we then weighted the per-vehicle costs for the individual vehicle categories in Table V-47 by the fleet fractions. As a result, the total discounted cost incurred by the average in-use vehicle over its lifetime due to the use of low sulfur gasoline was calculated to be $117.82 on a near-term basis and $111.01 on a long-term basis.

A summary of all per-vehicle fuel costs described in this section is given in Table V-48 below.

Table V-48. Fleet Average Per-vehicle Costs Of Low Sulfur Gasoline

	Cost per vehicle ($)
First year	11.68
Lifetime, undiscounted, near-term	164.83
Lifetime, undiscounted, long-term	154.77
Lifetime, discounted, near-term	117.82
Lifetime, discounted, long-term	111.01

6. Aggregate Annual Fuel Costs

Aggregate fuel costs are those costs associated with the increased price per gallon of gasoline due to the proposed sulfur controls, multiplied by the total number of gallons of gasoline consumed in any given year by both highway and non-road sources. The total gallons of gasoline consumed by highway sources were calculated using the VMT projections used throughout the analyses within this document, along with projected fuel economy estimates (mpg) developed by Standard & Poor's Data Research International (DRI).[41] The resultant aggregate annual fuel costs are summarized in Table V-49. It is important to note that the capital costs associated with the proposed sulfur controls have been amortized for this analysis at a seven percent rate of return before taxes. The actual capital investment would occur up-front, prior to and during the initial years of the program, as described previously in this chapter.

Table V-49. Summary of the Increased Annualized Social Cost of Gasoline as a Result of the Tier 2 Gasoline Sulfur Controls ($Million)

Calendar Year	*Including Non-Road and Excluding California*[14]
2000	0
2004	1,618
2010	2,553
2015	2,648
2020	2,153

a. Methodology

The DRI develops projected fuel economy estimates for passenger cars (EPA's LDVs), light trucks under 10,000 pounds, and heavy trucks over 10,000 pounds. The VMT projections developed for EPA are for light-duty vehicles (LDV), light-duty trucks (LDT -- under 8500 pounds), and heavy-duty gasoline (over 8500 pounds). Because of the inconsistency in stratifying the fleet, the DRI fuel economy estimates for light trucks (under 10,000 pounds) were used for both the EPA LDT (under 8500 pound) and for EPA's heavy-duty gasoline trucks from 8500 to 10,000 pounds. The DRI fuel economy estimates for over 10,000 pound trucks were then used for EPA's over 10,000 pound heavy duty gasoline trucks.

The DRI fuel economy estimates also include both gasoline and diesel vehicles and trucks. As a result, the truck fuel economy estimates may be slightly higher than a gasoline-only estimate, as diesel vehicles and trucks tend to have higher fuel economy numbers than do gasoline vehicles and trucks. There should be little effect on the fuel economy estimates for

[14]The aggregate fuel costs used in the economic impact analysis include gasoline consumed by non-road sources and exclude gasoline consumed in the State of California.

passenger cars, because DRI estimates that 99.7 percent of passenger cars will be gasoline fueled in the 2000 calendar year (although 96.5 percent in the 2020 calendar year). Even for light trucks under 10,000 pounds, where more diesels would be expected, DRI estimates a split of 96 percent gasoline in the 2000 calendar year and 92.8 percent in the 2020 calendar year. Therefore, the effect of diesel vehicles and trucks on the DRI under 10,000 pound fuel economy estimates is considered negligible due to their low populations.

The effect of diesels on the over 10,000 pound heavy truck fuel economy estimates is also considered negligible, at least where the total gasoline consumption is concerned. Although the diesel population is relatively high in this category, where DRI estimates diesels at roughly 68 percent of the over 10,000 trucks, their effect is considered negligible because of the insignificant amount of gasoline consumed by trucks over 10,000 pounds (roughly 1 percent) relative to the gasoline consumed by vehicles and trucks under 10,000 pounds.

