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. 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.[a] 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 discussions with manufacturers about trends in technology.

The following analysis projects a relatively uniform emission control strategy for various LDV and LDT models. However, this should not suggest that a single combination of technologies would be used by all manufacturers. Selecting technology packages requires extensive engineering judgement and EPA does not know future technology mixes and costs with certainty. 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

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[a] 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.

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 LDV and LDT certification levels also suggest this approach makes sense. We have made a best estimate of the combination of technologies that any manufacturer might use to meet the proposed standards at an acceptable cost and these technologies form the basis of the cost estimates. Since California, in their LEVII program, has adopted essentially the same standards and time-line that EPA is proposing, 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 analyses. Most manufacturer input is considered confidential business information and therefore is not described in detail.

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 0.156 g/mile. Vehicles have their emissions capped at 0.60 g/mile NOx and 0.23 g/mile NMHC. 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.

For the interim fleet average NOx standard, (average standard of 0.2 g/mile NOx with a NMHC standard of 0.156 g/mile), 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. We believe this approach is reasonable considering manufacturers are likely to avoid significant R&D efforts to meet a standard that is in effect for only a few model years. Essentially, a few such 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. For both phase-in periods (for LDVs, LDT1s, LDT2s, and for LDT3s, LDT4s), 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 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-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 and LDTs will be equipped with advanced catalysts. Catalyst manufacturers are currently working with engine manufacturers on new 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 $10.00 and $55.00 per vehicle. We derived the increased volume cost by taking the baseline cost of the catalyst per liter ($50/liter) and multiplying by the increase in catalyst volume. 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 cost of between $1.84 and $11.26 per vehicle. The details of the underfloor catalyst cost estimates are provided 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)
LDV	4-cylinder	2.0	1.8	2.0	10.00	0.000	0.000	0.085	0	0	1.84
	6-cylinder	3.2	2.8	3.2	20.00	0.000	0.000	0.138	0	0	2.95
	8-cylinder	4.5	4.0	4.5	25.00	0.000	0.000	0.194	0	0	4.14
LDT	4-cylinder	2.3	2.3	2.3	0.00	0.000	0.000	0.097	0	0	2.10
	6-cylinder	3.7	2.6	3.7	55.00	0.035	0.540	0.157	0.43	5.17	3.41
	8-cylinder	5.4	4.7	5.4	35.00	0.082	0.550	0.229	1.01	5.28	4.97

Precious Metal Costs

	$/troy ounce	$/gram
Pt	384	12.35
Pd	300	9.64
Rh	675	21.70

(a) Catalyst cost is $50/liter. Increased catalyst volume costs are the increase in catalyst volume multiplied by $50/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 and LDT4s, the use of close coupled catalysts is currently low relative to the other classes. For Tier 2 LDT3s and LDT4s, 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 $90 and $110, 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 that EPA believes will be used increasingly for 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. However, only some manufacturers believe the additional control is worth their higher incremental cost of 10 dollars. We believe more 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 air injection strategies for Tier 2 vehicles equipped with 6- and 8- cylinder engines. The air injection systems consist of an electric 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. Due to the relatively high cost of these improvements, we have projected manufacturers would use them only on LDTs, where it may be more difficult to meet the Tier 2 standards. In some cases, manufacturers may be able to use exhaust system improvements in lieu of adding close-coupled catalysts.

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 and LDT4s, 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 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 LDVs and LDTs 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-3 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 ($)*
4-cylinder	23.78	15.15	15.15	N/A	N/A
6-cylinder	62.85	85.45	94.97	235.32	N/A
8-cylinder	71.63	N/A	80.98	194.45	194.45
sales weighted	42.85	39.13	89.78	198.58	194.45

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	15	1.50	20.00	0	15	3.00	20.00	0	15	3.00
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	10.00	0	100	10.00	20.00	0	100	20.00	25.00	0	100	25.00
Increased catalyst loading (Rh)	1.84	0	100	1.84	2.95	0	100	2.95	4.14	0	100	4.14
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				23.78				62.85				71.63

(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 eight-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 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	15	1.50	20.00	0	15	3.00
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	100	1.00	4.00	0	100	4.00
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	55.00	0	100	55.00
Increased catalyst loading	1.84	0	100	1.84	2.95	0	100	2.95
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				15.15				85.45

(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 eight-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 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	15	1.50	20.00	0	15	3.00	20.00	0	15	3.00
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	100	1.00	4.00	0	100	4.00	6.00	0	100	6.00
Low thermal capacity manifold	20.00	25	50	5.00	40.00	25	50	10.00	40.00	25	50	10.00
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	55.00	0	100	55.00	35.00	0	100	35.00
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)	1.84	0	100	1.84	2.95	0	100	2.95	4.14	0	100	4.14
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				15.15				94.97				80.98

(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 eight-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 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 Tier 1 LDT3

	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	15	3.00	20.00	0	15	3.00
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	100	4.00	6.00	0	100	6.00
Leak-free exhaust system (e)	20.00	50	100	10.00	20.00	50	100	10.00
Low thermal capacity manifold	40.00	25	75	20.00	40.00	25	100	30.00
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	90.00	12	100	79.20	110.00	55	80	27.50
Dual underbody or main catalyst	160.00	0	0	0.00	160.00	40	40	0.00
Increased catalyst volume	55.00	0	100	55.00	35.00	0	100	35.00
Increased catalyst loading (Pt)	0.43	0	100	0.43	1.01	0	100	1.01
Increased catalyst loading (Pd)	5.17	0	100	5.17	5.28	0	100	5.28
Increased catalyst loading (Rh)	3.40	0	100	3.40	4.97	0	100	4.97
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				235.32				194.45

(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 eight-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 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 LDT4 Compared to Tier 1 LDT4

	8-Cylinder (100%)			
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)
Universal Exhaust Gas Oxygen Sensor (UEGO)	20.00	0	15	3.00
Air-assisted fuel injection (a)	16.00	0	50	8.00
Individual cylinder fuel control (b)	0.00	0	10	0.00
Retarded spark timing at start-up (b)	0.00	25	100	0.00
Improved precision fuel control (c)	0.00	50	100	0.00
Faster microprocessor	3.00	0	100	3.00
Fast light-off exhaust gas oxygen sensor (planar)	8.00	80	100	1.60
Heat optimized exhaust pipe (d)	6.00	0	100	6.00
Leak-free exhaust system (e)	20.00	50	100	10.00
Low thermal capacity manifold	40.00	25	100	30.00
Engine modifications (f)	15.00	0	100	15.00
Full electronic EGR	10.00	0	50	5.00
Close-coupled catalyst	55.00	0	0	0.00
Underbody or main catalyst	80.00	60	60	0.00
Dual close-coupled catalyst	110.00	55	80	27.50
Dual underbody or main catalyst	160.00	40	40	0.00
Increased catalyst volume	35.00	0	100	35.00
Increased catalyst loading (Pt)	1.01	0	100	1.01
Increased catalyst loading (Pd)	5.28	0	100	5.28
Increased catalyst loading (Rh)	4.97	0	100	4.97
Improved double layer washcoat + 600 cpsi cell density	6.59	0	100	6.59
Secondary air injection (g)	65.00	0	50	32.50
Total Incremental Cost				194.45

(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 eight-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 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 proposed 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 proposed 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 proposing. 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% 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 proposed 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 $2400 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 proposed evaporative standard for HLDTs (1.2 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 proportionately 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 proposed 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 reasearch 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 and LDT4s. 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.[b] 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 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.

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.

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

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. 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 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 ($)*
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 ($)*
Variable	46.10	42.38	93.03	201.83	197.70
Fixed	22.03	19.47	19.26	19.61	21.18
Total	68.13	61.85	112.29	221.44	218.88

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 consistently shown that as manufacturers gain experience in production, they are able to apply innovations to simplify machining and assembly operations, use lower cost materials, and reduce the number or complexity of component parts. These effects are often described as the manufacturing learning curve.[6]

The learning curve is a well documented and accepted 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 in 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. These 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.

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] As shown in Figure V-1, of the 108 progress ratios observed, eight were less than 70 percent, 39 were in the range of 71 to 80 percent, 54 were in the range of 81 to 90 percent, and seven were above 90 percent. The average progress ratio for the whole data set falls between 81 and 82 percent. The lowest progress ratio of 55 percent shows the biggest improvement, representing a remarkable 45 percent reduction in costs with every doubling of production volume. At the other extreme, 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. This data supports the commonly used p value of 80 percent, i.e., each doubling of cumulative production reduces the former cost level by 20 percent. 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.

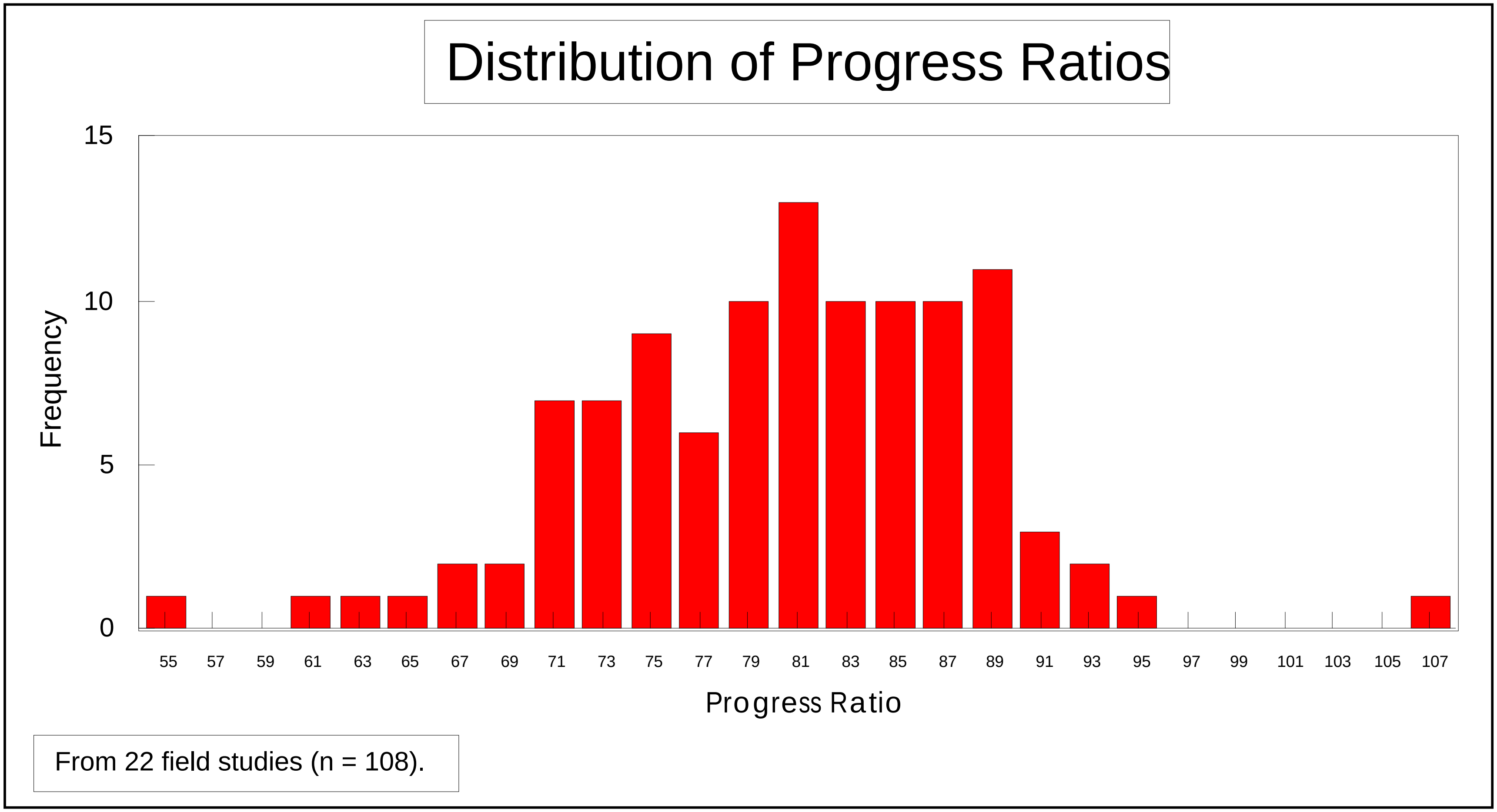

Figure V-1. Distribution of Progress Ratios

EPA applied a p value of 20 percent beginning in the third year of production in this analysis. That is, the variable costs were reduced by 20 percent for each doubling of cumulative production. To avoid overly optimistic projections, we included several additional constraints. Using one year as the base unit of production, the first doubling would occur at the start of the third model year of production. To be conservative, 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 and LDT4s than for LDVs.

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

Production Year	*LDV ($)*	*LDT1 ($)*	*LDT2 ($)*	*LDT3 ($)*	*LDT4 ($)*
1st and 2nd year	68.13	61.85	112.29	221.44	218.88
3rd year: learning curve applied	61.95	56.82	101.17	192.97	190.36
6th year: fixed costs expire	39.92	37.36	81.91	173.36	169.18

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 standards. Manufacturers will most likely meet the standards through improvements to existing technologies. We do not anticipate that the improvements to technologies will affect fuel economy or in-use maintenance. The costs of fuel quality improvements are provided in section B, below.

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, as well as the improved exhaust emissions control system.[c] 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 ($)*
1st and 2nd year	80.12	72.88	136.48	273.92	270.28
3rd year: learning curve applied	72.34	66.55	122.47	238.05	234.35
6th year: fixed costs expired	50.31	47.08	103.21	218.44	213.17

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 and LDTs. 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 $256 million in 2004 and peaking at $1,587 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 $1,346 million

[c] 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.

in 2014, after which the growth in vehicle population leads to increasing costs that reach $1,386 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	246,026	342,543	285,556	294,231
LDT1	0	96,101	70,113	72,243
LDT2	0	592,396	512,604	528,175
LDT3	10,507	373,188	329,438	339,445
LDT4	0	182,341	147,904	152,397
Total	256,533	1,586,569	1,345,614	1,386,491

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. 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.[11] 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.[12] 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	471	591	674	687	715
Total	13,234	13,636	13,911	14,192	14,769

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 25 percent of vehicles overall would fall into the highest bin (0.60 g/mile NOx), 30 percent in the next highest bin (0.3 g/mile NOx) and the remaining 45 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.

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* (%)*
2004	50	0	0	2	0
2005	100	0	0	7	0
2006	100	100	30	22	0
2007	100	100	100	55	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 and LDT4s, starting with LDT3s in 2008.

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 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 annual nationwide costs by vehicle class for years 2004 through 2020. Table V-21 presents these cost figures summed for all LDVs and LDTs.

