The reference case for this analysis includes assumptions for the market penetration of advanced engine and vehicle technologies and resulting improvements in fuel efficiency. Included in the slate of technologies are low rolling resistance tires, improved aerodynamics, lightweight materials, advanced electronic engine controls, advanced turbochargers, and advanced fuel injection systems. Market penetration is estimated using a payback function in which the incremental capital cost for each technology is compared to a stream of fuel savings over a specified technology payback period (1 to 4 years), discounted at 10 percent. In the reference case it is projected that average new truck fuel efficiency will increase from 6.4 miles per gallon in 2000 to 7.4 miles per gallon in 2020.

New vehicle fuel efficiency is reduced slightly in the 4% Efficiency Loss case, but the impact on stock efficiency is marginal because the number of new vehicles expected to enter the market is small relative to the total number of vehicles on the road. Fuel expenditures for heavy trucks are projected to be $1.9 billion higher in 2007 in the 4% Efficiency Loss case than in the reference case, and the difference grows to $2.9 billion in 2011 (Table 1), an increase of $410 in average fuel expenditures per truck. Cumulative fuel expenditures from 2007 to 2015 are projected to be $17.6 billion higher in the Regulation case than in the reference case and an additional $3.0 billion higher in the 4% Efficiency Loss case. The projected cumulative increase in energy use in the 4% Efficiency Loss case is approximately 80 trillion British thermal units (Btu). Energy consumption projections are discussed in Chapter 6.

Table 1. Projected Fuel Expenditures for Heavy-Duty Diesel Vehicles, 2006-2020
(Billion 1999 Dollars)

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total Fuel Expenditures</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reference Case</td>
<td>39.45</td>
<td>40.46</td>
<td>41.46</td>
<td>42.19</td>
<td>42.98</td>
<td>45.96</td>
<td>385.63</td>
</tr>
<tr>
<td>Regulation</td>
<td>41.37</td>
<td>42.31</td>
<td>43.09</td>
<td>44.40</td>
<td>45.55</td>
<td>47.95</td>
<td>403.24</td>
</tr>
<tr>
<td>4% Efficiency Loss</td>
<td>41.37</td>
<td>42.31</td>
<td>43.09</td>
<td>44.58</td>
<td>45.92</td>
<td>48.44</td>
<td>406.21</td>
</tr>
</tbody>
</table>

|                    | Incremental Fuel Expenditures |       |       |       |       |       |                  |
|-------------------|-------------------------------|-------|-------|-------|-------|-------|                  |
| Regulation        | 1.92                          | 1.85  | 1.63  | 2.21  | 2.57  | 1.99  | 17.62           |
| 4% Efficiency Loss| 1.92                          | 1.85  | 1.63  | 2.28  | 2.94  | 2.49  | 20.58           |

Source: National Energy Modeling System, runs DSURF.D043001B, DSU7PPM.D043001A, and DSU7TRN.D043001A.
3. Desulfurization Technology

Introduction

The availability of technologies for producing ultra-low-sulfur diesel fuel (ULSD) was one of the issues raised by the House Committee on Science. First, do adequate and cost-effective technologies exist to meet the ULSD standard? Second, are technologies being developed that could reduce the costs in the future? Last, is it likely that the needed technologies can be deployed into the market in time to meet the ULSD requirements of the rule?

A review of the technologies reveals that current technologies can be modified to produce diesel with less than 10 parts per million (ppm) sulfur. A small number of refineries currently produce diesel with sulfur in the 10 ppm range on a limited basis. The existence of the requisite technology does not ensure, however, that all refineries will have that technology in place in time to meet the new ULSD standards. Widespread production of ULSD will require many refineries to invest in major revamps or construction of new units. In addition to the status of desulfurization technologies, this chapter discusses possible impediments to their deployment.

Refineries in the United States are characterized by a wide range of size, complexity, and quality of crude oil inputs. Upgrades at a given refinery depend on individual circumstances, including the refinery's existing configuration, its inputs, its access to capital, and its perception of the market. The sulfur in petroleum products comes from the crude oil processed by the refinery. Refiners can reduce the sulfur content of their diesel fuel to a limited extent by switching to crude oil containing less sulfur; however, sulfur reduction from a switch in crude oil would fall well short of the new ULSD standard. Refineries will require substantial equipment upgrades to produce diesel with such limited sulfur.

In order to allow for some margin of error and product contamination in the distribution system, refineries will be required to produce highway diesel with sulfur somewhat below 15 ppm. Due to limited experience with such low-sulfur products, the exact sulfur level that will be required by refineries is not certain. In the Regulatory Impact Analysis for the ULSD Rule, the EPA assumed highway diesel production with an average of 7 ppm. Whether production is at 10 ppm or 7 ppm, the same technology would be used. In general, a relatively lower sulfur content would be achieved with more severe operating conditions at a higher cost.

Considerable development in reactor design and catalyst improvement has already been made to achieve ULSD levels near or below 10 ppm. In some cases low sulfur levels are the consequence of refiners’ efforts to meet other specifications, such as low aromatic levels required in Sweden and California. In other cases refiners have decided to produce a “premium” low-sulfur diesel product, as in the United Kingdom, Germany, and California. These experiences, though limited, provide evidence for both the feasibility of and potential difficulties in producing ULSD on a widespread basis.

Refineries currently producing ULSD in limited quantities rely on enhanced hydrotreating technology. Technology vendors expect that this will also be the case for widespread production of ULSD. The following section focuses on hydrotreating as the primary means to achieve ULSD levels. A few emerging and unconventional desulfurization technologies are also discussed, which if proven cost-effective eventually may expand refiners’ options for producing ULSD.

ULSD Production Technologies

Very-low-sulfur diesel products have been available commercially in some European countries and in California on a limited basis. Sweden was the first to impose very strict quality specifications for diesel fuel, requiring a minimum 50 cetane, a maximum of 10 ppm on sulfur content, and a maximum 5 percent on aromatics content. To meet these specifications, the refinery at Skanss, Sweden, installed a hydrotreating facility based on SynTechnology. The Skantras hydrotreating unit consists of an integrated two-stage reactor system with an interstage high-pressure gas stripper. The unit processes a light gas oil (LGO) to produce a diesel product with less than 1 ppm sulfur and 2.4 percent aromatics by volume. It is important to note that the Skantras plant is highly selective of its feedstock to achieve the ultra-low sulfur content which may not be generalized to most U.S. refineries.
In addition to Sweden, other European countries are encouraging the early introduction of very-low-sulfur diesel fuel ahead of the shift to a European requirement for 50 ppm diesel in 2005. The United Kingdom and Germany have structured tax incentives for the early introduction of 50 ppm diesel fuel and have discussed incentives for introduction of a 10 ppm diesel fuel. An example of a European refinery capable of producing diesel fuel for these markets is BP's refinery at Grangemouth, United Kingdom, which has a 35,000-barrel-per-stream-day unit originally designed for 500 ppm sulfur in 1995. The hydrotreater at Grangemouth has a two-bed reactor, no quench, and operates at about 950 pounds per square inch gauge (psig). Operating at a space velocity of 1.5 and using a new higher activity AK30 Nobel catalyst (KF757), the unit is producing 10 to 20 ppm sulfur diesel product. The feed is primary LCO with a sulfur content of about 1,800 ppm, derived from a low-sulfur crude. BP reported that on several occasions the feed had included a small fraction of cycle oil, which resulted in a noticeable increase in catalyst deactivation rate.