The motorcycle (MC) fuel economy value used is a very rough estimate (45 mpg), but the value chosen has little impact on this analysis given the relatively low VMT of motorcycles relative to LDVs and LDTs (<1 percent).

The stratification of EPA VMT projections between the 8500 to 10,000 pound trucks and the over 10,000 pound trucks was done by using draft MOBILE6 fleet characterization data which showed that approximately 83 percent of heavy-duty gasoline trucks are in the 8500 to 10,000 pound range with the remaining 17 percent in the >10,000 pound range.

The projected VMT values within each category (MC, LDV, LDT, HDG<10,000 pounds, and HDG>10,000 pounds) were then divided by the corresponding DRI projected fuel economy estimates (or the MC fuel economy estimate) to derive the gasoline consumption for each category per year. These values were then added, in each given year, to derive the total highway gasoline consumption for each year from 2004 to 2020.

b. Explanation of Results

The aggregate fuel costs used in the economic impact analysis include the non-road contribution but exclude gasoline consumed within the State of California. The total nationwide highway gasoline consumption was adjusted by eliminating 11 percent to exclude the California contribution.[15] The non-road contribution to the gasoline consumption was then added in by multiplying the highway contribution by 6.4 percent, as non-road sources are estimated to use 6.4 percent of the amount consumed by highway sources.[42] The highway gasoline consumption, including the non-road contribution and excluding the California contribution, was then

[15]Based on EPA VMT estimates that California accounts for approximately 11 percent of nationwide VMT.

multiplied by the per gallon increase due to the proposed sulfur control requirements to arrive at the estimated aggregate fuel cost for each individual year. The results are shown in Table V-50.

The aggregate fuel costs used in the economic impact analysis include non-road sources because gasoline used to power these sources will incur the increased per gallon cost, but exclude California because this rule will not impact the cost of gasoline in the State of California. The aggregate fuel costs used in the economic impact analysis include Alaska and Hawaii as gasoline in those states will incur an increased cost due to this rule.

The aggregate annual fuel costs change as projected per gallon costs and annual fuel consumption change over time. For information on how the per gallon costs change over time, see the discussion earlier in this Chapter. As a result of these changes, the aggregate annual fuel costs increase in later years due both to the reinvestment in refinery equipment (increased capital costs), which increases the per gallon cost, and because VMT is projected to increase every year, which results in increasing fuel consumption.