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

Calendar Year	*Fixed Cost ($)*	*Variable Cost ($)*	*Total Cost ($)*
2004	64,020,172	182,006,058	246,026,230
2005	128,040,345	353,094,621	481,134,966
2006	128,040,345	319,146,974	447,187,318
2007	128,040,345	286,574,509	414,614,854
2008	128,040,345	276,809,911	404,850,256
2009	64,020,172	278,523,090	342,543,263
2010	0	279,915,706	279,915,706
2011	0	281,315,284	281,315,284
2012	0	282,721,861	282,721,861
2013	0	284,135,470	284,135,470
2014	0	285,556,147	285,556,147
2015	0	286,983,928	286,983,928
2016	0	288,418,848	288,418,848
2017	0	289,860,942	289,860,942
2018	0	291,310,247	291,310,247
2019	0	292,766,798	292,766,798
2020	0	294,230,632	294,230,632

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	72,431,363	100,146,547
2007	27,715,184	74,828,038	102,543,222
2008	27,715,184	68,098,756	95,813,941
2009	27,715,184	68,386,267	96,101,452
2010	27,715,184	68,728,199	96,443,383
2011	0	69,071,840	69,071,840
2012	0	69,417,199	69,417,199
2013	0	69,764,285	69,764,285
2014	0	70,113,106	70,113,106
2015	0	70,463,672	70,463,672
2016	0	70,815,990	70,815,990
2017	0	71,170,070	71,170,070
2018	0	71,525,920	71,525,920
2019	0	71,883,550	71,883,550
2020	0	72,242,968	72,242,968

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	159,053,529	186,778,683
2007	92,417,180	547,721,457	640,138,637
2008	92,417,180	545,161,597	637,578,777
2009	92,417,180	499,978,476	592,395,655
2010	92,417,180	502,478,368	594,895,548
2011	64,692,026	504,990,760	569,682,786
2012	0	507,515,714	507,515,714
2013	0	510,053,292	510,053,292
2014	0	512,603,559	512,603,559
2015	0	515,166,576	515,166,576
2016	0	517,742,409	517,742,409
2017	0	520,331,121	520,331,121
2018	0	522,932,777	522,932,777
2019	0	525,547,441	525,547,441
2020	0	528,175,178	528,175,178

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

Calendar Year	*Fixed Cost ($)*	*Variable Cost ($)*	*Total Cost ($)*
2004	869,782	9,636,772	10,506,553
2005	2,029,491	23,267,227	25,296,718
2006	6,378,400	74,126,448	80,504,848
2007	15,946,000	191,702,483	207,648,483
2008	28,992,728	359,149,330	388,142,058
2009	28,122,946	345,064,896	373,187,842
2010	26,963,237	322,930,549	349,893,785
2011	22,614,328	324,545,202	347,159,529
2012	13,046,727	326,167,928	339,214,655
2013	0	327,798,767	327,798,767
2014	0	329,437,761	329,437,761
2015	0	331,084,950	331,084,950
2016	0	332,740,375	332,740,375
2017	0	334,404,076	334,404,076
2018	0	336,076,097	336,076,097
2019	0	337,756,477	337,756,477
2020	0	339,445,260	339,445,260

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

Calendar Year	*Fixed Cost ($)*	*Variable Cost ($)*	*Total Cost ($)*
2004	0	0	0
2005	0	0	0
2006	0	0	0
2007	0	0	0
2008	4,819,090	57,785,178	62,604,267
2009	13,768,828	168,572,016	182,340,843
2010	13,768,828	160,863,474	174,632,302
2011	13,768,828	145,707,212	159,476,040
2012	13,768,828	146,435,748	160,204,576
2013	8,949,738	147,167,927	156,117,665
2014	0	147,903,766	147,903,766
2015	0	148,643,285	148,643,285
2016	0	149,386,502	149,386,502
2017	0	150,133,434	150,133,434
2018	0	150,884,101	150,884,101
2019	0	151,638,522	151,638,522
2020	0	152,396,714	152,396,714

Table V-21. Annual Nationwide Costs For Tier 2 LDVs and LDTs

Calendar Year	*Fixed Cost ($)*	*Variable Cost ($)*	*Total Cost ($)*
2004	64,889,954	191,642,830	256,532,784
2005	130,069,836	376,361,848	506,431,684
2006	189,859,083	624,758,314	814,617,397
2007	264,118,709	1,100,826,487	1,364,945,196
2008	281,984,526	1,307,004,772	1,588,989,298
2009	226,044,310	1,360,524,745	1,586,569,055
2010	160,864,429	1,334,916,295	1,495,780,724
2011	101,075,181	1,325,630,297	1,426,705,478
2012	26,815,555	1,332,258,449	1,359,074,004
2013	8,949,738	1,338,919,741	1,347,869,479
2014	0	1,345,614,340	1,345,614,340
2015	0	1,352,342,411	1,352,342,411
2016	0	1,359,104,123	1,359,104,123
2017	0	1,365,899,644	1,365,899,644
2018	0	1,372,729,142	1,372,729,142
2019	0	1,379,592,788	1,379,592,788
2020	0	1,386,490,752	1,386,490,752

B. Gasoline Desulfurization Costs

In this section, we will first lay out the methodology for our analysis of gasoline desulfurization costs. Then we will present the estimated cost of desulfurizing gasoline. Finally, we will discuss other relevant issues concerning the desulfurization of gasoline.

1. Methodology

The approach to estimating gasoline desulfurization costs is different from how we estimated costs in the Gasoline Sulfur Staff Paper. The costs presented in that report were developed using a refinery model run by the Oak Ridge National Laboratory (ORNL). Due to some improvement work which was being done with that refinery model, we were not able to develop costs for this analysis using that model. For this reason, we developed our own gasoline desulfurization model. For the Final Rule, we expect that the ORNL refinery model will be used to develop gasoline desulfurization costs and we will consider those costs as well as other costs from any other refinery modeling studies which may be performed by other studies.

The analysis was performed on a regional basis. The regions used are Petroleum Administrative Districts for Defense (PADDs). The analysis was conducted this way to take advantage of the PADD-level refinery information which is available for each PADD. This will help improve the understanding of how the cost for desulfurization will differ between these regions. Figure IV-2 above depicts the various PADDs of the country. As shown in the Figure, PADD 1 comprises the Northeast states, PADD 2 comprises the Midwest states, PADD 3 comprises the Gulf Coast states, PADD 4 comprises the Rocky Mountain states, and PADD 5 comprises the West Coast states. One issue to note is that PADD 5 normally includes California. However, since California already requires low sulfur gasoline as part of its California Phase II Reformulated Gasoline program, it would be inappropriate to include California in any part of this analysis. Thus, this analysis estimates the cost of desulfurizing gasoline in PADD 5 outside of California, which will be indicated as PADD 5OC from this point on.

The cost analysis for each PADD is performed for a single refinery which represents the average refinery characteristics for that PADD. Each PADD-average refinery is created by taking all the refining capacity and throughput in that PADD and averaging it over the number of refineries in that PADD.[d] The costs for the entire PADD can be calculated by simply multiplying the individual refinery cost by the number of refineries in that PADD. This analysis presumes that each refinery must install a desulfurization unit which slightly overestimates the capital cost, as some refineries already produce gasoline with less than or close to 30 ppm sulfur and they

[d] This methodology of modeling an average refinery, or a representation of the PADD-average, is the only practical method (since modeling every refinery would require proprietary information and substantial complexity) and the industry-accepted method for estimating fuel costs. This method, however, comes with the trade-off of only approximating the cost which would be developed if we were able to average and aggregate the results of modeling each and every refinery.

would meet the proposed sulfur standard without adding any gasoline desulfurization units.

Throughout most of this analysis, we presumed that the average refinery modeled will make their capital investments to meet a 30 ppm sulfur standard starting January 1, 2004. This investment scenario was assumed to simplify the analysis, however, it does not capture possible investment scenarios which could arise in response to refiners taking advantage of the proposed Averaging, Trading and Banking (ABT) program. Participating in the ABT program, refiners would choose a timeframe which best fits their company's financial situation, credit generation and banking capacity, and credit purchasing options, within the constraints of the per-gallon and corporate average sulfur standards. The net effect is that capital investments would likely be incurred over a six year period instead of all at once in 2003, which, if considered throughout this analysis, would have a small, decreasing effect on the costs estimated in the analysis. At the end of the analysis, we project the distribution of the capital costs over the years of the ABT program.

Each PADD was calibrated so that the volumes and sulfur levels for the various streams which contributed to the sulfur in the whole pool balanced with the sulfur level in the gasoline pool. The streams which contribute any significant amount of sulfur in the gasoline pool include the FCC gasoline, straight run (nonrefined crude oil in the gasoline boiling range), alkylate, and coker gasoline, if any was blended directly into gasoline (it may have been sent to other units such as the reformer, the alkylate plant, and the isomerate unit, which all desulfurize their feeds prior to processing). While alkylate sulfur levels can typically be equal to or less than five ppm, refineries which make alkylate from coker naphtha can have high levels of sulfur in alkylate (higher than 50 ppm). When these higher sulfur alkylate streams are averaged with the lower sulfur streams, the level of the average alkylate sulfur level will probably be high enough that we felt that it should be accounted for. The actual sulfur balance is described in detail further below.

This analysis does not directly estimate gasoline desulfurization costs for a portion of the industry affected. California refiners currently produce some non-California, low sulfur non-reformulated gasoline which is shipped outside of the state, yet this analysis did not attempt to estimate the cost to those refiners of desulfurizing that gasoline. Similarly, nondomestic refiners import some gasoline to the U.S., and these costs are not estimated as well. However, after estimating the average gasoline desulfurization cost for domestic refiners outside of California, the aggregate desulfurization cost is calculated by multiplying the domestic cost outside of California by a factor which accounts for the total number of gallons of gasoline sold in the U.S. outside of California. Thus, this analysis uses the estimated cost increase of gasoline produced by non-California U.S. refiners to represent the cost desulfurizing all gallons of gasoline consumed in the U.S.

The first step in desulfurization was presumed to be complete use of at least some of the existing desulfurization capacity available in the refinery. There are FCC feed hydrotreaters already present in many refineries which apparently are not being operated at capacity. The API/NPRA survey of 1997, which summarizes the operating characteristics and gasoline qualities of most of the U.S. refining industry, summarized the capacity and utilization of that capacity for FCC feed hydrotreaters for each PADD. Using that data, it was presumed that these units could be run at 100 percent of stream day capacity minus five percent which would allow for increased use which is expected to occur between now and when the gasoline sulfur program is proposed to begin. Thus, before calculating the size and costs associated with a FCC gasoline hydrotreater, the initial sulfur level in each PADD was adjusted to reflect the use of this capacity. The operating cost for running FCC feed hydrotreaters at capacity was based on data from operating costs data for a FCC hydrofiner. In some PADDs there was additional hydrocracker capacity as well. However, running these units at capacity was found to cost more per unit sulfur removed than putting in a Mobil Oil Octgain or a CDTECH unit. Thus, these units were presumed to not be operated at capacity. It should be noted that there are other hydrotreaters in refineries which perhaps could provide additional hydrotreating, either before additional hydrotreating capacity is installed, or to meet a low sulfur gasoline target. Feeds to the reformer, isomerate and alkylate units are almost always hydrotreated, and running these units at capacity could provide additional desulfurization with some operating cost, and perhaps some additional capital cost for debottlenecking. However, trying to estimate the cost and incremental desulfurization available from these units was not possible with the information we had available to us.

In most cases, cost estimation for desulfurization down to 30 ppm is made based on CDTECH and Mobil Oil's desulfurization technologies, which are improved FCC gasoline desulfurization technologies. For this analysis, we presume that half of the FCC gasoline hydrotreaters which would be installed are CDTECH units and the other half would be Mobil Oil Octgain units. Since past gasoline sulfur cost analyses were made based on Mobil Oil's Octgain 125 process (2nd generation Octgain), the cost of desulfurization of PADD 3 gasoline was also estimated with this process as well. This will allow us to compare the estimated desulfurization cost of newer desulfurization technologies with the technology previously relied upon in these other studies. Coker gasoline (that part of the coker stream in the gasoline boiling range which is blended directly into gasoline), if there was any, is assumed to be treated along with the FCC gasoline. Because maximum hydrotreating with the improved FCC gasoline desulfurization technologies did not reduce the gasoline sulfur levels in PADDs 4 and 5 down to 30 ppm, some straight run was presumed to be desulfurized as well. The process presumed to be used for that desulfurization is Merox. We obtained generic capital and operating cost data for adding a Merox unit.

The CDTECH costs for achieving the target sulfur level are based on the combined units of CDHydro and CDHDS. The minimum severity of these CDTECH units that would result in treating the entire FCC gasoline stream down to 30 ppm was presumed to be used, in lieu of more severely hydrotreating the heaviest fraction of the FCC gasoline stream. To allow us to estimate desulfurization at different severities, CDTECH provided us cost and unit operations data for a range in hydrotreating severities, from 50 percent to almost 98 percent, for their process.

Mobil Oil provided OCTGAIN 3 desulfurization cost data at one desulfurization severity. To estimate the desulfurization cost to reach 30 ppm, the fraction of FCC and coker gasoline to be desulfurized at that severity was determined. The Octgain unit was then sized to process that fraction. The sizing of the Octgain unit is consistent with how refiners are expected to use this technology, which is treat only the heavy FCC gasoline if this achieves the sulfur target. If not, then the heavy and medium FCC gasoline would be hydrotreated. Finally, only if this did not achieve the desired sulfur target, the entire FCC gasoline stream would be treated. In all cases, only one unit is used, but the unit is sized to treat the appropriate portion of the FCC gasoline pool until the target sulfur level is met. To facilitate this selective desulfurization strategy, a splitter (distillation column) may be needed between the FCC main fractionation tower and the OCTGAIN unit (however, if the entire FCC pool is being treated then a splitter may not be needed). We presume that half the refineries already have a splitter and are using it while the other half will have to install this splitter. Thus each PADD-average refinery has half the capital and operating cost of a full sized splitter. In cases of meeting a less stringent gasoline sulfur target where less than all the heavy FCC naphtha is being treated, the splitter is sized according to the volume of the FCC heavy naphtha being treated (if 60 percent of the FCC heavy naphtha must be treated to reach a particular sulfur reduction target, then only 60 percent of the FCC naphtha is routed to the splitter).

As stated above, cost estimation is based on vendor supplied operating and capital costs for CDTECH, OCTGAIN, FCC feed hydrotreating, and Merox units; while the ORNL refinery model is referenced for splitter operating and capital costs. Shell Oil (now Equilon) engineers analyzed the cost of installing a CDTECH unit into a generic refinery and compared their costs to those of CDTECH. This comparison is summarized below.