In 1999 Arco announced that it would produce a premium diesel fuel—what Arco termed "EC Diesel"—at its Carson, California, refinery. EC Diesel is a "super clean" diesel designed to meet the needs of fleets and buses in urban areas. The reported quality attributes include less than 10 ppm sulfur, less than 10 percent aromatics, and 60 cetane, among others. Arco indicated that the crude profile of the Carson refinery would remain unchanged, with only the operating conditions modified. The refinery had to selectively take out a sulfur-free, aromatic cycle oil feed stream to the diesel unit and repeat this every few days for batches. Continuous production was required, a major capital investment would have to be made. In April 2000, Equilon also announced that its Martinez refinery in Northern California could provide ULSD for fleet use in that region of the State.

The challenge of producing ULSD from feedstocks that are difficult to desulfurize is well represented by the experience of Lyondell-Citgo Refining (LCR) at its refinery in Houston, Texas. In 1997 the refinery moved to a diet of 100 percent Venezuelan crude. The gravity of the crude oil was less than 20 °API, and it was highly aromatic. To produce suitable quality low-sulfur diesel product the refinery had revamped a hydrotreater to SynSat operation in 1996 and then converted to SynShift in 1998. The revamped hydrotreater has a capacity of 50,000 barrels per day and consists of a first-stage reactor operating at 675 psig pressure, a high-pressure stripper, and a second-stage reactor that uses a noble metal catalyst. The feed to the unit is a blend of light cycle oil (LCO), coker distillate, and straight-run distillate (approximately equal volumes) with 1.4 percent sulfur by weight, 70 percent aromatics, and a cetane number of 30. The product has about 40 percent aromatics, a cetane number of 38.5, and sulfur content less than 140 ppm.

Citgo reported that the LCR hydrotreating unit was the largest reactor of its type when installed in 1996 and that the volume of catalyst in the unit, which had been 40,000 pounds in the old unit, had increased to 1.7 million pounds in the revamped unit. The diesel sulfur level produced in the unit reportedly met the 15 ppm sulfur cap at initial conditions at start of run, but as the desulfurization catalyst aged, the reactor temperature had to be revised to achieve target sulfur levels. If the revamped unit had to consistently meet a 15 ppm diesel sulfur limit, the cycle life could be greatly reduced from current operation, causing frequent catalyst replacement and more frequent shutdowns. Under the current mode of operation, the frequency of catalyst changeout is managed by reducing the cracked stocks in the feed to the unit. More frequent catalyst changeouts to meet a 15 ppm sulfur cap reportedly could raise the cost of diesel production.

Hydrotreating

Conventional hydrotreating is a commercially proven refining process that passes a mixture of heated feedstock and hydrogen through a catalyst-laden reactor to remove sulfur and other undesirable impurities. Hydrotreating separates sulfur from hydrocarbon molecules; some developing technologies remove the molecules that contain sulfur (see box on page 16). Refineries can desulfurize distillate streams at many places in a refinery by hydrotreating “straight-run” streams directly following crude distillation, hydrotreating streams coming out of the fluid catalytic cracking (FCC) unit, and/or hydrotreating the heavier streams that go through a hydrocracker. Over half of the streams currently going into highway-grade diesel (500 ppm) are made up from straight-run distillate streams, which are the easiest and least expensive to treat.

50 Now part of BP Amoco.

Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel

9261A

Obtained and made public by the Natural Resources Defense Council, March / April 2002
Refineries with hydrotreating units are likely to achieve production of ULSD on straight runs by modifying catalytic systems and operating conditions. Desulfurizing the remainder of the distillate streams is expected to pose the greatest challenge, requiring either substantial revamps to equipment or construction of new units. In some refineries, the heavier and less valuable streams, such as LCOs, are run through a hydrocracker. The distillates from the cracked stocks contain a larger concentration of compounds with aromatic rings, making sulfur removal more difficult. The need for some refineries to desulfurize the cracked stocks in addition to the straight-run streams may play a key role in the choice of technology.

When the 15 ppm ULSD specification takes effect in June 2006, refiners will have to desulfurize essentially all diesel-blending components, especially cracked stocks, to provide for highway use. It is generally believed that a two-stage deep desulfurization process will be required by most, if not all refineries, to achieve a diesel product with less than 10 ppm sulfur. The following discussion reviews a composite of the technological approaches of UOP, Criterion Catalyst, Haldor Topsoe, and MAKFining (a consortium of Mobil, Akzo Nobel, Kellogg Brown & Root, and TotalFinaElf Research).

A design consistent with recent technology papers would include a first stage that reduces the sulfur content to around 250 ppm or lower and a second stage that completes the reduction to less than 10 ppm. In some cases the first stage could be a conventional hydro-treating unit with moderate adjustments to the operation parameters. Recent advances in higher activity catalysts also help in achieving a higher sulfur removal rate. The second stage would require substantial modification of the desulfurization process, primarily through using higher pressure, increasing hydrogen rate and purity, reducing space velocity, and choice of catalyst. To deep desulfurize cracked stocks, a higher reactor pressure is necessary. Pressure requirements would depend on the quality of the crude oil and the setup of the individual refinery.

The level of pressure required for deep desulfurization is a key uncertainty in assessing the cost and availability of the technology. In its 2000 study, U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels, the National Petroleum Council (NPC) suggested that in order to produce diesel at less than 30 ppm sulfur, new high-pressure hydrotreating units would be required, operating at pressures between 1,100 and 1,200 psig. Pressures over 1,000 psig are expected to require thick-walled reactors, which are produced by only a few suppliers (see discussion later in this chapter) and take longer to produce than reactors with thinner walls. In contrast to NPC’s expectations, EPA’s cost analysis reflected vendor information for revamps of 650 psig and 900 psig units that would require thick-walled reactors. The vendors indicated that existing hydrotreating units could be retrofitted with a number of different vessels, including: a reactor, a hydrogen compressor, a recycle scrubber, an interstage stripper, and related process hardware.

The amount of hydrogen required for desulfurization is also uncertain, because the industry has no experience with widespread desulfurization at ultra-low levels. One of the primary determinants of cost is hydrogen consumption and the related investment in hydrogen-producing equipment. Hydrogen consumption is the largest operating cost in hydrotreating diesel, and minimizing hydrogen use is a key objective in hydrotreating for sulfur removal. In general, 10 ppm sulfur diesel would require 25 to 45 percent more hydrogen consumption than would 500 ppm diesel, in addition to improved catalysts. Hydrogen requirements at lower sulfur levels rise in a nonlinear fashion.

In addition to improvements in design and catalysts, other modifications to refinery operations can contribute to the production of ULSD. For example, high-sulfur components in both straight runs and cracked stocks lie predominantly in the higher boiling range of the materials. Thus, reducing the final boiling point for the streams and cutting off the heaviest boiling segment can reduce the difficulty of the desulfurization task. If a refiner has hydrocracking capability, the hydrocracker would be an ideal disposition for these streams. Some refiners making both high- and low-sulfur distillate products may be able to allocate the more difficult distillate blend streams to the high-sulfur product; however, the EPA is in the process of promulgating "Tier 3" non-road engine.