Table V-50. Calculation of Gasoline Consumption by Highway Sources

	Motorcycle				PassCar				LDT<8500				HDG 8500-10k					HDG>10k			Totals	
CY	AMD Gasoline MC VMT ex CA,AL,HI Bmiles (1)	Gasoline MC VMT nation Bmiles (2)	Esti-mated MC mpg	MC Gasoline Consump nation Bgal	AMD Gasoline PassCar VMT ex CA,AK,HI Bmiles (1)	Gasoline PassCar VMT nation Bmiles (2)	S&P DRI PassCar mpg (3)	PassCar Gasoline Consump nation Bgal	AMD LDT VMT ex CA,AL,HI Bmiles (1)	LDT Gasoline VMT nation Bmiles (2)	S&P DRI <10k Truck mpg (3)	LDT <8500 Gasoline Consump nation Bgal	AMD HDG VMT ex CA,AL,HI Bmiles (1)	HDG VMT nation Bmiles (2)	8500-10k HDG VMT nation Bmiles (4)	S&P DRI <10k Truck mpg (3)	8500-10k Gasoline Consump nation Bgal	>10k HDG VMT nation Bmiles (4)	S&P DRI >10k mpg (3)	>10k Gasoline Consump nation Bgal	EPA Total Hwy Gasoline Consump nation Bgal	S&PDRI Hwy Gasoline Consump nation Bgal (5)
1996	9				1272				711				46									120.94
2000	10	12	45	0.26	1204	1368	21.2	64.51	961	1092	15.9	68.66	54	61	51	15.9	3.18	10	7.1	1.46	138.07	132.72
2001	10	12	45	0.26	1186	1348	21.3	63.30	1023	1163	16.0	72.67	55	63	52	16.0	3.27	11	7.1	1.50	141.00	134.90
2002	11	12	45	0.27	1169	1329	21.4	61.96	1086	1234	16.1	76.44	57	65	54	16.1	3.35	11	7.2	1.55	143.56	137.07
2003	11	13	45	0.28	1152	1309	21.6	60.63	1148	1304	16.3	80.14	59	67	56	16.3	3.43	11	7.2	1.59	146.07	139.25
2004	12	13	45	0.29	1135	1290	21.7	59.33	1210	1375	16.4	83.78	61	69	58	16.4	3.50	12	7.2	1.63	148.54	141.43
2005	12	13	45	0.30	1118	1271	21.9	58.02	1273	1446	16.5	87.65	63	71	59	16.5	3.59	12	7.4	1.64	151.20	142.44
2006	12	14	45	0.31	1101	1251	22.0	56.75	1335	1517	16.6	91.18	65	74	61	16.6	3.67	13	7.4	1.68	153.59	144.62
2007	13	14	45	0.32	1084	1232	22.2	55.49	1398	1588	16.8	94.66	67	76	63	16.8	3.74	13	7.5	1.72	155.93	146.79
2008	13	15	45	0.33	1086	1234	22.3	55.25	1439	1635	16.9	96.64	69	78	65	16.9	3.82	13	7.5	1.77	157.80	148.97
2009	13	15	45	0.34	1089	1237	22.5	55.00	1480	1681	17.1	98.58	71	80	67	17.1	3.90	14	7.5	1.81	159.63	151.15
2010	14	16	45	0.35	1091	1240	23.2	53.44	1521	1728	17.3	99.88	73	82	68	17.3	3.95	14	7.5	1.87	159.48	151.56
2011	14	16	45	0.36	1093	1242	23.4	53.02	1562	1774	17.5	101.66	75	85	70	17.5	4.03	14	7.5	1.92	160.97	152.47
2012	14	16	45	0.37	1096	1245	23.7	52.61	1603	1821	17.6	103.39	77	87	72	17.6	4.10	15	7.5	1.96	162.43	153.38
2013	15	17	45	0.37	1098	1248	23.9	52.21	1644	1868	17.8	105.09	79	89	74	17.8	4.17	15	7.6	2.01	163.85	154.29
2014	15	17	45	0.38	1100	1250	24.1	51.82	1685	1914	17.9	106.75	81	91	76	17.9	4.23	16	7.6	2.05	165.25	155.20
2015	16	18	45	0.39	1103	1253	24.6	50.94	1726	1961	18.2	107.74	83	94	78	18.2	4.28	16	7.6	2.10	165.44	157.48
2016	16	18	45	0.40	1105	1256	24.8	50.57	1767	2007	18.4	109.31	85	96	80	18.4	4.34	16	7.6	2.14	166.77	158.39
2017	16	19	45	0.41	1107	1258	25.1	50.20	1808	2054	18.5	110.85	87	98	82	18.5	4.40	17	7.6	2.19	168.06	159.30
2018	17	19	45	0.42	1110	1261	25.3	49.85	1849	2101	18.7	112.36	89	101	83	18.7	4.46	17	7.7	2.23	169.33	160.21
2019	17	19	45	0.43	1112	1264	25.5	49.50	1890	2147	18.9	113.83	91	103	85	18.9	4.52	18	7.7	2.28	170.56	161.12
2020	17	20	45	0.44	1114	1266	25.5	49.66	1931	2194	19.0	115.46	93	105	87	19.0	4.59	18	7.8	2.29	172.45	161.66
2021	18	20	45	0.45	1117	1269	25.5	49.76	1972	2240	19.0	117.92	95	107	89	19.0	4.69	18	7.8	2.34	175.16	162.63
2022	18	21	45	0.46	1119	1272	25.5	49.87	2013	2287	19.0	120.37	97	110	91	19.0	4.79	19	7.8	2.39	177.88	163.60
2023	19	21	45	0.47	1121	1274	25.5	49.97	2054	2334	19.0	122.82	99	112	93	19.0	4.89	19	7.8	2.44	180.59	164.57
2024	19	22	45	0.48	1124	1277	25.5	50.08	2095	2380	19.0	125.27	101	114	95	19.0	4.99	19	7.8	2.49	183.31	165.54
2025	19	22	45	0.49	1126	1280	25.5	50.18	2136	2427	19.0	127.73	103	116	97	19.0	5.09	20	7.8	2.54	186.02	166.51
2026	20	22	45	0.50	1128	1282	25.5	50.28	2177	2473	19.0	130.18	105	119	99	19.0	5.19	20	7.8	2.59	188.74	167.48
2027	20	23	45	0.51	1131	1285	25.5	50.39	2218	2520	19.0	132.63	106	121	100	19.0	5.29	21	7.8	2.64	191.45	168.45
2028	21	23	45	0.52	1133	1288	25.5	50.49	2259	2567	19.0	135.08	108	123	102	19.0	5.38	21	7.8	2.69	194.17	169.42
2029	21	24	45	0.53	1135	1290	25.5	50.60	2300	2613	19.0	137.53	110	126	104	19.0	5.48	21	7.8	2.74	196.88	170.39
2030	21	24	45	0.54	1138	1293	25.5	50.70	2341	2660	19.0	139.99	112	128	106	19.0	5.58	22	7.8	2.79	199.60	171.36