The cost of sulfur reduction was estimated for sulfur reductions down to PADD-average levels of 150, 100, 80, 40 and 30 ppm. The national cost of desulfurization is calculated by volume weighting the individual PADD costs. The costs are estimated for meeting the averaging standard, which is the cost estimation methodology recommended to us by the oil industry. Some additional cost may be incurred for meeting the cap standard, however, estimating these costs is more uncertain, so only the issues associated with meeting the cap standard are discussed. Therefore, no explicit costs of a cost over and above an averaging standard are developed.

a. Cost Inputs

Vendors for various desulfurization technologies were contacted to obtain detailed information on the raw material and utility needs and desulfurization capabilities for their technologies. This information is summarized below in Table V-22:

Table V-22. Raw Material and Utility Needs and Desulfurization Capabilities for Several Desulfurization Technologies

	FCC Feed Hydrotreating	*CDTECH* (96% desul)*	*Mobil Octgain 220† (95% desul)*	*Mobil Octgain 125 (98% desul)*	*Merox (60% desul)*
Feed (Bbls/Day)	-	40,000	25,000	8000	10,000
Capital Cost ($MM) ISBL	-	22.5	25	14.5	3.5
Six Tenths Rule Exponent	-	0.65	0.65	0.65	0.6
H2 Consumption (SCF/Bbl)	290	82	125	420	-
Electricity (KwH/Bbl)	1.5	0.5	1.1	2.3	-
HP Steam (Lbs/Bbl)	14	-	40	-	-
Fuel Gas (MBtu/Bbl)	56	55	12	51	-
Catalyst Cost ($/Bbl)	0.04	0.19	0.25	0.43	-
Cooling Water (Gals/Bbl)			220	45	
Octane Loss (R+M)/2	-	1.2	0.8	1.6	-
Yield Loss (vol.% gasoline) (vol.% LPG) (vol.% diesel) (vol.% resid)	 (6.5) (3.4) 2.2 3.1	 -	 0.7	 14	-
Operating Cost ($/Bbl)					0.06

* CDTECH provided data for desulfurization from 50 percent to 98 percent; only the data for 96 percent gasoline desulfurization is summarized here.

† Data was presented separately for light cat naphtha, medium cat naphtha, and heavy cat naphtha; however, in this table the data was volume-averaged together into one column for treating all three together.

I. Capital Cost

Capital costs are the one-time costs incurred by purchasing and installing new hardware in refineries. A number of factors are accounted for when estimating capital costs. The cost is calculated by first starting with the capital costs summarized in Table V-22 above. However, those capital costs are for the throughputs indicated, and must be adjusted to reflect throughputs different from that listed. The throughput normally listed for a new facility is the day to day throughput used to calculate operating cost, which is normally expressed as barrels of feed per calendar day. This throughput must be adjusted to estimate the capital cost based on stream days.[e] A calendar day to stream day factor is used to account for the difference between the throughput in calendar days versus the throughput in stream days. The ORNL refinery model provides calendar day to stream day inflation factors and the factor for the FCC unit, which is seven percent, is used here (the calendar day throughput is multiplied by 1.07 to estimate a stream day throughput). The factor for the FCC unit is used because these improved technologies are designed to operate with and be shutdown for maintenance on the same schedule as the FCC unit.

Also, a 15 percent design safety factor was applied to the capital cost. This means that facilities are sized 15 percent larger than what planned throughput would otherwise require.[13] This design factor, also sometimes called a contingency factor, is normally applied to cost estimates to account for uncertainties in the design. An additional five percent is added to the safety design factor, for a total of 20 percent, to account for the newness of these technologies.[14]

Once the stream day throughput is estimated, and the design factor is applied, if the recalculated throughput is different from the throughputs listed in the above table, the capital cost is estimated at this other throughput using an exponential equation termed the “six-tenths rule.”[15] 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 a splitter, 0.65 for OCTGAIN and CDTECH units, and 0.6 for a merox unit.

The capital costs are adjusted further to capture other cost factors which affect the ultimate cost of installing capital, and these factors vary by PADD. One of these factors adjusts

[e] The throughput in calendar days is simply the total throughput of a unit in a year divided by the number days in a year. The throughput in stream days is the total throughput of a unit in a year divided by the number of days which the unit is operating. The stream day daily throughput determines the necessary capacity of the unit since a unit must be able to handle that throughput on the days which the unit is operating.

the onsite costs upward to account for offsite costs.[f] According to Gary and Handwerk, the proportion of offsite cost to onsite cost varies depending on the crude oil throughput of the refinery. These varying factors are summarized in Table V-23.[16]

Table V-23. Offsite Factors for Different Sized Refineries

Refinery Size in Crude Oil Feed (BPSD)	*Offsite Costs, Percent of Inside Battery Limit Costs*
Less than 30,000	50
30,000 - 100,000	30
More than 100,000	20

Based on these offsite factors, because PADD 3 refineries average about 150,000 barrels per day, the representative refinery used in this analysis for that PADD was assigned an offsite factor of 1.2 (or a 20 percent increase). PADD 1, PADD 2, and PADD 5OC, refineries all average about 100,000 barrels of crude oil per day, so the representative refinery used in this analysis was assigned an offsite factor of 1.25. Finally, PADD 4 refineries average less than 30,000 barrels of crude oil per day, so the representative refinery for that PADD was assigned an offsite cost factor of 1.5. These factors are summarized in Table V-25 below.

Another factor which varies from PADD-to-PADD is the labor cost for installing the capital. Gary and Handwerk provide estimates for labor costs for a number of different cities, and these estimates are summarized in Table V-24, below.[17]

[f] When vendors normally report a capital cost, that cost includes what are called onsite costs for complete installation of the hardware, but excludes other costs integral for the functioning of the unit, and these other costs are called offsite costs. Onsite costs normally include the capital cost for the process unit, storage facilities, cooling water facilities, and steam facilities. Offsite costs normally include electric power distribution, any fuel gas facilities, water supply and treatment, plant air, fire protection, flare hookup, drain system, waste containment, plant communication, roads and walks, railroads, roads and walkways, fences and buildings. Thus offsite costs are other capital costs which will allow the facility to run as an integral unit within the refinery.

Table V-24. Labor Costs in Selected Cities

Location	*Relative Cost*
U.S. Gulf Coast	1.0
Los Angeles	1.4
Portland, Seattle	1.2
Chicago	1.3
St. Louis	1.4
Detroit	1.3
New York	1.7
Philadelphia	1.5
Alaska, North Slope	3.0
Alaska, Anchorage	2.0

Based on this information, each PADD was assigned a cost factor to account for the labor cost for installing capital. PADD 1 was assigned a value of 1.5 which corresponds with the factor for Philadelphia, where a number of PADD 1 refineries are located. PADD 2 was assigned a value of 1.3 which corresponded with Chicago and Detroit. PADD 3 was assigned a value of 1.0, which is accepted as the reference refinery-related labor cost for the country. PADD 4 was assigned a value of 1.4, which corresponds to the value of St. Louis, the closest city to PADD 4, and PADD 5 outside of California was assigned a value of 1.2, which corresponds with Portland and Seattle. These location factors are summarized below in Table V-25.

Table V-25. Capital Cost Factors Which Vary by PADD

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5 Outside CA*
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 capital costs which would be incurred by refiners in order to comply with the proposed sulfur standards must be amortized in order to combine this cost with recurring operating costs to produce a total per gallon cost in future years. In past analyses, EPA used a cost amortization factor of 0.173, which was based on a 10 percent return on investment (ROI), a 34 percent income tax rate, a 13 year economic and project life, and a 13 year depreciation life.

Regarding the 10 percent ROI, in 1997 we received comments from the automobile industry that the ROI for capital employed in the refining industry was less than 10 percent. They recommended use of an eight percent ROI, which we accepted and used to develop sulfur control costs in EPA's Staff Paper on Gasoline Sulfur Issues. The 1993 National Petroleum Study presented the actual ROI for the refining industry during the 1980's and early 1990's. ROI averaged close to eight percent during that timeframe. Since 1992, the refining industry has experienced a much lower ROI, averaging roughly three percent. However, these levels are clearly depressed and we do not believe that these low levels should be projected into the future. Thus, eight percent appears to be a reasonable level of ROI for assessing the impact of these regulations on the refining industry. However, in assessing the impact of these regulations on society, OMB Circular A-94 suggests that EPA use a seven percent discount factor in determining the net present value of both costs and benefits. Thus, a seven percent ROI will be used in determining the cost of reducing gasoline sulfur content for use in the cost effectiveness and cost benefit analyses. In assessing the impact of these regulations on the refining industry, the eight percent ROI will be used. Since the ROI of individual refiners can vary, we will also evaluate the impact of some variation around the average of eight percent ROI and use a range of six to 10 percent.

The 1993 National Petroleum Study also used slightly different estimates for the economic and depreciation life of capital and for the income tax rate than those cited above. In particular, the 1993 National Petroleum Study used an economic life of 15 years, a depreciation life of 10 years and an income tax rate of 39 percent.[18] Since the NPC study received a substantial amount of peer review, we decided to use these financial factors from that study, coupled with the above-mentioned estimates of ROI. The one exception is the elimination of the income tax from the assessment of societal costs. Since income taxes are simply transfer payments between various sectors of society, they are not included in societal costs. These factors and the resulting capital amortization factors are summarized in Table V-26 below.

Table V-26. Economic Cost Factors Used and the Resulting 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% 8% 10%	0.12 0.14 0.16

ii. Fixed Operating Costs

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.

Maintenance must be performed on all operating hardware to keep it in an operable condition, and when it is running, to keep the unit operating efficiently. 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. This factor is based on the maintenance factor used in the ORNL refinery model.

Other operating costs are accounted for as well in terms of generic cost factors which were taken 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 (which includes offsites, and the adjustment for location) 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.

iii. 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. These costs are summarized in Table # V-27 below.

Table V-27. 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
Diesel (c/Gal)	25.2	25.7	24.7	29.6	28.6
Residual Oil (c/Gal)	17.9	15.2	15.4	10.8	16.1
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.

Electricity is consumed in running pumps, air coolers, and other refinery equipment electrically powered. Electricity costs were taken from the EIA publication “Monthly Electric Utility Sales and Revenue Report with State Distributions.” The 1997 industrial electricity costs for individual states which comprise a PADD are averaged together to form a single individual PADD-wide cost.

Fuel gas is consumed in running furnaces for heating up streams including the reboilers used in distillation. Fuel gas cost is based on an estimation factor which is three dollars per million British thermal units (BTU) for PADD 3,[19] one quarter higher than that for PADDs 1, 2 and 5OC, and half higher for PADD 4. Steam demand is converted to BTU demand on the basis that it is 300 pound per square inch (psi) steam, and that demand is presumed to be met with fuel gas. Producing steam is presumed to demand 809 BTU per pound of steam required.

Cooling water is used for cooling streams, especially the vapor which comes off the top of a distillation column and must be condensed for recycling it back into the top of the distillation column. Cooling water is estimated to cost seven cents per 1000 gallons for PADD 3, seven and a half cents per gallon for PADDs 1, 2, and 5OC, and eight cents per gallon for PADD 4.[20]

Octane loss is caused by saturation of unsaturated compounds including olefins and aromatics which normally present in FCC gasoline. For each PADD, the cost of this loss is estimated by using the price differentials between premium and regular grades. The price differentials were based on the cost of gasoline grades sales to resale from the Petroleum Marketing Annual for 1997. Octane ((R+M)/2) spread, which is the octane difference between premium and regular grades, is from 1993 refining study by NPC.[21] According to DOE, octane spread has been increasing in recent years, so the cost for making up lost octane may be overestimated to some degree.

Yield loss is the loss of gasoline to lower boiling point petroleum compounds. It sometime occurs as gasoline is processed and tends to occur with hydrotreating. The conversion of gasoline to lower boiling point compounds incurs a cost because gasoline brings a higher profit than the other compounds. For this analysis, yield loss is presumed to occur by gasoline being converted to liquid petroleum gas (LPG).[22] Thus, yield loss is the resale price of gasoline minus the resale price of LPG. The costs of gasoline and LPG are from the Petroleum Supply Annual for 1997.

Finally, hydrogen costs also vary by PADD. The cost of hydrogen supply was estimated for PADD 3, and then increased for other PADDs that typically have higher costs. Hydrogen cost for PADD 3 is based on an average of refiners putting in their own hydrogen plants, which could cost as much as three dollars per thousand standard cubic foot (MSCF), and purchasing hydrogen as a commodity from a large hydrogen plant at a little more than one dollar per MSCF.[23] Based on this range of possible cost, PADD 3 would be expected to have access to hydrogen supplied at a cost of about two dollars per MSCF. PADD 4 is assumed to have to pay the more conservative cost of three dollars per MSCF, and the other PADDs are assumed to incur a cost between PADDs 3 and 4, which would be $2.5 per MSCF. This analysis does not consider numerous other possibilities of providing hydrogen at a reduced cost by using hydrogen recovery technology (which would recover hydrogen from plant gas), or by increasing hydrogen production from the reformer by converting high pressure reformers to low or ultra low pressure reformers.

b. Determination of Blendstock Sulfur Levels

A sulfur balance is performed for each PADD average refinery 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 of the difficulty in gathering the data, and 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. Then, the averaged value, which was determined to be 22 ppm, was compared to the alkylate sulfur levels used in several refinery models. The refinery models alkylate sulfur levels averaged about 10 ppm (the values ranged from 0 to 25 ppm). The difference between the average sulfur level seen in the RFG data base and the average alkylate sulfur levels from the various refinery models was reconciled by presuming that if the average alkylate sulfur level is indeed about 20 ppm, then refiners could decrease alkylate sulfur levels by increasing the severity or better managing existing desulfurization of the alkylate blendstock. 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.

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. For simplicity reasons, the API/NPRA data base was consulted first, however, for reasons explained below, sometimes the RFG database was preferred.

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.

These figures may 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 RFG to be about 150 ppm, no changes in sulfur level are expected to occur to produce Phase II RFG. The PADD 1 blendstock sulfur levels and relative volumes are summarized in Table V-28.

Table V-28. PADD 1 Blendstock Sulfur Levels and Gasoline Pool Fraction

	FCC	*Alkylate*	*Straight Run*	*Coker*
Sulfur (ppm)	442	10	343	3289
Percentage of gasoline pool	42	10	4	0.44
Contribution to pool (ppm)	185	1	14	14

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 affect on the average sulfur level of PADD 2. The PADD 2 blendstock sulfur levels and relative volumes are summarized in Table V-29.

Table V-29. PADD 2 Blendstock Sulfur Levels and Gasoline Pool Fraction

	FCC	*Alkylate*	*Straight Run*	*Coker*
Sulfur (ppm)	924	10	397	0
Percentage of gasoline pool	35	13	3.4	0
Contribution to pool (ppm)	323	1	14	0

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 PADD 3 blendstock sulfur levels and relative volumes are summarized in Table V-30.

Table V-30. PADD 3 Blendstock Sulfur Levels and Gasoline Pool Fraction

	FCC	*Alkylate*	*Straight Run*	*Coker*
Sulfur (ppm)	722	10	139	3255
Percentage of gasoline pool	40	14	2.8	0.42
Contribution to pool (ppm)	288	1	4	14

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 PADD 4 blendstock sulfur levels and relative volumes are summarized in Table V-31.

Table V-31. PADD 4 Blendstock Sulfur Levels and Gasoline Pool Fraction

	FCC	*Alkylate*	*Straight Run*	*Coker*
Sulfur (ppm)	762	10	122	0
Percentage of gasoline pool	31	12	21	0
Contribution to pool (ppm)	236	1	26	0

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 PADD 5 outside of California blendstock sulfur levels and relative volumes are summarized in Table V-32.