55The type of improvement in catalyst activity is illustrated by Akzo Nobel’s new KF757 cobalt-molybdenum (CoMo) catalyst. Comparing KF757 with its predecessor catalyst Akzo states, “A diesel unit designed to achieve 500 wppm product sulfur with KF757 can easily achieve less than 250 wppm product sulfur with KF757 while maintaining the same operating cycle.” Source: C.P. Sent, “MAKFining Premium Distillates Technology: The Future of Distillate Upgrading,” presentation to Petrobras (Rio de Janeiro, Brazil, August 24, 2000), p. 4.


Developing Technologies and Ultra-Low-Sulfur Alternatives

Sulfur Adsorption

One new technology on the horizon is the “S Zorb” processing under development by Phillips Petroleum. S Zorb has been promoted for gasoline desulfurization to meet EPA’s Tier 2 requirements. The major distinction of this process from conventional hydrotreating is that the sulfur in the sulfur-containing compounds adsorbs to the catalyst after the feedstock-hydrogen mixture interacts with the catalyst. Thus the catalyst needs to be regenerated constantly. Phillips is promoting the S Zorb process for highway diesel as potentially having lower capital cost than conventional hydrotreating options and reportedly is on the fast track to demonstrate the process in a pilot plant in 2001. Phillips estimates on-site capital costs at $1,000 to $1,400 per barrel per day.

Biodesulfurization

Biodesulfurization is another innovative technology, which uses bacteria as the catalyst to remove sulfur from the feedstock. In the biodesulfurization process, organosulfur compounds, such as dibenzothiophene and its alkylated homologs, are oxidized with genetically engineered microbes, and sulfur is removed as a water-soluble sulfate salt. Several factors may limit the application of this technology, however. Many ancillary processes novel to petroleum refining would be needed, including a biocatalyst fermentor to regenerate the bacteria. The process is also sensitive to environmental conditions such as sterilization, temperature, and residence time of the biocatalyst. Finally, the process requires the existing hydrotreater to continue in operation to provide a lower sulfur feedstock to the unit and is more costly than conventional hydrotreating. Biodesulfurization has been tested in the laboratory, but detailed engineering designs and cost estimates have not been developed.

Sulfur Oxidation

The latest entry in unconventional desulfurization involves sulfur oxidation. This process creates a petroleum and water emulsion in which hydrogen peroxide or another oxidizer is used to convert the sulfur in sulfur-containing compounds to sulfone. The oxidized sulfone is then separated from the hydrocarbons for post-processing. Most of the peroxide can be recovered and recycled. The major advantages of this new technology include low cost, lower reactor temperatures and pressures, short residence time, no emissions, and no hydrogen requirement.

Advocates for the sulfur oxidation technology estimate capital costs at $1,000 per barrel of daily installed capacity—less than half the cost of a new high-pressure hydrotreater. The technology preferentially treats dibenzothiophenes, one of streams that is most difficult to desulfurize, but it does not work as well on straight-run distillate. Because the process removes molecules containing sulfur, some volume losses also occur. One company working on the technology has proposed installation of 1,000 to 5,000 barrel per day units at distribution terminals to “polish” material that might otherwise be downgraded. Construction of a pilot plant is planned, but to date there has been no real-world demonstration of the process.

Fischer-Tropsch Diesel and Biodiesel

One way to add to ULSD supply without desulfurization is to rely on a non-oil-based diesel. The Fischer-Tropsch process, for example, can be used to convert natural gas to a synthetic, sulfur-free diesel fuel. Two gas-to-liquids (GTL) facilities have operated commercially: the Mossgas plant in South Africa with output capacity of 23,000 barrels per day and the Shell Bintulu plant in Malaysia at 12,500 barrels per day. Other plants are in the planning stages.

Commercial viability of GTL projects depends on capital costs, the market for petroleum products and possible price premiums for GTL fuels, the value of byproducts such as heat and water, the cost of feedstock gas, the availability of infrastructure, the quality of the local workforce, and potential government subsidies. Capital costs for GTL projects are currently less than $25,000 per daily barrel of capacity. An EIA analysis of a hypothetical GTL project estimated the cost of GTL fuel at almost $25 per barrel in 1999 dollars. Thus, a GTL project with present technology could be cost-competitive only if investors were confident that crude oil prices would stay in the range of $25 to $30 per barrel and natural gas feedstock prices would remain at 50 cents per thousand cubic feet.

(Continued on page 17)
Developing Technologies and Ultra-Low-Sulfur Alternatives (Continued)

A second way to avoid desulfurization is with biodiesel made from vegetable oil or animal fats. Although other processes are available, most biodiesel is made with a base-catalyzed reaction. A fat or oil is reacted with an alcohol, such as methanol, in the presence of a catalyst to produce glycerine and methyl esters or biodiesel. The methanol is charged in excess to assist in quick conversion and recovered for reuse. The catalyst, usually sodium or potassium hydroxide, is mixed with the methanol. Increased production of biodiesel could create more surfactants than the market would be able to absorb. Biodiesel is a strong solvent and can dissolve paint as well as deposits left in fuel lines by petroleum-based diesel, sometimes leading to engine problems. Biodiesel also freezes at a higher temperature than petroleum-based diesel. Biodiesel advocates claim that a 1-percent blend of biodiesel can improve lubricity by as much as 65 percent. At least eight companies are marketing biodiesel in all parts of the United States, according to the National Biodiesel Board.¹

¹Web site www.biodiesel.org/marketers.htm

emission limits around 2005 or 2006, which are expected to be linked to sulfur reduction for non-road diesel fuel.⁵⁶

A processing scheme that has been promoted primarily in Asia and Europe employs a combination of partial hydrotreatment, which reduces the sulfur content of the fuel. In this scheme a partial conversion hydrotreatment unit is placed in front of the FCC unit to convert the vacuum gas oil to light products (distillate, kerosene, naphtha, and lighter) and FCC feed. The distillate product is low in sulfur (less than 200 ppm) and has a cetane number of about 50. The cracked stocks produced in the FCC unit are also lower in sulfur and higher in cetane. The relatively greater demand for distillate relative to gasoline demand in Europe and Asia and the higher diesel cetane requirement are more in keeping with the strength of this process option than is the case for most U.S. refineries.

A few new technologies that may reduce the cost of diesel desulfurization—sulfur adsorption, biodesulfurization, and sulfur oxidation—are in the experimental stages of development (see box above). Although they are being spurred by the EPA rule, they are unlikely to have significant effects on ULSD production in 2006, however, they may affect the market by 2010. In addition, methods have been developed to produce diesel fuel from natural gas and organic fats, but they still are costly.

NEMS Approach to Diesel Desulfurization Technology

The Petroleum Market Module (PMM) in the National Energy Modeling System (NEMS)⁶⁷ projects petroleum product prices, refining activities, and movements of petroleum into the United States and among domestic regions. In addition, the PMM estimates capacity expansion and fuel consumption in the refining industry. The PMM is also revised on a regular basis to incorporate current regulations that may affect the domestic petroleum market.