(1) See Chapter III of this Tier 2 Final Rule RIA for a discussion of these VMT projections.

(2) CA = 11% of nation; CA,AK,HI= 12% of nation

(3) From S&P DRI World Energy Service U.S. Outlook, April 1998, Table 17 (mpg values include diesel), S&P does not provide mpg estimates for 2021-2030 so the 2020 estimate is assumed for those years

(4) Uses Draft MOBILE6 Fleet Characterization Data for MOBILE6; OMS/T.Jackson, March 1999; uses fleet mix projections where ~83% of HDG are 8500-10K and ~17% of HDG are >10K

(5) Presented for comparison only. Discrepancy in later years due mainly to OMS's larger LDT VMT share (67% of LD VMT) vs S&P (~53% of <10k VMT)

Table V-51. Aggregate Annualized Fuel Costs per Year from 2004 to 2030

CY	EPA Total Hwy Gasoline Consump nation Bgal	Increased Social Costs for Gasoline			
		Total Hwy Gasoline Consumption excluding CA Bgal (2)	Non-road Gasoline Consumption excluding CA Bgal (3)	% of Total that is 30/80 ppm Sulfur Gasoline Bgal (4)	Annual Tier2 Cost excluding CA & including NonRoad $B
2000	138.07	122.89	7.86	0	0
2001	141.00	125.49	8.03	0	0
2002	143.56	127.77	8.18	0	0
2003	146.07	130.00	8.32	0	0
2004	148.54	132.20	8.46	0.5947	1.618
2005	151.20	134.57	8.61	0.6744	1.819
2006	153.59	136.69	8.75	0.9253	2.268
2007	155.93	138.78	8.88	0.9253	2.302
2008	157.80	140.44	8.99	1.0000	2.526
2009	159.63	142.07	9.09	1.0000	2.555
2010	159.48	141.94	9.08	1.0000	2.553
2011	160.97	143.27	9.17	1.0000	2.577
2012	162.43	144.56	9.25	1.0000	2.600
2013	163.85	145.83	9.33	1.0000	2.623
2014	165.25	147.07	9.41	1.0000	2.645
2015	165.44	147.24	9.42	1.0000	2.648
2016	166.77	148.42	9.50	1.0000	2.670
2017	168.06	149.58	9.57	1.0000	2.690
2018	169.33	150.70	9.64	1.0000	2.711
2019	170.56	151.80	9.71	1.0000	2.161
2020	172.45	153.48	9.82	1.0000	2.153
2021	175.16	155.90	9.98	1.0000	2.133
2022	177.88	158.31	10.13	1.0000	2.166
2023	180.59	160.73	10.29	1.0000	2.200
2024	183.31	163.14	10.44	1.0000	2.233
2025	186.02	165.56	10.60	1.0000	2.266
2026	188.74	167.98	10.75	1.0000	2.299
2027	191.45	170.39	10.91	1.0000	2.332
2028	194.17	172.81	11.06	1.0000	2.365
2029	196.88	175.23	11.21	1.0000	2.398
2030	199.60	177.64	11.37	1.0000	2.431