Table V-32. PADD 5 Outside of California Blendstock Sulfur Levels and Gasoline Pool Fraction

	FCC	*Alkylate*	*Straight Run*	*Coker*
Sulfur (ppm)	1197	10	41	0
Percentage of gasoline pool	42	10	5.9	0
Contribution to pool (ppm)	503	1	2	0

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. These values are summarized below in Table V-33.

Table V-33. Projected Volume of Gasoline Produced by an Average Refinery in each PADD, by Each PADD of Refineries and 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.

2. The Cost of Desulfurizing Gasoline

a. The Cost of the Averaging Standard

The refinery blendstocks sulfur levels, the vendor desulfurization technology information, the various cost inputs, and various desulfurization assumptions were combined together in a spreadsheet to estimate the cost of desulfurizing gasoline from the base sulfur level, down to various gasoline sulfur levels. A parametric analysis was undertaken to understand how the cost varies in each PADD as the sulfur standard is made more stringent. Costs are estimated for average sulfur standards of 150 ppm, 100 ppm, 80 ppm, 40 ppm and 30 ppm. The costs for desulfurizing gasoline to each of these levels is summarized below in Table V-34.

Table V-34. Per-Gallon Cost of Desulfurizing Gasoline

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5OC*	*U.S. Avg.*
Average Sulfur Level (ppm)	Societal Cost (7 percent ROI and no Income Taxes)					
150	0.8	0.7	0.7	1.2	1.6	0.8
100	1.3	0.9	0.9	1.7	1.9	1.1
80	1.5	1.0	1.0	2.0	2.0	1.2
40	2.1	1.2	1.3	2.8	2.3	1.5
30	2.3	1.4	1.4	3.2	2.8	1.7
ROI	Cost to Refiners of a 30 ppm Average Sulfur Standard					
6%	2.4	1.5	1.4	3.3	2.8	1.7
8%	2.5	1.5	1.5	3.5	2.9	1.8
10%	2.6	1.6	1.5	3.6	3.1	1.9

As seen in the above table, 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 expense of refining, PADD 4 is expected to be the most expensive, and would be about twice as much to desulfurize gasoline as 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 1.8 cents per gallon to desulfurize gasoline down to 30 ppm. The societal cost represents capital amortized based on a seven percent rate of return on investment (ROI), and no income taxes; and this cost was used to calculate cost-effectiveness. We also show that the cost would be 1.8 cents per gallon based on a typical capital recovery scenario for the refining industry, which is based on an eight percent ROI and taxes included. As a sensitivity, we also show the cents per-gallon cost for six percent and 10 percent ROI. Both the societal cost and typical refinery cost are intended to represent the average cost across an entire PADD. Individual refiners within a PADD are expected to experience costs which are either higher or lower than these costs. The societal costs are shown in graph form in Figures V-2 - V-7 at the end of this Section.

To help the reader better understand the cost of the program for a typical refinery, the per-refinery costs for 150 ppm and 30 ppm are summarized in Table V-35, below.

Table V-35. Estimated Average Per-Refinery Capital and Operating Cost of Desulfurizing Gasoline to 150 ppm and 30 ppm

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5OC*	*U.S. Avg.*
150 ppm						
Capital Cost ($MM)	30	23	21	10	17	22
Operating Cost ($MM/yr)	8	6	7	3	12	7
30 ppm						
Capital Cost ($MM)	73	40	40	23	25	43
Operating Cost ($MM/yr)	25	13	15	9	21	15

Table V-34 shows that, on average, refiners would have to pay out $43 million in capital costs for each refinery to lower gasoline sulfur to 30 ppm. In addition, each refinery would incur about 15 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. To meet a 150 ppm standard, the capital and operating costs are about half as much as having to meet a 30 ppm standard. Once again, since these figures are averages, larger refineries with high gasoline sulfur levels will experience higher costs, while smaller refineries with lower sulfur levels will experience lower costs.

The estimated yearly aggregate cost to the country, and to importers, of meeting 30 and 150 ppm sulfur standards is summarized in Table V-36, below.

Table V-36. Aggregate Cost of Desulfurizing Gasoline to 150 ppm and 30 ppm

	PADD 1	*PADD 2*	*PADD 3*	*PADD 4*	*PADD 5OC*	*U.S. Total*	*U.S. Total w Foreign Cost*
150 ppm							
Capital Cost ($MM)	380	640	810	140	260	2230	2450
Operating Cost ($MM/yr)	90	160	310	40	80	680	750
30 ppm							
Capital Cost ($MM)	930	1100	1850	340	390	4650	5100
Operating Cost ($MM/yr)	290	340	630	110	150	1520	1670
Year which Capital Dollars are Expended						*Amount ($MM)*	
2001						145	
2002						727	
2003						1018	
2004						1358	
2005						1455	

Table V-35 shows that the aggregate capital cost to the U.S. refining industry for meeting the proposed 30 ppm sulfur standard is expected to total about 4.7 billion dollars. With the implementation of an averaging, trading and banking program, these capital investments are expected to be spread out over several years. The bottom of Table V-35 summarizes our forecast of the capital dollars expended during each year which the refining industry is expected to make investments. This level of capital expenditure is less than previous capital expenditures made by the refining industry for environmental programs. In 1996, the Energy Information Administration studied and reported on the capital investment made by the major energy producing companies in the U.S. during the early nineties.[24] During this time, these companies invested from 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 were incurred by less than three quarters of the refining industry, we believe that a program requiring the entire industry to spend up to one and one half billion dollars of capital costs per year over several years is not unreasonable. The aggregate operating cost to the U.S. refining industry is expected to be about 1500 million dollars per year. When considering the cost to foreign refiners, the capital and operating costs of this program would increase to 5.1 billion dollars and 1670 million dollars per year, respectively.

b. Verification of the Desulfurization Cost Based on the Improved Technologies

Shell Oil engineers (who now work for Equilon) provided EPA their estimate of the cost of a 40,000 barrel per day CDTECH unit. The Shell cost estimate showed substantially higher costs in certain areas compared to the CDTECH estimates (based on a May 1998 CDTECH cost estimation booklet)[25]. Later (September and December 1998), CDTECH provided updates on their costs, and the most updated cost table was integrated into our cost analysis spreadsheet. We compared the new CDTECH costs to the Shell Oil costs and the previous CDTECH costs, and summarized the comparison here. The sulfur reduction case which we costed out is consistent with the past cost comparison between the early CDTECH costs and the Shell engineers' calculated costs, which is 90 percent FCC gasoline desulfurization. We presumed that the comparison was done for a Gulf Coast refinery, which would be in PADD 3, thus the cost inputs we developed for PADD 3 above were used here. The cost comparison is summarized in Table V-37 below.

Table V-37. Summary of the Cost of Desulfurization by the CDTECH Process Based on 90 percent Desulfurization Severity

	Previous CDTECH costs	*Shell*	*Adjusted Shell costs*[g]	*EPA (costs revised by CDTECH Dec. '98)*
Capital Onsite $/BBL	375	600	660	690
H2 Reqd. SCF/BBL	60	200	80	68
Octane Value CPG	0.6	1.0	1.0	0.7
Hydrogen Cost ($/MSCF)	3	3	3	2
$/BBL FCC Gasoline				
Maint(5%&4%Cap) ($/BBL)	0.10 (5%)	0.16 (5%)	0.16 (5%)	0.09 (4%)
Catalyst ($/BBL)	0.10	0.10	0.10	0.15
Utilities ($/BBL)	0.07	0.10	0.10	0.19
H2 ($/BBL)	0.18	0.60	0.24	0.13
Octane ($/BBL)	0.25	0.42	0.42	0.27
Net Misc Downgrades ($/BBL)	0	0.10	0.10	0
Total ($/BBL)	0.70	1.48	1.12	0.83
c/gal Gasoline Pool (FCC fract is 0.34)	0.57	1.20	0.91	0.67

As depicted in the above table, CDTECH's revised capital costs are substantially higher than the initial costs, and, after adjusting the Shell costs to include the cost for a hydrogen

[g] Costs are adjusted to add a recycle compressor which, according to the Shell engineers, would reduce hydrogen loss by over fifty percent, add to the capital cost by approximately 10 percent (about two million dollars), and would, according to Shell, add a small cost to downgrades (not specified).

compressor, the revised CDTECH and the Shell capital costs are essentially the same. The operating costs are closer now as well. Improved agreement in the operating costs occurs because CDTECH's revised costs are somewhat higher in operating cost, and the adjustment in Shell's hydrogen consumption to account for the addition of a hydrogen compressor dramatically reduced the hydrogen cost. There are still cost differences between the Shell costs and the costs we develop in our analysis. Most of the differences occur because of three cost factors.

The first cost factor which differs is the cost of hydrogen supply. Shell used three dollars per MSCF compared to two dollars per MSCF in our analysis. In a conversation with one of the Shell engineers, he stated that their hydrogen cost which they used was conservative. This suggests the possibility that their cost estimating procedure may be conservative to provide a safety factor for their cost analysis. Another cost factor which differs is the cost of maintenance. Shell used a five percent cost rate while we used a four percent rate. Similarly, Shell later informed us that the five percent maintenance cost factor could be conservative and that a four percent factor is also a reasonable factor to use. For the octane cost factor, Shell used a one cent per gallon factor while we used a 0.7 cents/gallon cost factor. We believe our estimate is reasonable because it is based on the actual cost of making octane in PADD 3. In our analysis, the cost of making octane is higher in other PADDs and considering those other costs would increase our cost somewhat making our cost closer to the cost used by Shell. Finally, Shell added a 0.1 dollar per barrel cost for downgrades, which provides for potential yield loss from the CDTECH unit. Shell said that they add the factor to account for all losses from the unit. We called CDTECH to ask them whether there are any losses from their desulfurization unit, they stated that there is none. We are presuming that there is none. If the Shell costs were calculated using these same cost factors which we used, their operating cost would decrease to 0.78 dollars per barrel for the FCC gasoline and 0.63 cents per gallon for the entire gasoline pool, which is essentially identical to our costs.

In summary, the revised CDTECH costs for their desulfurization unit brings their costs much closer to the Shell costs. Since the Shell analysis of the CDTECH may have some conservative cost factors involved, adjusting their analysis for these factors closes the remaining gap between the two analyses. Shell engineers' review of the cost of using CDTECH CDHydro and CDHDS corroborates the revised costs provided CDTECH, which corroborates that portion of our analysis.

We have no third party verification of Mobil Oil's cost factors for their third generation Octgain process. However, Mobil has monitored its own track record for estimating the performance of a full scale unit based on pilot plant data. They went through this process two times since they created two different generations of the Octgain process before this third generation was created. Based on this experience, Mobil Oil feels confident that their process will operate in a refinery as claimed.

c. Future Cost of Desulfurization

Like any refinery processing unit which was newly installed, the per-barrel cost will normally decrease over time. We discussed how this change in cost would occur with several different refining industry consultants who cited the following reasons.

Two of the consultants stated that the per-gallon costs could be expected to decrease further through engineering improvements in the process. Normally, the vendor which licensed the technology will discover engineering changes to the unit that would reduce its operating cost, although the refinery engineering and operations staffs can also make such discoveries. Engineering changes would be expected to occur in the catalyst technology which would lower operating cost such as reduced hydrogen utilization, and reduced octane and yield loss.

Two of the consultants mentioned that a another type of cost reduction can occur incrementally over time due to debottlenecking of the process throughput. The debottlenecking of this unit would occur in step with the debottlenecking of other gasoline producing units, such as the FCC unit, to help increase gasoline production to meet increased gasoline demand. Such increases in throughput would result in decreased per-barrel fixed operating cost, such as operating labor and maintenance costs, and insurance and other similar costs.

One consultant stated that refinery operations personnel will learn to operate the process more efficiently. These improvements would most likely help to reduce operating cost, such as improved energy utilization, reduced electricity demand and decreased operating labor and maintenance costs. However, the other two consultants seemed to think that these sort of improvements are less likely, as refiners have learned to already squeeze the most efficiency from their refinery units.

Processing unit improvements can also reduce the capital cost of the improved technologies. Capital improvements can primarily be taken advantage of when the unit is first installed. However, units installed for 2004 will already be sunk investments if improvements to the design of these technologies are discovered later. Thus, capital improvements would probably not be taken advantage of until new investments are made in these desulfurization processes.

For this analysis, we presumed that there would be reductions in costs in the ways stated by at least two of the refinery consultants. First, there is a presumed reduction in operating cost due to an improvement in catalyst technology. Similar to the estimate of future motor vehicle costs, operating costs are presumed to decrease by 20 percent after two years. This improvement is expected to occur in the catalyst cost, hydrogen cost, and decreased octane and yield losses. This improvement in operating cost is presumed to only happen once, although the reduction applies to additional throughput created through debottlenecking.

A second reduction in cost occurs in fixed operating cost because the unit is debottlenecked to keep up with increased gasoline demand. Since there are no new refineries being built, the increase in gasoline demand is presumed to occur by the existing refiners which currently produce gasoline for the U.S. Gasoline consumption is presumed to increase at the same rate as VMT is presumed to increase, and this growth rate is 2.05 percent per year. Since capital is sized larger than necessary by a 15 percent margin, the first eight years of debottlenecking are presumed to occur with no new capital expenditures. Then, as capital must be invested to increase throughput, the newly invested capital is presumed to cost one-third of the originally invested capital on a per-barrel basis. The ratio of one-third presumes that debottlenecking would cost about half of the inside battery limit capital cost. These debottlenecking capital costs are also amortized at a seven percent rate of return over a 15 year period. The variable operating costs for the increased barrels desulfurized are presumed to be the same on a per-barrel basis as the original throughput. However, the fixed operating costs of the original equipment are presumed to stay the same, thus the same fixed costs are spread over a larger volume of gasoline produced.

A third type of cost reduction occurs for future capital investments in desulfurization units. This new investment is assumed to be made after 15 years, which is the assumed economic life and project life of these units and the point at which they would have to be replaced. At that point, the capital cost is presumed to be 20 percent lower than the cost in 2004. Presuming that refiners would reinvest in capital after 15 years is probably conservative since most refineries today are still using originally installed equipment which was erected 20, 30 and sometimes even 50 years ago.

As expected, the implementation of these cost assumptions results in a decreasing cent-per-gallon cost over time. The estimated future national cost of desulfurizing gasoline are summarized below in Table V-38.

Table V-38. Projected Future Average Per-Gallon National Cost of Desulfurizing Gasoline to 30 ppm

Year	*Cost (cents per gallon)*
2004	1.68
2005	1.67
2006	1.54
2007	1.52
2008	1.51
2009	1.49
2010	1.47
2011	1.45
2012	1.44
2013	1.42
2015	1.40
2020	1.38
2025	1.30
2030	1.23

d. Comparison with Previous Cost Estimates

Over the last several years, EPA and other organizations have estimated the cost of sulfur control. In our recent technical report entitled "EPA Staff Paper on Gasoline Sulfur Issues," we provided a cost estimate for reducing sulfur in gasoline. That cost is summarized here in Table V-39 along with our current costs.