The PMM optimizes the operation of petroleum refineries in the United States, including the supply and transportation of crude oil to refineries, the regional processing of these raw materials into petroleum products, and the distribution of petroleum products to meet regional demands. The production of natural gas liquids from gas processing plants is also represented. The essential outputs of the model are product prices, a petroleum supply/demand balance, demands for refinery fuel use, and capacity expansion.

The PMM employs a modified two-stage distillate deep desulfurization process based on proven technologies.¹¹ The first stage consists of a choice of two distinct units, which accept feedstocks of various sulfur contents and desulfurize to a range of 20 to 30 ppm (Table 2): The

---

²⁶NEMS was developed by EIA for mid-term forecasts of U.S. energy markets (currently through 2020). NEMS documentation can be found at web site www.eia.doe.gov/bookshelf/docs.html PMM documentation can be found at web site www.eia.doe.gov/pub/pdf/model_docs/nems/nems_v10p1_20050328.pdf.
¹¹The PMM incorporates the technology database from EnSes Energy & Systems, Inc., a consultant to EIA, for refinery processing modeling.

Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel

9263

Obtained and made public by the Natural Resources Defense Council, March / April 2002
second stage also includes a choice of two processing units, which further deep desulfurize the first-stage streams to a level below 10 ppm. The purpose of reducing the sulfur level to 20 to 30 ppm in the first stage, rather than the common goal of 250 ppm or less, is to enable a more accurate representation of costs for processing streams.

The PMM retains the option of conventional distillate desulfurization when 500 ppm sulfur diesel can still be produced (before June 2010). Because the PMM models an aggregation of refinery capacities in each of the refinery regions, the above representation of multiple processing options is possible, although in reality individual refineries may choose one process over the other on the basis of strategic and economic evaluations.

Individual Refinery Analysis Approach to Diesel Desulfurization Technology

To assess the supply situation during the transition to ULSD in 2006, industry-level cost curves were constructed for this study and matched against assumed demand and imports. The cost curves are the result of a refinery-by-refinery analysis of investment requirements and operating costs for refineries in Petroleum Administration for Defense Districts (PADDs) I through IV. The ULSD production costs were estimated for different groups of refineries based on their size, the sulfur content of the feeds, the fraction of cracked stocks in the feed, the boiling range of the feed, and the fraction of highway diesel produced. The capital and operating costs for the different groups were developed for EIA by the staff of the National Energy Technology Laboratory (NETL).

For the study, a semi-empirical model was developed to size and cost new and retrofitted distillate hydrotreating plants for production of ULSD. Sulfur removal was predicted using a kinetic model tuned to match the limited literature data available on deep distillate desulfurization. Correlations were used in the model to relate hydrogen consumption, utility usage, etc., to the three major constituents of the distillate pool: straight-run distillate, cat-cracker light cycle oil, and coker gas oil. (See Appendix D for a discussion of the assumptions used to construct the model.)

Capital costs ranged from $592 to $1,807 per barrel per day, depending on the size of the unit, whether it was new or retrofitted, and the percentage of straight-run feedstock (Table 3). A large hydrotreater using only straight-run distillate derived from high-sulfur crude had the least cost for both new and retrofitted units. The most expensive units were small hydrotreaters running 32 percent cracked stocks, about the average proportion of cracked feedstocks in PADD II.

| Table 2. Desulfurization Units Represented in the NEMS Petroleum Market Module |
|--------------------------------------|------------------|---------------------------------|-------------------------------|-----------------------------|
| Unit | Capacity (Barrels per Day) | Feedstock | Capital Cost* (1998 Dollars per Barrel per Day) | Total Capital Cost per Unit* (Million 1998 Dollars) |
| HL1/HS2 ... | 25,000 | All except coker gas oil and high-sulfur light cycle oil | 1,331 | 33.3 |
| HD1/H02 ... | 10,000 | All | 1,849 | 18.5 |

*Only on-site costs for hydrotreaters are included in this table. See NEMS documentation for hydrogen and sulfur plant costs. Revamped unit costs are estimated to be 50 percent of new unit costs.

Source: Energy Information Administration, Office of Integrated Analysis and Forecasting.

| Table 3. Range of Hydrotreater Units Represented in the Individual Refinery Analysis |
|--------------------------------------|------------------|---------------------------------|-------------------------------|-----------------------------|
| Type | Throughput (Barrels per Day) | Straight-Run Feedstock (Percentage) | Capital Cost* (1999 Dollars per Daily Barrel) | Total Capital Cost per Unit* (Million 1999 Dollars) |
| New | 50,000 | 100 | 995 | 49.8 |
| New | 10,000 | 68 | 1,807 | 18.1 |
| Revamp | 50,000 | 100 | 1,210 | 99.0 |
| Revamp | 10,000 | 68 | 592 | 29.6 |

*Includes only on-site costs.

Source: National Energy Technology Laboratory.

62Within the PMM, the refinery sector is modeled by a linear programming representation for three refining regions. The first region consists of Petroleum Administration for Defense District (PADD) I; the second of PADD's II, III, and IV; and the third of PADD V. Each model region represents an aggregation of the individual refineries in the region, rather than a rational refinery.
Expected Developments and Cost Improvements

Recent experience indicates that consistent, high-volume production of ULSD is a technologically feasible goal, although many refineries could face major retrofits or new unit construction. The variation in feedstock concerning both sulfur content and the amount of cracked stock may be influential in the choice of process option and the cost of desulfurization, which may also entail a different allocation of streams to products. Although unconventional desulfurization technologies have been promoted recently by various vendors, none has made sufficient progress toward the commercial stage to warrant consideration by most refiners who must start producing ULSD by June 2006.

The two-stage desulfurization process can be accomplished through revamping existing units, building new units, or a combination of both. Several aspects of unit design are important. Properly designed distribution trays can greatly improve desulfurization efficiency, in that catalyst bypassing can make it virtually impossible to produce ULSD. Because hydrogen sulfide (H₂S) inhibits hydrodesulfurization reactions, scrubbing or recycle gas to remove H₂S will improve desulfurization. New design or revamps will also include gas quench to help control temperature through the reactor. In the design of a two-stage system, there will be a hot stripper between the two reactors where ammonia and H₂S are stripped from the first-stage product.

As more commercial evidence and cost information become available for diesel desulfurization in the next few years, it will be possible to better assess the technology choices—including equipment requirements, operating conditions, and production logistics—that most refiners will have to make in order to meet the new ULSD standards. However, the EPA’s tight compliance timetable for producing ULSD might short-circuit the learning process for refiners to acquire necessary experience to make cost-effective decisions.

The many caveats within current vendors’ statements must be carefully scrutinized, to avoid overstating the capability or understating the costs for new or revamped distillate hydrotreating facilities. Most vendors state that their goal is to use or revamp a client refiner’s current process units whenever possible. In trying to reach a 10 ppm or lower sulfur target, however, many units may be unsuitable or require major capital outlays. Uncertainty about the level of revamp is a major source of uncertainty in estimating the cost of the ULSD Rule.

Further consolidation of the refinery industry may achieve better economies of scale, although some industry analysts have expressed concern that a shortage of diesel supply could materialize in the short term if some economically challenged refineries exit the diesel market. Catalyst improvements are expected to be one of the main factors in reducing operating costs, both in terms of recycle rate and efficient use of hydrogen. Other factors, such as the dependence of the refinery on distillates, access to lower-sulfur crude, level of competition, and ability to upgrade infrastructure, must also be taken into account. The European experience could also provide valuable insights for U.S. refineries.