(1) See Chapter V, section B of this Tier 2 Final Rule RIA for a discussion of these estimates.

(2) CA = 11% of total nation; CA,AK,HI = 12% of nation

(3) OMS/T.Sherwood; NonRoad fraction = 6.4%; see memo to Docket A-97-10, 2/19/99

(4) Represents the fraction of total consumption, exluding CA, that is 30 ppm average/80 ppm max sulfur gasoline.

C. Combined Vehicle and Fuel Costs

Sections A. and B. of this section provide detailed cost analyses for Tier 2 vehicles and low sulfur gasoline, respectively. The following sums the costs to consumers to provide total incremental costs of the Tier 2 program. The per vehicle costs are provided first, followed by the total annual nationwide costs.

1. Combined Costs Per Vehicle

Table V-52 provides a summation of our estimated incremental per vehicle costs, including increased costs for Tier 2 vehicles and for low sulfur gasoline over the life of the vehicles. We use the cost estimates for our cost-effectiveness analysis presented in the following Chapter. As described in the previous sections, we expect these costs to decrease over time as manufacturers make production improvements and recover fixed costs. Table V-52 provides estimates of near-term costs, which represent costs in the first years of the program, and long-term costs which account for the cost decreases.[16]

Table V-52. Total Incremental Per Vehicle Costs to Consumers Over the Life of a Tier 2 Vehicle

	LDV ($)	*LDT1 ($)*	*LDT2 ($)*	*LDT3 ($)*	*LDT4/MDPV ($)*
Near-term Costs					
Vehicle costs	82	74	130	249	273
Fuel costs*	69	120	143	181	196
Total	151	194	273	430	469
Long-term Costs					
Vehicle costs	53	49	101	203	223
Fuel costs*	66	113	134	171	185
Total	119	162	235	374	408

* Discounted lifetime fuel costs

[16] Includes estimated costs for OBD II and ORVR requirements for MDPVs.

2. Combined Total Annual Nationwide Costs

Figure V-2 and Table V-53 summarize EPA's estimates of total annual costs to the nation both for Tier 2 vehicles and low sulfur gasoline.[17] The capital costs have been amortized for these analyses. The actual capital investment would occur up-front, prior to and during the initial years of the program, as described previously in this chapter. The fuel costs shown are for all gasoline consumed nationwide, including both on-highway and nonroad. Annual aggregate vehicle costs change as Tier 2 vehicle sales are phased-in and projected per-vehicle costs and annual sales change over time. The aggregate fuel costs change as projected per gallon costs and annual fuel consumption change over time. The methodology we used to derive the aggregate costs are described in detail in the sections A.3. and B.5. of this chapter. As shown below, total annual costs increase over the phase-in period and peak at about $4.1 billion in 2009. Total annualized costs are projected to remain at about $4 billion through 2018. After 2018, annualized fuel costs are projected to decrease somewhat due to the use of new technologies which would enable refiners to produce low sulfur fuel at a lower cost. The gradual rise in costs long term is due to the effects of projected growth in vehicle sales and fuel consumption.