Table V-39. Cost of Desulfurizing Gasoline by Refiners in PADDs 1 & 3 Reported in the "EPA Staff Paper on Gasoline Sulfur Issues," and our Current Costs.

	Base to 150 ppm	*Base to 100 ppm*	*Base to 40 ppm*
Previous Cost (c/gal)*	1.1 - 1.8	1.9 - 3.0	5.1 - 8.0
Current Cost (c/gal)**	0.7	1.1	1.6

* Based on Octgain 125 (second generation) technology, and calculated with the ORNL refinery model with excessively high reformate sulfur levels, among other problems which tended to overestimate costs.

** Based on improved gasoline desulfurization technologies assuming a typical refinery capital cost recovery.

Most of the difference in cost between these two cost estimates can be explained by a couple factors. The most important factor is the type of desulfurization hardware which we presumed would be used by the refining industry. For our previous cost study, we worked with the Department of Energy to develop costs using refinery model run by the Oak Ridge National Laboratory (ORNL). That refinery model chose Mobil Oil's Octgain 125, which is the second generation of the Octgain process. Octgain 125 must be operated under very severe conditions (higher temperature and pressure) to realize the octane recovery which the process is designed to deliver. However, the more severe conditions also results in higher capital and operating costs than that incurred by these improved gasoline desulfurization technologies. To quantify the cost reduction of the improved technologies relative to what we were modeling with previously, we put the inputs of the older Octgain process into our spreadsheet and developed a cost curve at the different sulfur levels modeled. Since we only are trying to get a sense of the cost reduction for the older Octgain process relative to the improved technologies, we only developed the cost curve for Octgain 125 for PADD 3. A comparison of the cost of desulfurizing gasoline is summarized below in Table V-40.

Table V-40. A Comparison of the Per-Gallon Gasoline Desulfurization Cost of Improved Desulfurization Technologies to that of the Earlier Mobil Octgain Process for PADD 3

	150 ppm	*100 ppm*	*80 ppm*	*40 ppm*	*30 ppm*
Mobil Octgain 125	1.1	1.7	2.0	2.6	2.9
Improved Desulfurization Technologies	0.7	1.0	1.1	1.3	1.5

This comparison shows that the difference between our current costs and our previous costs for 150 and 100 ppm can mostly be explained by the difference in the technologies we used in our modeling. To reach a low gasoline sulfur standard of 40 or 30 ppm, the improved desulfurization technologies are nearly 50 percent less costly than the older technology. This difference explains a part of the cost difference between these two studies, but not all the cost difference. Probably the next most important factor is a problem which was discovered with the refinery model which we were modeling with at the time. That model assigned reformate a sulfur level of 35 ppm, which is normally 1 ppm or less. Achieving low sulfur levels with the previous Octgain process caused a significant loss in octane and yield. Increasing either the volume or octane of reformate would have been a likely source of the needed octane. However, the refinery model did not select either of these options, due to the fact that the reformate sulfur level was so high and could not be reduced. Thus, the refinery model had to find other more costly ways to make up the octane losses caused by desulfurization, which likely increased cost. The same refinery model was later run with reformate sulfur levels reset to low levels. This run showed that this problem with the reformate sulfur level may have increased the cost of desulfurization by as much as 1.5 cents per gallon. Thus, an unreasonably high reformate sulfur level explains another large portion of the difference between the two studies.

Another possible reason for this difference in cost between the two studies is that we are estimating costs using a simpler refinery model which focuses primarily on the sulfur content of gasoline, instead of a more sophisticated refinery model, which attempts to optimize production volumes and quality all at the same time. The advantage of the simpler model is that the source of all costs is clear and can be easily evaluated. The disadvantage is that some aspects of refinery operation, such as making up lost octane or gasoline yield, is handled in a fairly simple fashion (e.g., by adding the current market cost of increasing octane or of producing gasoline). The disadvantage of the more complex linear programming refinery models is that it is very difficult for anyone except the operator of the model to understand why the model is making certain decisions or the cause of many of the projected costs. The example of the over-estimated reformate sulfur level is a case in point, as this problem and its impact on costs was not at all obvious. On the other hand, the more complex models attempt to more realistically simulate the actions which would be required for refiners to make up lost octane or gasoline volume. This presumes that the model reflects all of the flexibilities and constraints facing refiners in accomplishing these goals. Again, this is difficult to determine given the complexity of both refining and these refinery models.

For example, some uncertainty exists concerning the cost of supplying hydrogen. Since refinery cost data is not available for estimating hydrogen cost, we are using cost factors which we believe are reasonable, but may slightly over or underestimate costs. A more complex refinery model would include one or more hydrogen producing processes. However, the fundamental operating and capital costs of these processes are usually not published and cannot therefore be evaluated.

Differences in capital recovery used to develop the two different sets of costs shown in Table V-39. provide a negligible impact on the cost difference.

An important point deserves to be made concerning the improvement which Mobil Oil has made with its Octgain technology over the last several years. As seen in Table V-39, the desulfurization cost to achieve a low sulfur gasoline with their later technology is about half as much as with their earlier technology. This improvement over a several year period of timeframe corroborates our assumptions above that desulfurization cost will decrease in future years.

3. Other Effects of This Program

a. Effect of the Cap Standard

In addition to the 30 ppm averaging standard, we are proposing a 80 ppm per-gallon standard. The per-gallon standard or cap on sulfur level provides an additional challenge to refiners by preventing them from producing moderate and high sulfur batches of gasoline. While the averaging standard would force refiners producing higher sulfur gasoline to produce lower sulfur gasoline on average, which would be comprised mostly of batches of low sulfur gasoline along with occasional batches at a moderate sulfur level, a sulfur cap would preclude refiners from producing a single batch of gasoline with moderate sulfur levels that would exceed the cap.

High sulfur batches of gasoline would likely be produced 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.

During conversations some time ago with the economics committee of API, we discussed how we could estimate the cost of a cap standard. The committee’s response was that the cost of the cap standard could be estimated by estimating the average sulfur level which would result from the cap standard. Later on, API sent us a letter which stated that the relationship between a cap standard and the resulting average sulfur level could be estimated from the variation in current gasoline sulfur levels presuming that the cap would represent the 90th percentile of that variation. The cost of meeting the cap standard could be estimated by estimating the cost of reducing gasoline sulfur to meet the average sulfur level determined by this relationship. Based on this advice, we analyzed this relationship using gasoline batch sulfur levels provided to EPA for the Reformulated Gasoline Program. We also compared the proposed API methodology for estimating the relationship between the cap and averaging standards to current capped sulfur levels. We put the results of that study in the EPA Staff Paper on Gasoline Sulfur Issues.

The analysis showed that if a 80 ppm cap standard were established, the resulting averaging standard would be in the range of 30 ppm to nearly 50 ppm. Because the averaging standard is at the lower end of this range, this suggests that the cap standard would not control the average gasoline sulfur level. Instead, the 30 ppm average standard would be the primary controlling standard, and if the cap standard did not exist, then while meeting the 30 ppm averaging standard, refiners would occasionally produce gasoline which exceeded the 80 ppm sulfur level (our analysis shows probably about five percent of the time). The addition of the 80 ppm cap would require refiners to modify their refinery operations further to not produce batches of gasoline with sulfur levels that would exceed the cap standard.

Since refiners are likely producing these high sulfur batches because they are not trying to control gasoline sulfur now, stopping the production of these batches may not be a difficult task. However, in our analysis of the relationship of the cap and averaging standards, the refiners which have lower sulfur levels now are probably at that level because they are using sweet crude oils, or don’t have a FCC unit which elevates the sulfur level in gasoline. Sour crude refiners, in the day-to-day variances in their refining operations, may have a more difficult time preventing the occurrences of high sulfur gasoline batches. Their gasoline sulfur levels is expected to be very high if their desulfurization units were to fall into disrepair, or would vary more widely when any of the situations summarized above which cause variance in gasoline sulfur levels were to occur. To manage this situation in those refineries, the refinery managers would likely have to do a better job managing the entire refinery, not just the gasoline desulfurization unit, to deliver low sulfur gasoline. This improved operations management would likely involve changes in the computer systems which control the refinery operations. There would likely have to be better management of the maintenance performed refining processing units. Refiners would likely focus in improving the operations and maintenance of critical units which divert sulfur into gasoline, or remove sulfur. However, after this is done, the refinery would likely recoup at least some, or perhaps even all of the cost disbursed to make these improvements in refinery operations from other improvements in refining operations.

Another change which refiners could make in their refining operations is to invest in a gasoline sulfur analyzer. Such analyzers would enable them to meet the per-gallon cap at the lowest possible cost. Refiners normally have to send a gasoline sample out to a lab to determine the actual sulfur level. However, the lag time between when the sample was taken and when they receive the results provides refiners with some uncertainty on whether the gasoline it is producing is indeed meeting the cap standard. This uncertainty could cause refiners to produce gasoline with lower sulfur levels than necessary to ensure that the cap standard would be met. For this reason, refiners may choose to purchase a gasoline sulfur on-line analyzer. This analyzer would keep the refinery manager up to speed on the exact sulfur level in their gasoline. This information would empower refiners with confidence that they will consistently meet the cap standard. According to an analyzer manufacturer which makes such a device, the cost for a gasoline sulfur analyzer would be about 50,000 dollars, and to install it would cost another 5000 dollars. Compared to the capital and operating cost of desulfurizing gasoline, the cost for this addition would be trivial.

If the gasoline desulfurization unit were to break down, or if a number of other problems were to plague the refinery, the refinery would probably be producing gasoline which would exceed the cap standard. Thus the refinery manager would have to take action preventing the sale of off-specification gasoline. The most obvious near term solution would be to blend the gasoline blendstocks together which it can to produce on spec gasoline. If the FCC gasoline hydrotreater went down, the rest of the gasoline blendstocks could probably be blended together to produce on-spec gasoline. However, a portion of the normal gasoline stream, which would be the FCC gasoline, would have to be dealt with until the hydrotreating unit could be brought back on line. There are several potential solutions to this problem. One would be to store the FCC gasoline blendstock until the unit was back on line. Then the stored blendstock could be either run through the desulfurization unit, or blended back with gasoline at a rate which would ensure that the gasoline would still meet the cap standard. If the refinery does not already have a spare tank in which it could store the high sulfur gasoline blendstock, then the refiner would have to build one. Another possibility would be to sell off the blendstock to another refiner, who had the excess desulfurization capacity to process it or blend it in with their gasoline. Since refiners design the desulfurization units using a safety design factor, this excess capacity can be used to process this excess feedstock.

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 demand would be expected due to the price increase in gasoline. This would lead to a corresponding small decrease 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.[26] 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 likely 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.[27] 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.[28] 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.[29] 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, this proposed rule contains multiple provisions which are intended to prevent refinery closures due to financial hardship. The small refiner provisions extend the time which small refiners would have to meet the sulfur standards. Additional time would allow them 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 desulfurization technology. Similarly, refiners which do not fall under the small refinery definition can enjoy some of these same temporal benefits through the Averaging, Banking and Trading program (ABT). The ABT program allows a refiner to phase-in the proposed program across its refineries to its best financial advantage, or gain even more leeway through trades for sulfur credits.

Based on this qualitative review of cost recovery by the refining industry and the benefits of the proposed small refiner and ABT provisions, we do not expect refineries to close as a result of the implementation of the proposed sulfur standards.

c. Refinery Energy and Global Warming Impacts

We estimated the increase in energy consumption in refineries expected to occur from desulfurizing gasoline to 30 ppm by analyzing the specific impact on PADD 3 refineries. Also, consistent with our cost estimation methodology, we performed the analysis presuming that only improved gasoline desulfurization technologies would be used. For this analysis, we first established a baseline energy consumption value for PADD 3 refineries using 1994 Energy Information Administration data, which is the most recent energy consumption data available. We increased the 1994 energy consumption by 2.05 percent per year until 1997, which is the base year of the analysis. (The value of 2.05 percent per year is the projected growth rate for gasoline consumption). This energy consumption calculation is summarized below in Table V-41.

Table V-41. Energy Consumed by PADD 3 Refineries in 1994, Projected to 1997

Energy Type	*Energy Consumed*	*BTU Value*	*MMMBTUs Consumed*
Crude Oil	0 MBbls	-	0
LPG	660 MBbls	3.64 MMBtu/Bbl	2399
Distillate	54 MBbls	5.83 MMBtu/Bbl	315
Residual Oil	998 MBbls	6.29 MMBtu/Bbl	6274
Still Gas	112,538 MBbls	6.00 MMBtu/Bbl FOE	675,200
Petroleum Coke	38,152 MBbls	6.02 MMBtu/Bbl FOE	229,800
Natural Gas	487,115 MM Cuft	1.03 MBtu/CuFt	501,200
Coal	0 MStTons	-	0
Purchased Electricity	20,602 MMKwH	3.41 MBtu/KwH	70.3
Purchased Steam	11,970 MMLbs	0.809 MBtu/Lb	9680
Hydrogen	68,962 MMScf	0.305 MBtu/Scf	21,000
Other Products	252 MBbls	6.00 MBtu/Bbl FOE	1510
Total in 1994			1,438,000
Total in 1997 (Estimated)			1,528,500

Table V-40 shows that the energy consumed by PADD 3 in 1997 is estimated to be 1,500 trillion BTUs.

The increase in energy consumed by desulfurization of the FCC gasoline is calculated by adding up the fuel gas, steam and electricity (in terms of British thermal units (BTUs)) consumed during the desulfurization. First there is the energy consumed running both CDTECH and Octgain processing units. Consistent with how the cost of desulfurization was estimated, each desulfurization technology was presumed to handle half the PADDs desulfurization needs. Then the octane and hydrogen demand had to be met. For both CDTECH and Octgain, extra reformer capacity in PADD 3 was presumed to produce the octane and hydrogen needed for desulfurization. The amount of additional reformer processing capacity needed was based on hydrogen demand, which produced more octane makeup than needed. This estimation methodology likely overestimates the energy consumed since most refiners would probably run the reformers to make up the octane needed. They would then obtain the additional hydrogen needed from excess hydrogen going to plant gas, and make up the refinery plant gas energy loss due to the recovered hydrogen from cheap, unrefined petroleum streams, or by combusting natural gas. However, we had insufficient data for estimating hydrogen recovery from plant gas. Alternatively, reformers could obtain hydrogen from hydrogen plants which consume less energy per quantity of hydrogen produced than the reformer. Finally, half of the Octgain desulfurization processes installed are presumed to need splitters, or distillation columns, to fractionate the FCC gasoline. This additional energy demand is accounted for as well. This presumption may overestimate costs as well for two reasons. First, to get down to 30 ppm, many refiners would likely feed the entire feed to the Octgain unit, and not use a splitter. Second, the splitter data upon which we based our energy demand probably boils off the entire feed, which would not be necessary in this case since only the light ends may have to be boiled off for sending the heavier compounds to the Octgain desulfurization unit. A summary of the estimated CDTECH and Octgain energy and hydrogen demands in PADD 3 is summarized in Tables V-42 and V-43, respectively.