Deployment of Desulfurization Technologies

The deployment of diesel desulfurization technologies will hinge on several factors, such as the ability and willingness of refiners to invest, the timing of investment and permitting, the ability of manufacturers to provide units for all U.S. refineries at once, and the availability of engineering and construction resources.

One impediment to acquiring desulfurization upgrades may be the willingness and ability of individual refiners to obtain capital. The EPA estimates that average investment for diesel desulfurization will cost $50 million per refinery, slightly more than the estimated $44 million per refinery required to meet the Tier 2 gasoline sulfur requirement. Most refiners will invest in the gasoline sulfur upgrade because gasoline is their major product. Because U.S. refineries typically produce three to four times as much gasoline as highway diesel fuel, the per gallon investment cost of ULSD will be three to four times as high.

In its Regulatory Impact Analysis, the EPA provided an analysis of capital requirements indicating that the combined annual capital investment for gasoline and diesel desulfurization would be $2.15 billion in 2004 and $2.49 billion in 2005. The EPA analysis spread the diesel investments over a 2-year period (to reflect "a somewhat more sophisticated schedule for the expenditure of capital throughout a project") and assumed that the gasoline...

---

63 It is believed that, to comply with the new ULSD cap of 15 ppm, a refiner would require about 4 years lead time to secure a permit and to design, build, and optimize a new desulfurization process before commercial production is ready.

64 Small refiners, which may delay ULSD production under special provisions of the Rule, could adopt emerging technologies later in the decade when any of those technologies becomes cost-competitive.


Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel
investments would be incurred in the year before a unit came on line. The EPA concluded that this level of investment should be sustainable by the industry because it is roughly two-thirds of the estimated environmental investments incurred during 1992-1994, when the industry was responding to the 500 ppm highway diesel and oxygenated and reformulated gasoline requirements. Other estimates of ULSD investment costs range from $3 billion to $13 billion (see Chapter 7).

Although not discussed in the EPA’s investment analysis, the 1990s was a period of rationalization for the refining industry, marked by refinery sales, mergers, and closures. Between January 1990 and January 1999, 50 of 205 refineries were closed (4 of which were merged with adjacent refineries).67 The NPC attributes the refinery closures to heightened competitiveness. Although the environmental requirements of the 1990s cannot be pointed to as the cause of the closures, they contributed to the inability of some refineries to compete economically. Refiners who chose not to invest in the 500 ppm sulfur limit (required for highway diesel since 1993) found it more economical to shift their existing high-sulfur diesel production to non-road markets.

Some refineries will be more able than others to obtain capital for Tier 2 gasoline and ULSD projects. Assuming that capital is accessible, a refiner’s willingness to invest in ULSD projects will depend on its assessment of the economics of the market. For instance, a refiner would be less likely to invest if it believed it could not compete favorably with others because the investments would result in a higher cost per gallon. History may lead some refineries to be cautious about investment. In the 1990s refinery upgrades for meeting reformulated gasoline requirements resulted in excess gasoline production capacity. As a result, gasoline margins were depressed, making it difficult for refineries to recoup investments.

Profit margins for ULSD could be depressed if refineries build too much capacity, and the fear of overinvestment could lead some refineries to delay investment until more highway diesel production is required. On the other hand, refineries anticipating inadequate supply of ULSD may choose to invest as early as possible to benefit temporarily from higher margins and sell credits to those that do not invest early. The EPA believes that any lack of investment will be compensated for by the temporary compliance options and credit trading provisions of the ULSD Rule.

Another possible hurdle to the timely adoption of desulfurization technologies is the ability of the engineering and construction industries to design and build diesel hydrotreaters in a timely manner. In addition to providing diesel hydrotreaters, the same contractors will be providing gasoline desulfurization units for the Tier 2 gasoline sulfur reduction requirements that will be phased in between 2004 and 2007. Moreover, engineering and construction requirements will also be expanding outside the United States. The Canadian government has committed to harmonizing gasoline and diesel requirements with the United States. In Europe, refiners will be making upgrades to meet tighter gasoline and diesel requirements in 2005 and have may incentives to produce even cleaner fuels for markets in Germany and the United Kingdom (see discussion in Chapter 6).

In its 2000 study, the NPC provided an analysis of the number of construction projects required for U.S. refineries to provide both gasoline and diesel fuel meeting a 30 ppm sulfur cap. The analysis concluded that “if a-diesel sulfur reduction is required for 2006, implementation would overlap significantly with the Tier 2 Rule gasoline sulfur reduction, and engineering and construction resources will likely be inadequate, resulting in higher costs, implementation delays, and failure to meet the regulatory timelines.” The study also concluded that if a 15 ppm diesel standard is required, further investments in new units will be required and there will be a significant risk of inadequate diesel supplies.

The NPC estimated that 89 refineries will require gasoline hydrosulfurization units by 2004 and that 85 refineries (presumably the same ones) would make upgrades for new highway diesel standards and concluded that if the diesel standard were required within 12 months of completion of Tier 2 gasoline projects, construction labor shortages could occur. The analysis provided peak monthly engineering and construction personnel requirements for five scenarios with different assumptions about the timing and overlap of Tier 2 gasoline and ULSD requirements (Table 4). The scenarios ranged from a “balanced implementation” case, in which one-fourth of the required projects would begin in each quarter of the first year (Scenario A), to highly front-end loaded cases (Scenarios D and E), in which three-fourths of the projects would begin in the first quarter of the first year. Scenarios B and C assumed that refineries would start projects as late as possible.

In the Regulatory Impact Analysis for the ULSD Rule, the EPA conducted its own analysis of the personnel requirements for design and construction services related to the overlapping requirements of the Tier 2 gasoline and ULSD requirements. The analysis provided monthly estimates for each personnel category, assuming that in a given year 25 percent of the projects would be completed per quarter. The monthly estimates were used to develop estimates of the maximum number of personnel required in any given month for the

Tier 2 gasoline program alone and for the gasoline and ULSD programs together, both with and without a temporary compliance option. The estimates of the two programs taken together without the temporary compliance option were about double the employment estimates for the Tier 2 gasoline program only, in all three job categories. When the temporary compliance option is taken into account, personnel requirements for the two programs are only about 30 percent higher than for the Tier 2 gasoline program alone.

Because the largest impact is expected to occur in front-end design, where 30 percent of available U.S. personnel are required, the EPA believes that the engineering and construction workforce can provide the equipment necessary for compliance. It appears that the EPA’s criterion for the adequacy of engineering and construction personnel lies somewhere between 30 percent and 50 percent over the personnel requirements of the Tier 2 requirements alone.

The EPA’s estimates without a temporary compliance option are most consistent with the timing assumptions of NPC’s Scenario A. EPA’s analysis indicates that engineering and construction requirements will be lower given the temporary compliance option of the ULSD Rule; however, NPC Scenarios D and E demonstrate that different assumptions about project timing lead to very different estimates for personnel. The range of personnel estimates shown in Table 4 highlights the uncertainty of the estimates.