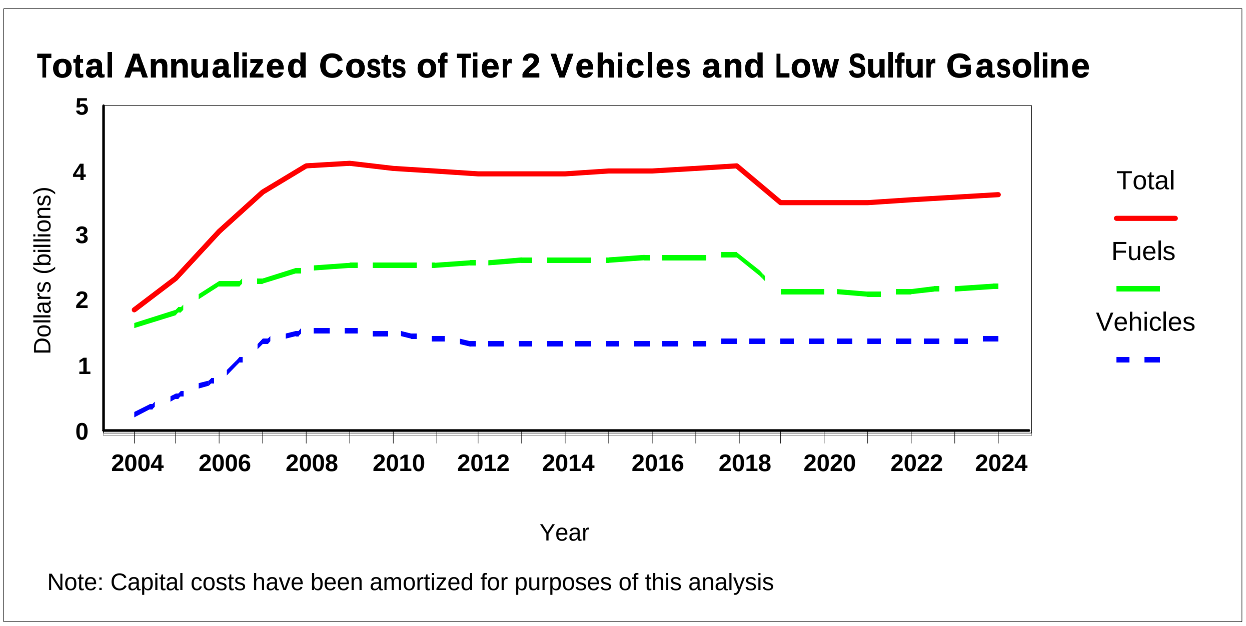

Figure V-2. Total Annualized Costs of Tier 2 Vehicles and Low Sulfur Gasoline.

[17] Excluding vehicles and fuel sold in California.

Table V-53. Total Annualized Costs to the Nation for Tier 2 Vehicles and Low Sulfur Gasoline ($million)

Calendar Year	*Vehicle Costs ($)*	*Fuel Costs ($)*	*Total ($)*
2004	$269	$1,618	$1,887
2005	$531	$1,819	$2,350
2006	$834	$2,268	$3,102
2007	$1,383	$2,302	$3,685
2008	$1,556	$2,526	$4,082
2009	$1,578	$2,555	$4,133
2010	$1,500	$2,553	$4,053
2011	$1,432	$2,577	$4,009
2012	$1,362	$2,600	$3,962
2013	$1,354	$2,623	$3,977
2014	$1,351	$2,645	$3,996
2015	$1,357	$2,648	$4,005
2016	$1,364	$2,670	$4,034
2017	$1,371	$2,690	$4,061
2018	$1,378	$2,711	$4,089
2019	$1,385	$2,161	$3,546
2020	$1,392	$2,153	$3,545
2021	$1,399	$2,133	$3,532
2022	$1,406	$2,166	$3,572
2023	$1,413	$2,200	$3,613
2024	$1,420	$2,233	$3,653

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