Table V-42. Estimated Yearly Energy and Hydrogen Demand of CDTECH Desulfurization Units in PADD 3

CDTECH Utility Demands	*Process Demand*	*Yearly Throughput*	*BTU Conversion Factor*	*Energy and Hydrogen Consumed*
Electricity	0.5 KwH/Bbl	240 MMBbls	3.41 MBtu/KwH	415 MMMBtu
Fuel Gas	55 MBtu/Bbl	240 MMBbls	-	13,400 MMMBtu
Hydrogen	69 Scf/Bbl	240 MMBbls	-	16,800 MMScf
Reformer				
Electricity	2.6 KwH/Bbl	18 MMBbls	3.41 MBtu/KwH	160 MMMBtu
Fuel Gas	0.048 FOE/Bbl	18 MMBbls	6 MMBtu/Bbl	5240 MMMBtu
Steam	75 Lb/Bbl	18 MMBbls	0.809 MBtu/Lb	1100 MMMBtu
Total				20,300 MMMBtu

Table V-43. Estimated Yearly Energy and Hydrogen Demand of OCTGAIN Desulfurization Units in PADD 3

OCTGAIN Utility Demands	*Process Demand*	*Yearly Throughput*	*BTU Conversion Factor*	*Energy and Hydrogen Consumed*
Electricity	3.6 KwH/Bbl	190 MMBbls	3.41 MBtu/KwH	2950 MMBtu
Fuel Gas	17 MBtu/Bbl	190 MMBbls	-	4080 MMMBtu
Steam	50 Lb/Bbl	190 MMBbls	0.809 MBtu/Lb	9710 MMMBtu
Hydrogen	125 Scf/Bbl	190 MMBbls	-	23,700 MMScf
Splitter			-	
Electricity	2.5 KwH/Bbl	190 MMBbls	3.41 MBtu/KwH	810 MMMBtu
Fuel Gas	0.015 FOE/Bbl	190 MMBbls	6 MM Btu/Bbl	8540 MMMBtu
Steam	10 Lb/Bbl	190 MMBbls	0.809 MBtu/Lb	770 MMMBtu
Reformer				
Electricity	2.6 KwH/Bbl	26 MMBbls	3.41 MBtu/KwH	230 MMMBtu
Fuel Gas	0.048 FOE/Bbl	26 MMBbls	6 MM Btu/Bbl	7400 MMMBtu
Steam	75 Lb/Bbl	26 MMBbls	0.809 MBtu/Lb	810 MMMBtu
Total				32,500 MMMBtu

As these tables show, the average increase in energy demand for the improved gasoline desulfurization technologies, including other changes needed in the refinery to desulfurize gasoline, is estimated to be about 53 trillion BTU's in 1997. This increase in energy use is about 3.4 percent higher than the baseline PADD 3 energy consumption. For the U.S. outside of California, the refining industry is estimated to consume 3000 trillion BTUs per year.[h] Thus the increase in energy demand for the U.S. refining industry, based on PADD 3 and using the 3.4 percent factor calculated above, is estimated to be about 102 trillion BTUs per year. If the additional energy consumed by refiners producing low sulfur gasoline for importing gasoline into the U.S. is considered, the total increase in energy consumed increases to about 122 trillion

[h]This estimate is based on the presumption that PADD 3 consumes 50 percent of the energy in the U.S. outside of California.

BTU's per year.

We next estimated the amount of global warming gas emissions that would be emitted to meet the proposed 30 ppm gasoline sulfur standard. The basis for the estimate is an estimate of carbon dioxide emissions emitted from the combustion of fuels, which is the source of most all refinery energy and, thus, is presumed to be the source of most all refinery emissions of carbon dioxide. The carbon dioxide emission factor is 65,000 grams of CO2 per million Btu of fuel consumed, which is based on the combustion of half natural gas and half liquid petroleum gas (LPG is presumed to emit the same quantity of carbon dioxide per volume fuel consumed as refinery plant gas).[30] For simplicity, this analysis assumes that all BTUs consumed in a refinery are produced by these fuel sources. On this basis, in 2004, CO2 emissions from PADD 3 refineries would increase by 3.4 million tons under the proposed 30 ppm sulfur standard. Across the entire domestic refining industry, carbon dioxide emissions in 2004 would increase by 6.9 million tons. Considering overseas refiners who export gasoline to the U.S., CO2 emissions would increase by 7.5 million tons in 2004, or 2.1 million tons (1.9 million metric tons) of carbon emissions.

This increase is a one-time step increase which represents 0.03 percent of the projected worldwide CO2 emissions inventory in 2004 which is 29.4 billion tons of CO2 per year. This increase also represents 1.2 percent of the total projected increase in worldwide CO2 emissions in 2004 over 2003, which would be 652 million tons. After the step increase, the CO2 emissions increase due to gasoline desulfurization for this program is expected to increase only at or slightly lower than the rate of increase in gasoline demand, which is about two percent. This further increase in CO2 emissions associated with gasoline desulfurization in 2005 and beyond would represent only 0.02 percent of the projected annual growth in worldwide CO2 emissions.

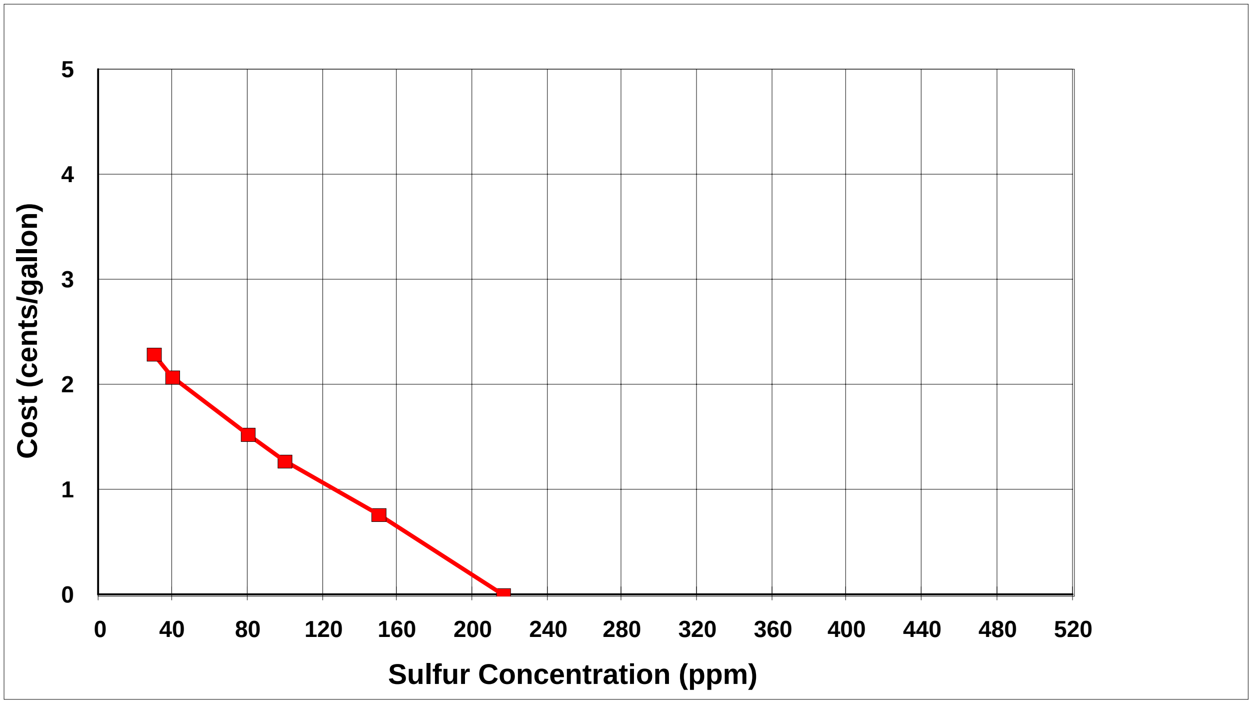

Figure V-2. Cost of Reducing Gasoline Sulfur in PADD 1
(Costs are Based on Improved Gasoline Desulfurization Technologies)

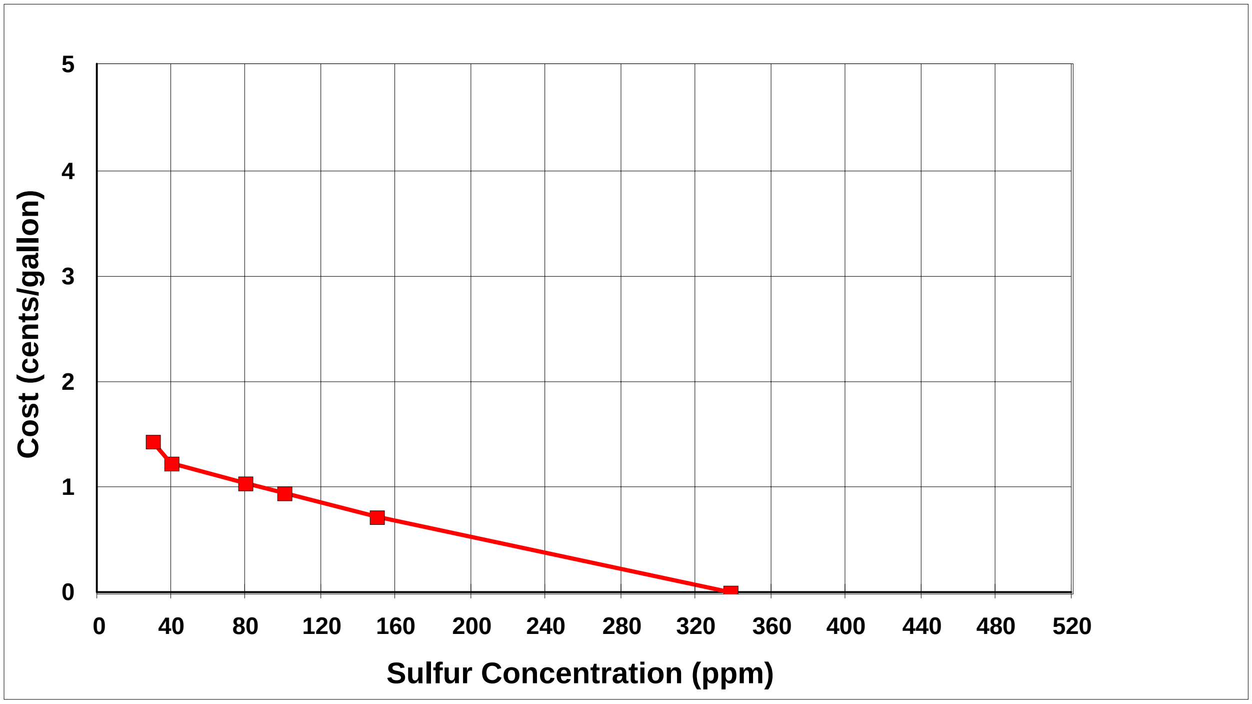

Figure V-3. Cost of Reducing Gasoline Sulfur in PADD 2
(Costs are Based on Improved Gasoline Desulfurization Technologies)

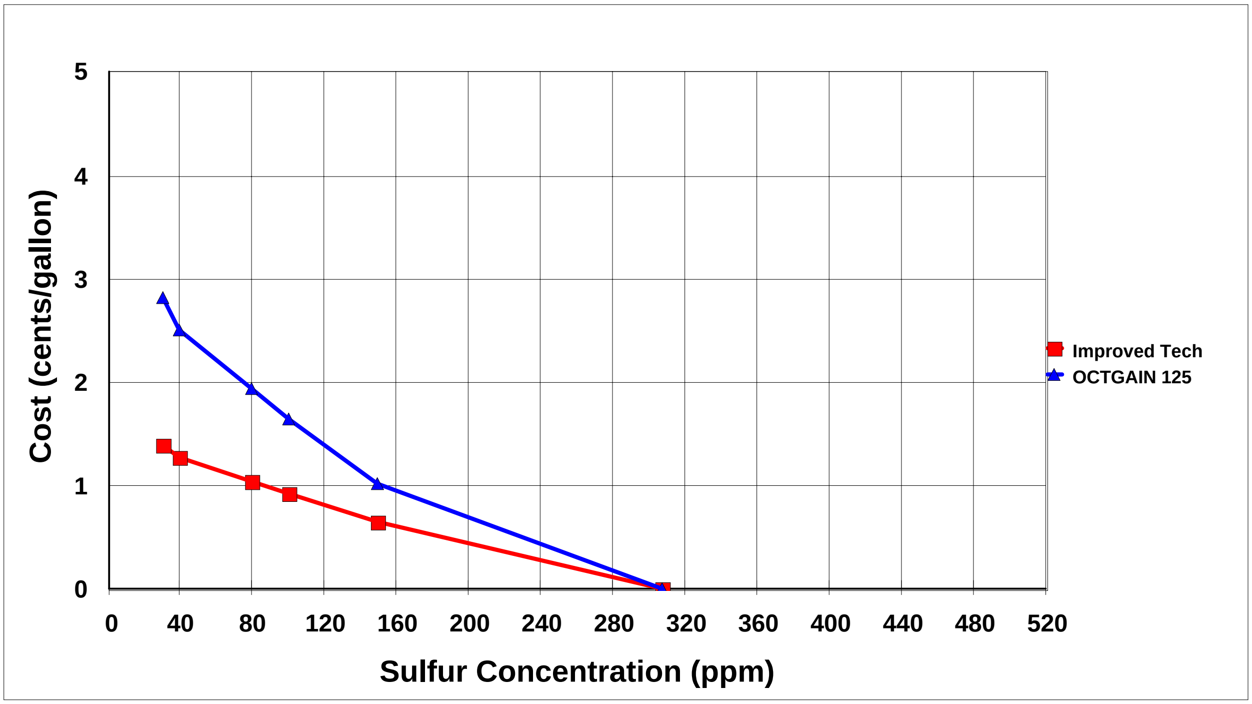

Figure V-4. Cost of Reducing Gasoline Sulfur in PADD 3
(Costs are Based on Improved Gasoline Desulfurization Technologies and Octgain 125)