The EPA’s analysis assumed that a total of 97 units would be added to make Tier 2 gasoline and that 121 diesel desulfurization units would be added for ULSD (Table 5). The expected startup dates for the gasoline and diesel desulfurization units indicate an overlap of 26 gasoline units and 63 diesel units in 2006. The 2006 overlap in gasoline and diesel startups is noteworthy because it is significantly greater than it would have been with ULSD implementation in any other year except 2004.

Another possible hurdle to implementing technology for the ULSD Rule raised by the NPC is the ability of manufacturers to provide critical equipment. As mentioned earlier, the NPC analysis assumed that a sulfur requirement below 30 ppm would require new deep hydrotreating reactors with reactor pressures in the range of 1,100 to 1,200 psig, requiring thick-walled reactors. As compared with other reactors, the delivery time for thick-walled reactors is longer and the number of suppliers is more limited. Only one or two U.S. companies produce thick-walled reactors, whereas four to six can supply reactors with more typical wall widths. Outside the United States, 10 to 12 companies are able to supply

### Table 4. Estimated Peak Engineering and Construction Labor Requirements for Gasoline and Diesel Desulfurization Projects (Percent of Current Workforce)

<table>
<thead>
<tr>
<th>Analysis Case</th>
<th>Front-End Design Workforce</th>
<th>Detailed Engineering Workforce</th>
<th>Construction Workforce</th>
</tr>
</thead>
<tbody>
<tr>
<td>NPC Scenario A</td>
<td>42</td>
<td>32</td>
<td></td>
</tr>
<tr>
<td>NPC Scenario B</td>
<td>50</td>
<td>48</td>
<td></td>
</tr>
<tr>
<td>NPC Scenario C</td>
<td>56</td>
<td>56</td>
<td></td>
</tr>
<tr>
<td>NPC Scenario D</td>
<td>82</td>
<td>82</td>
<td></td>
</tr>
<tr>
<td>NPC Scenario E</td>
<td>82</td>
<td>82</td>
<td></td>
</tr>
<tr>
<td>EPA With Tier 2 Compliance Option</td>
<td>46</td>
<td>46</td>
<td>10</td>
</tr>
<tr>
<td>EPA With Tier 2 Compliance Option</td>
<td>36</td>
<td>36</td>
<td>10</td>
</tr>
</tbody>
</table>

Source: NPC, National Petroleum Council, U.S. Petroleum Retaining: Assuring the Adequacy and Affordability of Cleaner Fuels, June 2001

### Table 5. EPA Estimates of Desulfurization Unit Startups. 2001-2010

<table>
<thead>
<tr>
<th>Unit Type</th>
<th>2001-2003</th>
<th>2004</th>
<th>2005</th>
<th>2006</th>
<th>2008</th>
<th>2009</th>
</tr>
</thead>
<tbody>
<tr>
<td>New Units</td>
<td>10</td>
<td>3</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>4</td>
</tr>
<tr>
<td>2001-2003</td>
<td>3</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>4</td>
</tr>
<tr>
<td>2004</td>
<td>3</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>4</td>
</tr>
<tr>
<td>2005</td>
<td>3</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>4</td>
</tr>
<tr>
<td>2006</td>
<td>3</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>4</td>
</tr>
<tr>
<td>2008</td>
<td>3</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>4</td>
</tr>
<tr>
<td>2009</td>
<td>3</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>24</td>
<td>4</td>
</tr>
</tbody>
</table>

Source: U.S. Environmental Protection Agency, Regulation Impact Analysis, Heavy-Duty Engine and Vapor Standards and Menu of Options, December 2000, Chapter IV, Table II.B.3

9265
reactors regardless of wall width. This view is at odds with the EPA analysis, which was based on vendor estimates, with reactor pressures in the range of 650 to 900 psig.

Another type of critical equipment identified by the NPC is reciprocating compressors. The NPC indicated that two reciprocating compressors will be required for each diesel desulfurization project. Reciprocating compressors will also be required for gasoline desulfurization projects, and the NPC listed them as the principal constraining factor for the gasoline projects. Excluding the former Soviet Union, there are only five manufacturers of reciprocating compressors in the world. Two are in Europe and were assumed to be occupied with orders for European gasoline sulfur reduction projects through 2003. The NPC analysis did not account for additional orders from Canadian desulfurization projects.

Conclusion

Technology for reduction of sulfur in diesel fuel to 15 ppm is currently available and new technologies are under development that could reduce the cost of desulfurization. Variations in feedstock sulfur content and the amount of cracked stock may be very influential in the choice of process option and cost of desulfurization. Estimates of investment costs related to ULSD production range from $3 billion to $13 billion. The ability and willingness of refiners to invest depends on an assessment of market economics. Experience with upgrades to meet reformulated gasoline requirements in the early 1990s may lead some refiners to be cautious. The availability of personnel, thick-walled reactors, and reciprocating compressors may delay some construction.
4. Impact of the ULSD Rule on Oil Pipelines

Introduction

The petroleum products pipeline distribution system is the primary means of transporting diesel fuel and other liquid petroleum products within the United States. The Nation’s refined petroleum products pipeline system is not monolithic. Pipelines are distinguished by the region they serve, the type of service they offer, their mode of operation, their size, the size of the interfaces between batches, and how they dispose of them. In preparing this report, several pipeline companies were contacted. These companies represent a cross-section of size, capacity, location, markets, corporate structures, and operating modes. The assessment of the impact of the ultra-low-sulfur diesel (ULSD) Rule is complex, both because the pipeline system is complex and because there are uncertainties that cannot be resolved without operating experience with ULSD.

The first question appears to be: “Can the Nation’s oil pipeline system successfully distribute ULSD without degrading its sulfur concentration?” While the answer seems to be yes, lingering uncertainties that come with the unique specifications of this new and untested product prevent a clear assertion. Among the uncertainties are the following:

- Protecting the product integrity of 15 parts per million (ppm) product will be more difficult than protecting the product integrity of the current 300 ppm highway diesel. Not only is the sulfur specification lower, with less room for error, but also the relative “potency” of the sulfur in products further upstream is higher.

- The behavior of sulfur molecules in ULSD has not been field-tested to allow conclusions about whether pipeline wall contamination is a real problem or simply a fear, and whether the migration of sulfur will require a significant increase in the volume downgraded at the interface.

- There are few pieces of the approved test equipment now in use, but its reliability and accuracy are unproven.

Although the overall costs of the program may be lower if the rule is phased in, the incremental costs associated with temporarily transporting ULSD, in addition to low-sulfur diesel and heating oil fall on pipelines and other players in downstream distribution. During the transition phase, some 20 percent of the highway diesel volume will be 500 ppm. The increased cost of tankage for handling this small volume of 500 ppm material is borne solely by the affected regions. On a cost-per-gallon basis for the small volume in the limited region, the increased cost more than doubles the current pipeline tariff for the largest carriers. Whether such an increase can be passed through in tariff rates is a matter of significant concern for pipeline operators.

Finally, there is a concern that further limitations on distribution flexibility will contribute to price spikes or spot outages. The distribution of ULSD will reduce the system’s flexibility by imposing testing requirements that will increase transit times by increasing the product lost to downgrade and by “freezing” storage capacity in the event of product contamination. These adverse impacts inject new supply risks into the system, making an already burdened oil distribution system more vulnerable to product supply imbalances in local and regional markets. Supply imbalances, if they occur, could cause increased product price volatility, price spikes, and product outages. This concern is not just theoretical. During 2000, logistics problems contributed to large and sudden price spikes in the Midwest gasoline market. To the extent that the system is overburdened, stresses and unforeseen circumstances will cause imbalances more often, and with greater impact.