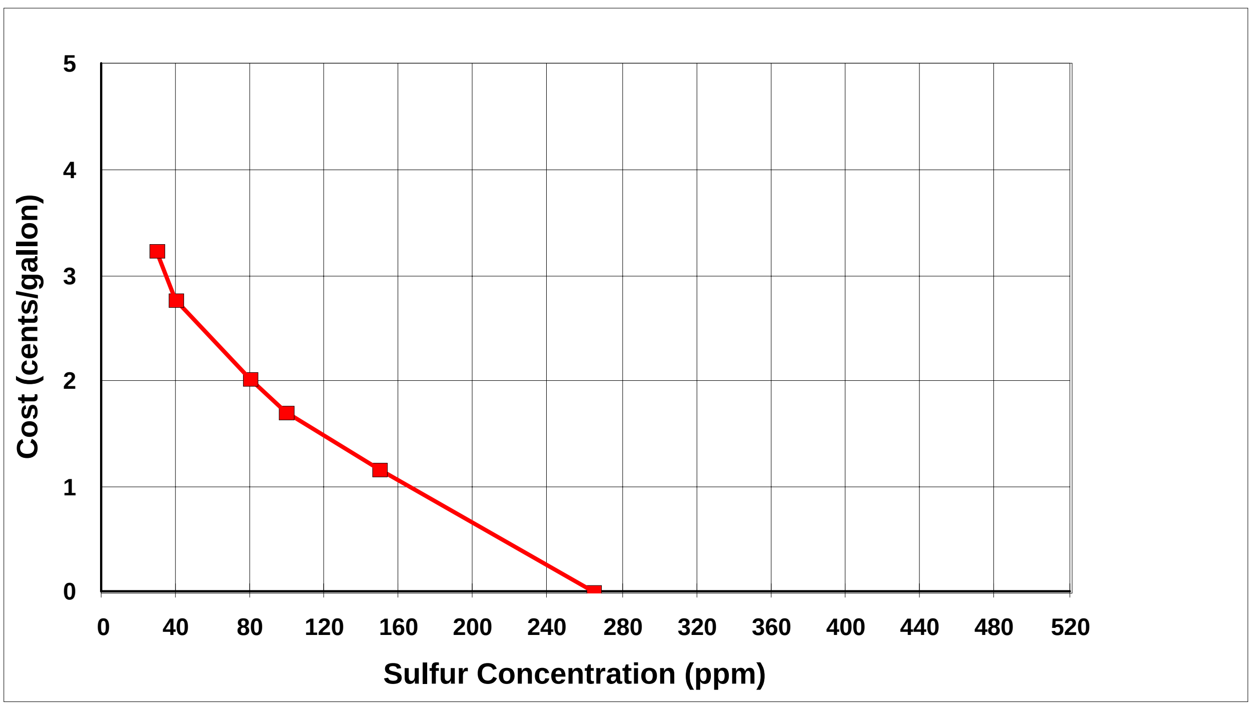

Figure V-5. Cost of Reducing Gasoline Sulfur in PADD 4
(Costs are Based on Improved Gasoline Desulfurization Technologies)

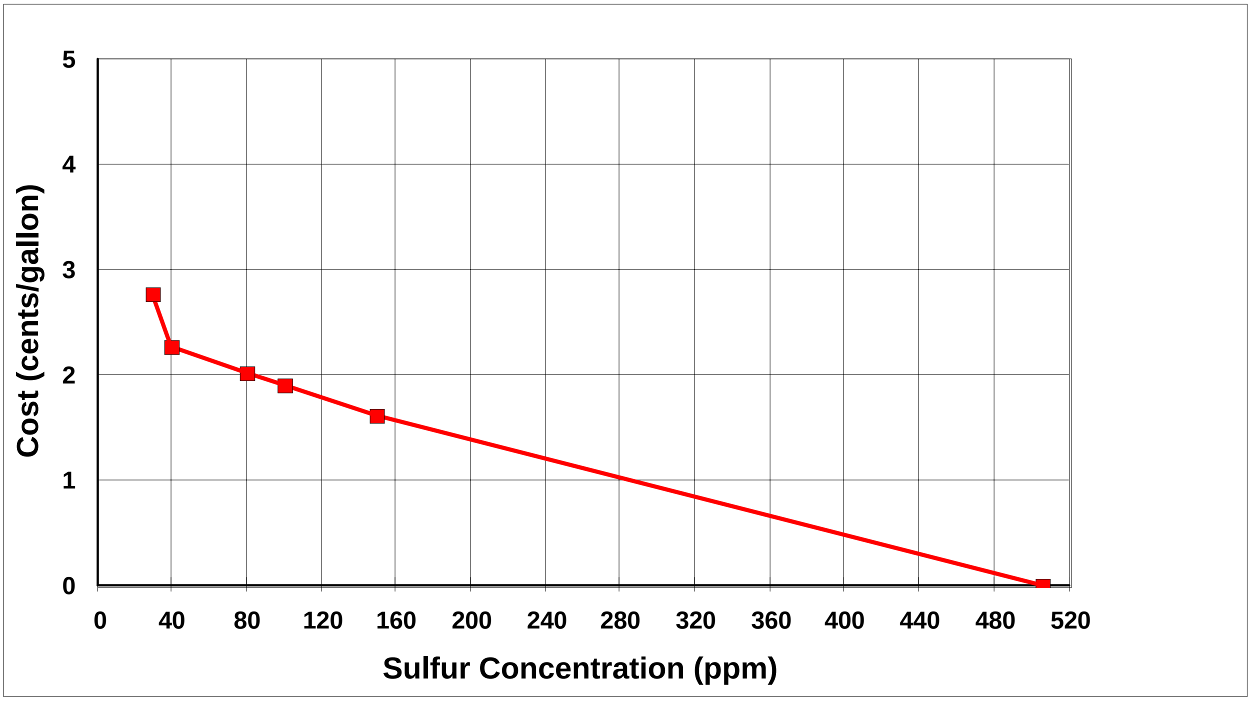

Figure V-6. Cost of Reducing Gasoline Sulfur in PADD 5 Outside of California
(Costs are Based on Improved Gasoline Desulfurization Technologies)

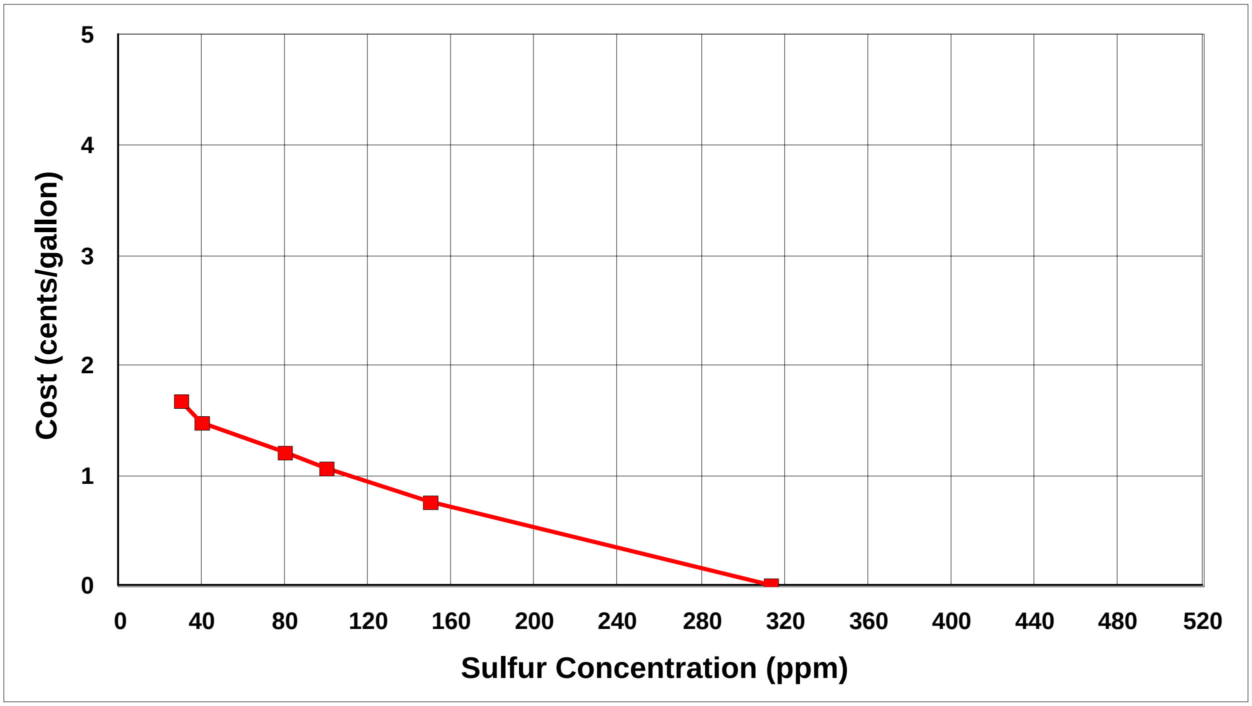

Figure V-7. National Cost of Reducing Gasoline Sulfur Outside of California
(Costs are Based on Improved Gasoline Desulfurization Technologies)

4. 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 proposed 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[31], 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. Using the projected long-term distribution of 40 percent LDV and 60 percent LDT in the fleet[32], 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[i]. Applying the average fuel economy factor of 19.0 miles per gallon and the initial cost for low sulfur fuel of 1.68 ¢/gal leads us to a per-vehicle estimate of $10.17. This is the additional cost that the average vehicle owner will incur in the first year of the program due to the use of low sulfur gasoline.

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:

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[i] Calculated from the annual miles traveled per vehicle for each year of a vehicle's life, multiplied by a distribution of vehicle survival rates 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.

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

Where:

LFC	= Lifetime fuel costs in $/vehicle
$(AVMT)_i$	= Annual vehicle miles travelled in year i of a vehicle's operational life[33]
$(SURVIVE)_i$	= Fraction of vehicles still operating after i years of service[34]
C	= Cost of low sulfur gasoline in $/gal
FE	= Fuel economy in miles per gallon. 24.2 for LDV, 15.5 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 1.68 ¢/gal applies only in the first year of low sulfur gasoline production. In subsequent years, refiners are able to make use of their experience in order to lower their operating expenses. 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 production begins

2) Long-term, representing a vehicle whose operational life begins six years after low sulfur gasoline production begins

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-44.

Table V-44. Undiscounted Per-vehicle Costs of Low Sulfur Gasoline (In 1997 Dollars)

	Near-term ($)	*Long-term ($)*
LDV	83.36	78.15
LDT1, LDT2	178.52	167.56
LDT3, LDT4	192.13	180.28

We then weighted the per-vehicle costs for the individual vehicle categories in Table V-44 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 $142.53 on a near-term basis and $133.73 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:

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

Once again, we calculated lifetime fuel costs separately for LDV, LDT1, LDT2, LDT3, and LDT4. These values are shown in Table V-45.

Table V-45. Discounted Per-vehicle Costs of Low Sulfur Gasoline (In 1997 Dollars)

	Near-term ($)	*Long-term ($)*
LDV	60.98	56.73
LDT1, LDT2	126.95	118.19
LDT3, LDT4	135.85	126.43

Once again, we then weighted the per-vehicle costs for the individual vehicle categories in Table V-45 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 $101.92 on a near-term basis and $94.86 on a long-term basis.

A summary of all per-vehicle fuel costs described in this section is given in Table V-46 below.

Table V-46. Fleet Average Per-vehicle Costs Of Low Sulfur Gasoline (In 1997 Dollars)

	Cost per vehicle ($)
First year	10.17
Lifetime, undiscounted, near-term	142.53
Lifetime, undiscounted, long-term	133.73
Lifetime, discounted, near-term	101.92
Lifetime, discounted, long-term	94.86

5. Aggregate Annual Fuel Costs

Aggregate fuel costs are those costs associated with the increased cost 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).[35] The resultant aggregate annual fuel costs are summarized in Table V-47. It is important to note that the capital costs associated with the proposed sulfur controls have been amortized for this analysis. 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-47. Increased Annualized Fuel Cost as a Result of Today's Proposed Tier 2 Gasoline Sulfur Controls ($Million)

Calendar Year	*Including Non-Road and Excluding California*[j]
2000	0
2004	2,255
2010	2,127
2015	2,156
2020	2,270

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 by 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 stratification of EPA VMT projections between the 8500 to 10,000 trucks and the over 10,000 trucks was done by using both DRI and EPA data. The DRI projections for the 2000 calendar year show that of all gasoline trucks, light and heavy, 2.1 percent are in the over 10,000 pound category. EPA projections show that of all gasoline trucks, light-duty and heavy-duty, 9.1 percent are in the over 8500 pound category. Using these two projected population percentages, the heavy-duty VMT projections were allocated 77 percent to the 8500 to 10,000 category, and 23 to the over 10,000 category. The same calculation was carried out and used for each calendar year from 2000 to 2020, when the split is projected at 86 percent and 14 percent, respectively. These results are shown in Table V-48.

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

[j]The aggregate fuel costs used in the economic impact analysis of today's proposal 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 (less than 0.02 percent) relative to the gasoline consumed by vehicles and trucks under 10,000 pounds.

The projected VMT values within each category (LDV, LDT, HDG<10,000, and HDG>10,000) were then divided by the corresponding DRI projected fuel economy estimates 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. The results are shown in Table V-49.

b. Explanation of Results

The aggregate fuel costs used in the economic impact analysis of today's proposal 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.[k] 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.[36] The highway gasoline consumption, including the non-road contribution and excluding the California contribution, was then 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 of today's proposal include non-road sources because gasoline used to power these sources will incur the increased per gallon cost, but exclude California because today's proposal 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 the increased per gallon cost.

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

The aggregate fuel costs decrease during the early years due to the decreasing per gallon cost associated with improved refining techniques and the pay off of amortized capital costs. The aggregate costs then 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-48. Stratification of Heavy-Duty Gasoline Fleet using Vehicle Count Projections (Counts are in Millions of Vehicles)

CY	S&P DRI <10k (1)	S&P DRI >10k (1)	S&P DRI total truck	S&P DRI %>10k	AMD <6k (2)	AMD 6k-8500 (2)	AMD <8500	AMD 8500-14k (2)	AMD >14k (2)	AMD Total HDG	AMD Total Truck	AMD %>8500	%HDG 8500-10K	%HDG >10k
1997/6	72.03	1.88	73.91											
2000	83.74	1.76	85.50	2.1%	54.91	19.52	74.43	5.22	2.26	7.48	81.91	9.1%	77.5%	22.5%
2001	87.42	1.74	89.16	2.0%	56.91	20.23	77.14	5.41	2.34	7.75	84.89	9.1%	78.6%	21.4%
2002	89.94	1.73	91.67	1.9%	58.94	20.95	79.89	5.60	2.43	8.03	87.92	9.1%	79.4%	20.6%
2003	92.46	1.71	94.17	1.8%	61.00	21.68	82.68	5.81	2.52	8.33	91.01	9.2%	80.2%	19.8%
2004	94.98	1.69	96.68	1.8%	63.09	22.43	85.52	6.02	2.61	8.63	94.15	9.2%	80.9%	19.1%
2005	99.85	1.70	101.55	1.7%	64.97	23.09	88.06	6.15	2.67	8.82	96.88	9.1%	81.6%	18.4%
2006	102.37	1.68	104.05	1.6%	66.62	23.68	90.30	6.28	2.72	9.00	99.30	9.1%	82.2%	17.8%
2007	104.89	1.67	106.56	1.6%	68.29	24.28	92.57	6.42	2.78	9.20	101.77	9.0%	82.7%	17.3%
2008	107.41	1.65	109.06	1.5%	69.98	24.87	94.85	6.55	2.84	9.39	104.24	9.0%	83.2%	16.8%
2009	109.93	1.63	111.57	1.5%	71.68	25.48	97.16	6.70	2.90	9.60	106.76	9.0%	83.7%	16.3%
2010	113.32	1.68	115.00	1.5%	73.24	26.03	99.27	6.78	2.94	9.72	108.99	8.9%	83.6%	16.4%
2011	114.79	1.68	116.47	1.4%	74.24	26.39	100.63	6.87	2.98	9.85	110.48	8.9%	83.8%	16.2%
2012	116.27	1.68	117.94	1.4%	75.26	26.75	102.01	6.96	3.02	9.98	111.99	8.9%	84.0%	16.0%
2013	117.74	1.67	119.41	1.4%	76.27	27.11	103.38	7.04	3.05	10.09	113.47	8.9%	84.2%	15.8%
2014	119.21	1.67	120.89	1.4%	77.30	27.48	104.78	7.13	3.09	10.22	115.00	8.9%	84.4%	15.6%
2015	122.67	1.67	124.34	1.3%	78.23	27.81	106.04	7.19	3.12	10.31	116.35	8.9%	84.8%	15.2%
2016	124.14	1.67	125.81	1.3%	78.83	28.02	106.85	7.24	3.14	10.38	117.23	8.9%	85.0%	15.0%
2017	125.62	1.67	127.28	1.3%	79.44	28.24	107.68	7.29	3.16	10.45	118.13	8.8%	85.2%	14.8%
2018	127.09	1.66	128.75	1.3%	80.05	28.46	108.51	7.35	3.18	10.53	119.04	8.8%	85.4%	14.6%
2019	128.56	1.66	130.23	1.3%	80.66	28.67	109.33	7.40	3.21	10.61	119.94	8.8%	85.6%	14.4%
2020	128.39	1.66	130.05	1.3%	81.28	28.89	110.17	7.45	3.23	10.68	120.85	8.8%	85.6%	14.4%

(1) From S&P DRI World Energy Service U.S. Outlook, Table 17, April 1998; see memo fr. T.Sherwood to Docket A-97-10, 3/22/99

(2) Draft MOBILE6 Fleet Characterization Input Data, OMS/AMD/Jackson, August 1998; uses count projections where 99.2% of LDTs are gasoline & 0.8% are diesel in both the 2000CY & the 2020CY; see memo fr. T.Sherwood to Docket A-97-10, 3/22/99

Table V-49. Calculation of Gasoline Consumption

					PassCar			LDT<8500				HDG 8500-10k					HDG>10k			Totals	
CY	AMD <8500 VMT ex CA,AL,HI Bmiles (1)	<8500 VMT nation Bmiles (2)	%Car (1)	%Truck (1)	AMD PassCar VMT nation Bmiles (3)	S&P DRI PassCar mpg (4)	PassCar Gasoline Consump nation Bgal	AMD LDT VMT nation Bmiles (5)	LDT Gasoline VMT nation Bmiles (6)	S&P DRI <10k Truck mpg (4)	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 (7)	S&P DRI <10k Truck mpg (4)	8500-10k Gasoline Consump nation Bgal	>10k HDG VMT nation Bmiles (7)	S&P DRI >10k mpg (4)	>10k Gasoline Consump nation Bgal	EPA Total Hwy Gasoline Consump nation Bgal	S&PDRI Hwy Gasoline Consump nation Bgal (4), (8)
1997																					120.94
2000	2160	2455	54.7%	45.3%	1342	21.2	63.30	1112	1104	15.9	69.41	0.518	0.589	0.456	15.9	0.03	0.133	7.1	0.02	132.76	132.72
2001	2210	2511	53.1%	46.9%	1333	21.3	62.59	1178	1169	16.0	73.05	0.533	0.606	0.476	16.0	0.03	0.130	7.1	0.02	135.69	134.90
2002	2250	2557	51.5%	48.5%	1318	21.4	61.43	1239	1229	16.1	76.17	0.548	0.623	0.494	16.1	0.03	0.128	7.2	0.02	137.65	137.07
2003	2290	2602	49.9%	50.1%	1300	21.6	60.19	1302	1292	16.3	79.38	0.563	0.640	0.513	16.3	0.03	0.127	7.2	0.02	139.62	139.25
2004	2330	2648	48.4%	51.6%	1281	21.7	58.91	1367	1356	16.4	82.60	0.578	0.657	0.531	16.4	0.03	0.125	7.2	0.02	141.56	141.43
2005	2380	2705	46.8%	53.2%	1266	21.9	57.81	1438	1427	16.5	86.48	0.593	0.674	0.550	16.5	0.03	0.124	7.4	0.02	144.34	142.44
2006	2420	2750	45.2%	54.8%	1244	22.0	56.41	1506	1494	16.6	89.81	0.610	0.693	0.569	16.6	0.03	0.124	7.4	0.02	146.27	144.62
2007	2460	2795	43.6%	56.4%	1220	22.2	54.95	1576	1563	16.8	93.17	0.627	0.713	0.589	16.8	0.04	0.123	7.5	0.02	148.18	146.79
2008	2510	2852	42.0%	58.0%	1199	22.3	53.67	1653	1640	16.9	96.95	0.645	0.733	0.610	16.9	0.04	0.123	7.5	0.02	150.67	148.97
2009	2550	2898	40.6%	59.4%	1177	22.5	52.35	1720	1707	17.1	100.07	0.662	0.752	0.630	17.1	0.04	0.122	7.5	0.02	152.47	151.15
2010	2600	2955	39.4%	60.6%	1164	23.2	50.15	1791	1777	17.3	102.70	0.679	0.772	0.645	17.3	0.04	0.126	7.5	0.02	152.91	151.56
2011	2650	3011	38.3%	61.7%	1153	23.4	49.19	1859	1844	17.5	105.63	0.690	0.784	0.657	17.5	0.04	0.127	7.5	0.02	154.88	152.47
2012	2710	3080	37.3%	62.7%	1149	23.7	48.58	1930	1915	17.6	108.71	0.705	0.801	0.673	17.6	0.04	0.128	7.5	0.02	157.34	153.38
2013	2770	3148	36.5%	63.5%	1149	23.9	48.07	1999	1983	17.8	111.59	0.721	0.819	0.690	17.8	0.04	0.129	7.6	0.02	159.71	154.29
2014	2882	3275	35.8%	64.2%	1172	24.1	48.57	2103	2086	17.9	116.35	0.736	0.836	0.706	17.9	0.04	0.130	7.6	0.02	164.98	155.20
2015	2888	3282	35.2%	64.8%	1155	24.6	46.93	2127	2110	18.2	115.95	0.752	0.855	0.725	18.2	0.04	0.130	7.6	0.02	162.94	157.48
2016	2940	3341	34.7%	65.3%	1158	24.8	46.64	2183	2165	18.4	117.91	0.767	0.872	0.741	18.4	0.04	0.131	7.6	0.02	164.61	158.39
2017	3000	3409	34.2%	65.8%	1167	25.1	46.57	2242	2224	18.5	120.02	0.783	0.890	0.758	18.5	0.04	0.132	7.6	0.02	166.65	159.30
2018	3060	3477	33.9%	66.1%	1178	25.3	46.59	2299	2280	18.7	121.98	0.798	0.907	0.774	18.7	0.04	0.133	7.7	0.02	168.62	160.21
2019	3130	3557	33.6%	66.4%	1195	25.5	46.82	2362	2343	18.9	124.19	0.814	0.925	0.791	18.9	0.04	0.134	7.7	0.02	171.07	161.12
2020	3190	3625	33.4%	66.6%	1211	25.5	47.47	2414	2395	19.0	126.06	0.829	0.942	0.806	19.0	0.04	0.136	7.8	0.02	173.59	161.66

(1) OMS/AMD/Koupal; %Car & %Truck represent % of Light-duty VMT

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

(3) Multiplies <8500 VMT nation by %Car

(4) From S&P DRI World Energy Service U.S. Outlook, Table 17 (mpg values include diesel), April 1998; see memo fr. T.Sherwood to Docket A-97-10, 3/22/99

(5) Multiplies <8500 VMT nation by %Truck

(6) Draft MOBILE6 Fleet Characterization Input Data, OMS/AMD/Jackson, August 1998; uses count projections where 99.2% of LDTs are gasoline & 0.8% are diesel in both the 2000CY & the 2020CY;
see memo fr. T.Sherwood to Docket A-97-10, 3/22/99

(7) Uses S&P DRI data for % of all gas trucks >10k, and AMD data for % of all gas trucks >8500, then calculates % of all >8500 gas trucks in the 8500-10k category, and % of all >8500 gas trucks in the >10k category.

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

Table V-50. Aggregate Annualized Fuel Costs per Year from 2004 to 2020

CY	EPA Total Hwy Gasoline Consumpnation Bgal	Total Hwy Gasoline Consumption excluding CA Bgal (1)	Non-road Gasoline Consumption excluding CA Bgal (2)	Tier2 Cost ex CA & incl NonRoad $B (3)
1997				
2000	132.76	118.16	7.56	0
2001	135.69	120.76	7.73	0
2002	137.65	122.51	7.84	0
2003	139.62	124.26	7.95	0
2004	141.56	125.99	8.06	2.255
2005	144.34	128.47	8.22	2.276
2006	146.27	130.18	8.33	2.136
2007	148.18	131.88	8.44	2.138
2008	150.67	134.09	8.58	2.147
2009	152.47	135.70	8.68	2.147
2010	152.91	136.09	8.71	2.127
2011	154.88	137.84	8.82	2.129
2012	157.34	140.03	8.96	2.142
2013	159.71	142.14	9.10	2.154
2014	164.98	146.83	9.40	2.204
2015	162.94	145.01	9.28	2.156
2016	164.61	146.50	9.38	2.158
2017	166.65	148.32	9.49	2.166
2018	168.62	150.07	9.60	2.172
2019	171.07	152.25	9.74	2.264
2020	173.59	154.50	9.89	2.270

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

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

(3) OMS/FED/Wyborny; Tier2 $/gal increase

CY	Adj Cost $/gal	CY	Adj Cost $/gal
2004	0.01682	2013	0.01424
2005	0.01665	2014	0.01411
2006	0.01542	2015	0.01397
2007	0.01523	2016	0.01385
2008	0.01505	2017	0.01372
2009	0.01487	2018	0.01360
2010	0.01469	2019	0.01398
2011	0.01452	2020	0.01381
2012	0.01438		

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-51 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-51 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.

Table V-51. Total Incremental Per Vehicle Costs to Consumers Over the Life of a Tier 2 Vehicle

	LDV ($)	*LDT1 ($)*	*LDT2 ($)*	*LDT3 ($)*	*LDT4 ($)*
Near-term Costs					
Vehicle costs	80	73	136	274	270
Fuel costs*	61	127	127	136	136
Total	141	200	263	410	406
Long-term Costs					
Vehicle costs	50	47	103	218	213
Fuel costs*	57	118	118	126	126
Total	107	165	221	344	339

* Discounted lifetime fuel costs in 1997 dollars

2. Combined Total Annual Nationwide Costs

Figure V-8 and Table V-52 summarize EPA's estimates of total annual costs to the nation both for Tier 2 vehicles and low sulfur gasoline.[1] 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. Increases in fuel consumption over time are generally off-set by decreases in per gallon costs. 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 $3.7 billion. Annual costs then drop to about $3.5 billion, largely due to decreases in vehicle costs. Costs increase gradually after 2012 due to the stabilization of vehicle costs in the long-term and projected increases in vehicle sales and fuel consumption.

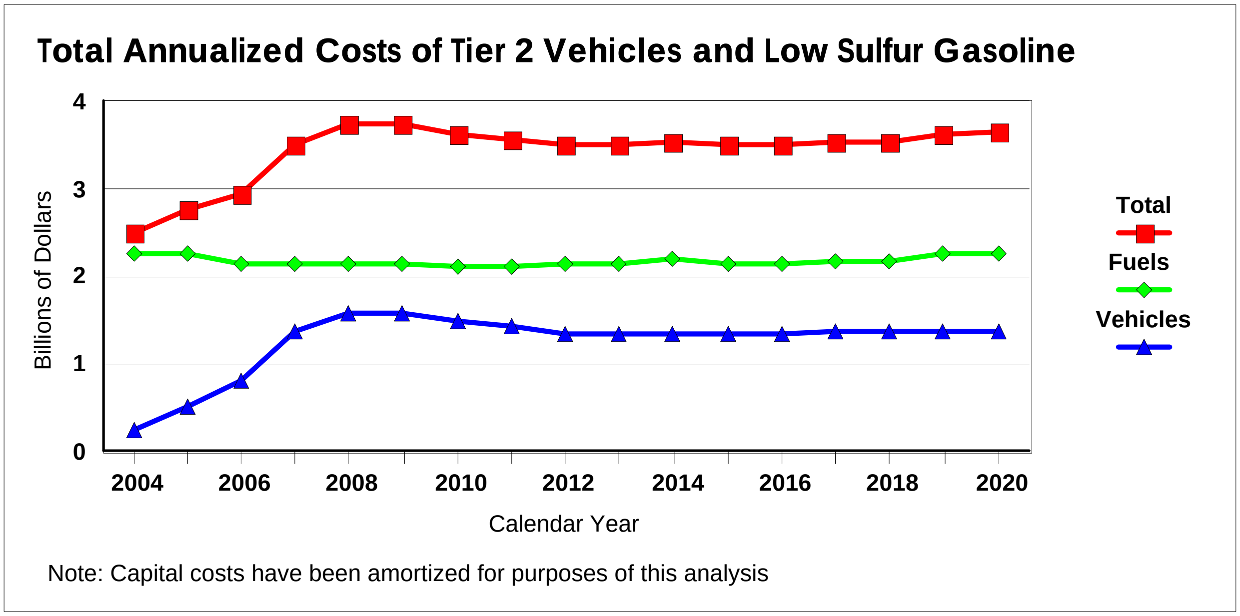

Figure V-8. Total Annualized Costs of Tier 2 Vehicles and Low Sulfur Gasoline.

[1] Excluding vehicles and fuel sold in California.

Table V-52. Total Annualized Costs to the Nation for Tier 2 Vehicles and Low Sulfur Gasoline ($million)

Calendar Year	*Vehicle Costs ($)*	*Fuel Costs ($)*	*Total ($)*
2004	$257	$2,255	$2,512
2005	$506	$2,276	$2,782
2006	$815	$2,136	$2,951
2007	$1,365	$2,138	$3,503
2008	$1,589	$2,147	$3,736
2009	$1,587	$2,147	$3,734
2010	$1,496	$2,127	$3,623
2011	$1,427	$2,129	$3,556
2012	$1,359	$2,142	$3,501
2013	$1,348	$2,154	$3,502
2014	$1,346	$2,204	$3,550
2015	$1,352	$2,156	$3,508
2016	$1,359	$2,158	$3,517
2017	$1,366	$2,166	$3,532
2018	$1,373	$2,172	$3,545
2019	$1,380	$2,264	$3,644
2020	$1,387	$2,270	$3,657

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