The Role of Refined Petroleum Product Pipelines

Oil pipelines transport more crude oil and refined petroleum products in the United States than any other means of transportation. Typically, as common carriers (which transport for any shipper on a nondiscriminatory basis), oil pipelines are subject to State authority.

---

Energy Information Administration / Transition to Ultra-Low Sulfur Diesel Fuel

9266

Obtained and made public by the Natural Resources Defense Council, March / April 2002
they are in intrastate service, or to the U.S. Department of Transportation for operations and safety and to the Federal Energy Regulatory Commission for tariff rates, if they provide interstate service. Interstate pipeline carriers transport the higher volume, by far. Accordingly, the Federal Government is the major regulator of oil pipelines. Some pipelines are private, serving private (proprietary) transportation needs. These private oil pipelines are not regulated with respect to tariff rates or other economic issues. Today, transportation of refined petroleum products by pipeline is essential to move more than 19 million barrels per day of refined petroleum products to markets throughout the Nation.

The United States is divided into five Petroleum Administration for Defense Districts (PADDs), each with distinct population levels, indigenous oil production, refinery and pipeline systems, and crude oil and refined product flows. Imbalances that result from these different characteristics are brought into equilibrium by trade and hence transportation. The trade can consist of imports from abroad and shipments from other regions. Shipments from the Gulf Coast (PADD III) dominate (Figure 1), first to the East Coast (PADD I) and second to the Midwest (PADD II). Shipments from the East Coast to the Midwest are third. Thus, shipments between PADDs east of the Rockies account for almost all the interregional trade. Intraregional movements are also a core element in the market logistics, but few data are available on these movements. (See Appendix C for a more detailed discussion of the U.S. regions and their key pipelines.)

Overview of Key Pipeline Operations

Refined petroleum product pipelines in the United States fall into two service categories. Trunk lines serve high-volume, long-haul transportation requirements; delivering pipelines transport smaller volumes over shorter distances to final market areas. As the system reaches its furthest capillaries, the inflexibilities imposed by the smaller scale become more apparent. A “lockout” can occur when a terminal does not have room to accept a scheduled shipment and there are no other terminals at hand to accept the product. The pipeline is thus stalled until the product can be delivered.

Petroleum product pipelines also differ by whether they operate on a batch or fungible basis. In batch operations, a specific volume of refined petroleum products is accepted for shipment. The identity of the material shipped is maintained throughout the transportation process, and the same material that was accepted for shipment at the origin is delivered at the destination. In fungible operations, the carrier does not deliver the same batch of material that is presented at the origin location for shipment. Rather, the pipeline carrier delivers material that has the same product specifications but is not the original material.

In general, fungible product operation is more efficient; however, customer requirements for segregation limit fungible operation, and batch service is often the only feasible choice. Like the difference between trunk and delivering carriers, the difference between fungible and batch service is one of scale for many operating parameters. An oil pipeline in batch service has considerably less flexibility to offset operating “hiccups” (such as product contamination at a shipper’s terminal tank) than does an oil pipeline operating in fungible service.

Product pipelines routinely transport various grades of motor gasoline, diesel fuel, and aircraft turbine fuel in the same physical pipeline. (For the most part, oil pipelines do not transport both crude oil and refined petroleum products in the same pipeline.) To carry multiple products or grades in the same pipeline, different petroleum products or grades are held in separate storage facilities at the origin of a pipeline and are delivered into separate storage facilities at the destination. The different types or grades of petroleum product are transported sequentially through the pipeline. While traversing the pipeline, a given refined product occupies the pipeline as a single batch of material. At the end of a given batch, another batch of material, a different petroleum product, follows. A 25,000-barrel batch of product occupies nearly 50 miles of a 10-inch diameter pipeline.

Generally, such batches are butted directly against each other, without any means or devices to separate them. At the interface of two batches in a pipeline, some (but relatively little) mixing occurs. As a guide to understanding the volume of interface generated, it would be typical for 150 barrels of mixed material (“transmix”) to be generated in a 10-inch pipeline over a shipment distance of 100 miles. The hydraulic flow in a pipeline is also a crucial determinant of the amount of mixing that occurs. “Turbulent flow,” as occurs in most pipelines, minimizes the generation of interface. Operations that require the flow to stop and start generate the most interface material.

The composition of the mixed (or interface) material reflects the two materials from which it is derived. While it does not conform to any standard petroleum product specification or composition, it is not lost or wasted. For interface material resulting from adjacent batches of different grades of the same product, such as mid-grade and regular gasoline, the mixture typically is blended into the lower grade. This “downgrading” reduces the volume of the higher quality product and increases the volume of the lower quality product.

Typically, refined oil products are transported from a source location, such as a refinery or bulk terminal, to a distribution terminal near a market area. Large
Figure 1. Pipeline Shipments of Distillate Fuels Between PADDs, 1999

Note: Includes low-sulfur (highway) diesel fuel and high-sulfur distillate fuel oil (non-road diesel fuel and heating oil).

aboveground storage tanks at an origin location accumulate and hold a given petroleum product pending its entry into the pipeline for transport. Petroleum products are also stored temporarily in aboveground storage tanks at destination terminals. Such tanks usually are dedicated to holding a single petroleum product or grade. Most storage tanks used in pipeline operation are filled and drained up to four or more times per month.

In addition to the minor creation of interface material that occurs in pipeline transit, creation of interface material also occurs in the local piping facilities (station piping) that direct petroleum products from and to respective origin and destination storage tanks and in the tanks themselves. Essentially, station piping represents the connection between a main pipeline segment and its requisite operating tanks. The concept is simple in theory, but in practice the configuration of station piping is not. Station piping layouts become more complex as the tanks at a pipeline terminal facility become more numerous.

The interface generation in station piping and breakout tanks may be even more important than during pipeline transit. The volume of interface material thus generated is due to the physical attributes of the system. It has fewer variables but approaches a fixed value on a barrel-per-batch, not a percentage, basis. For instance, one pipeline operator creates 25,000 barrels of high-sulfur/low-sulfur distillate interface per batch whether the batch is 250,000 barrels or 1,000,000 barrels. In addition, a given batch of product might be transported in multiple pipelines between its origin and its final destination and even within the same system might require a stop in breakout tanks, as noted above. Each segment of the journey generates additional interface.

Challenges of the ULSD Rule

Because pipeline operators do not have experience with 15 ppm product, there are significant uncertainties related to its transport. This section discusses some of the issues:

- The volume of downgraded product likely to be produced from deep pipeline cuts necessary to preserve the integrity of ULSD
- Likely strategies for protecting the product integrity of 15 ppm diesel and their impact on the generation of interfaces and transmix
- Limitations on downgrading from 15 ppm to 500 ppm product within the diesel pool
• The sulfur content of products reprocessed from transmix
• The possibility that residual sulfur adhering to main-line pipeline walls may contaminate ULSD as it transits the pipeline
• Product testing
• The challenges and costs of the phase-in period.

Estimation of Interface Generation

The U.S. Environmental Protection Agency (EPA) estimates that the interface that will be generated under the ULSD rule will be 4.4 percent of the highway diesel fuel volume transported by pipeline. EPA arrived at this 4.4 percent figure by estimating the current level of interface as a percentage of highway diesel fuel volume and doubling the current level.71 There are significant uncertainties in the EPA's calculation.

At the EPA's request, the Association of Oil Pipelines (AOPL) and the American Petroleum Institute's pipeline Committee surveyed their members on the impact of the ULSD rule. The survey and its cover letter are comments to the EPA's Notice of Proposed Rulemaking.72 AOPL points out that pipeline companies do not now separately account for interface volumes and indicated that the estimates of downgraded interface from the survey should not be used for economic analysis.73

Six respondents provided numerical estimates of the current diesel fuel downgrade. These estimates ranged from 0.2 percent to 10.2 percent of diesel shipped by the pipeline on an annual basis. In making its calculation of the total current downgrade of highway diesel, the EPA used the range of downgrade percentages from the AOPL survey and information from a database on the pipeline distribution system published by PennWell.

The EPA assigned each pipeline diameter in the PennWell database a value between 0.2 percent and 10.2 percent (the range of response in the AOPL survey), with the smallest diameter at the low end and the largest at the high end. EPA then multiplied the assigned values by the miles of a given diameter of pipe and divided the result by the total number of pipeline miles in the database to arrive at an average downgrade of 2.5 percent.

Pipeline diameter is only one of the factors in determining the amount of interface material. The velocity of the flow and the topography of the land are also important factors. A pipeline that can run in a turbulent flow will have a lower volume of interface for a given diameter than one in which the flow slackens for any number of operating reasons. Interface generation is also affected by batch size. Moreover, station piping and breakout tanks are additional and large generators of downgrade volume. (The EPA accounted for the role of station piping and breakout tanks by assigning higher percentages to the larger diameter pipe, as a proxy for the greater complexity of the large systems.) In addition, the higher product flow in the larger lines is not taken into account.

If a system like the Colonial Pipeline has a downgrade rate of 10 percent, it would result in a much higher number of downgraded barrels than an 8-inch-diameter line. In the AOPL's submission, the operator with the 10-percent downgrade accounted for 90 percent of all downgrade.

EPA then adjusted its initial estimate of downgrade volumes downward by 15 percent. EPA made this adjustment based on the following assumption:

Data from the Energy Information Administration (EIA) indicates that 85 percent of all highway diesel fuel supplied in the United States is sold for resale. Therefore, we believe it is reasonable to assume that only this 85 percent is shipped by pipeline, with the remaining 15 percent being sold directly from the refiner rack or through other means that does not necessitate the use of the common fuel distribution system. By multiplying 2.5 percent by 0.85 we arrived at an estimate of the current amount of highway diesel fuel that is downgraded today to a lower value product of 2.2 percent of the total volume of highway diesel fuel supplied.74

This downward adjustment of downgrade volumes has some limitations. EIA's Form 782A collects data from refineries. There is no way to determine whether the volumes sold to end users transit a pipeline or not. They may have, if they were sold in a refiner's integrated system. Form EIA-782A excludes sales to other refineries, and some of the excluded volumes may also have been transported in a pipeline. Finally, the volume throughput in a pipeline system is not necessarily equal to consumption, because some volumes may travel in more than one pipeline before reaching the consumer. Thus, "sales for resale" as a share of total refiner sales is not an ideal proxy for the share of highway diesel transported by pipeline.

72 "Cited in the EPA's documents as "Comments of Association of Oil Pipelines (AOPL) on the NPRM, Docket Item IV-D325."
73 AOPL Comments, p. 2.
The EPA assumed the level ULSD downgrade volumes at 4.4 percent of ULSD supplied, double their current estimate of 2.2 percent of highway diesel supplied. The EPA based this assumption in part on comments made by respondents to the AOPL survey. In its Regulatory Impact Analysis, the EPA stated a desire to "... yield a conservatively high estimate of our program's impact..." and noted "... an appropriate level of confidence that we are not underestimating the impact of our sulfur program... will help account for various unknowns that may cause downgrade volumes to increase." 75

Pipeline operators have several concerns about the downgrade volume of ULSD. One concern is that the simple use of specific gravity—the current method—may not be a sufficiently sensitive indicator to make the interface cut. One of the AOPL/API survey respondents noted, for instance: "Our initial studies of tailback from [heating oil] to [low-sulfur diesel] indicates that tailback in interfaces to ULSD diesel may be as much as 4 times that of the gravity change between products." 76 However, the EPA viewed increased tailback from heating oil to ULSD as less of a concern. 77

The EPA assumed that pipeline operators would not have to substantially change their current methods to detect the interface between ULSD and adjacent products in the pipeline. In the EPA's view it was highly unlikely that there would be any difference in the physical properties of ULSD versus the current 500 ppm highway diesel that would cause a substantial change in the tailback of sulfur from preceding batches into batches of ULSD. 78

Another concern is that a protective cut, when it can be calibrated using real-world experience, may require a large volume downgrade. The conventional approach is to buffer distillate products against other distillate products to facilitate blending, as noted in the previous discussion. A batch of 500 ppm diesel might be wrapped between a batch of 2,000 ppm jet fuel and a batch of dye non-road distillate fuel oil (heating oil) at 3,000 to 5,000 ppm. Thus, the product with the sulfur restriction (500 ppm diesel) is wrapped by a product with four times the sulfur (2,000 ppm jet fuel), and by a product with six to eight times the sulfur (3,000 to 5,000 ppm heating oil). In practice, the current highway diesel is usually considerably less than the 500 ppm limitation (300 ppm would not be uncommon). Under these circumstances, it is relatively unlikely that chance contamination could move the diesel from 300 ppm to nonconforming status at more than 500 ppm.

The current situation, however, contrasts significantly to the ULSD situation. ULSD (15 ppm) may be adjacent to jet fuel at 2,000 ppm, 133 times the ULSD sulfur concentration, or to heating oil at 3,000 to 5,000 ppm, 200 to 300 times the ULSD concentration. In this case, a tiny contamination will move the ULSD batch to nonconforming status. According to one of the AOPL/API respondents, "... a 0.15 percent contamination (15 bbls in 10,000 bbls) of [heating oil] in ULSD will raise the sulfur level by 3 ppm..." According to another, "... the [heating oil] at 2000 ppm can contaminate the ULSD at levels as low as 0.22 percent." 79 In combination with the concerns raised about the sulfur tailback, the issue of the volume necessary for the protective cut is another significant uncertainty in the handling of ULSD.

The assumption made about the size of the increase in interface generated after a switch from the current standard for highway diesel (500 ppm) to ULSD becomes important when calculating the cost of the regulation. EPA's estimate of additional costs of the ULSD rule that can be attributed to increased product downgrades was 0.3 cents per gallon of ULSD supplied once the ULSD rule was fully implemented and all highway diesel must meet the 15 ppm standard. This 0.3 cents per gallon was with the 4.4 percent downgrade assumption. Turner Mason and Company conducted a study of distribution costs for the API and came up with a cost increase of 0.9 cents per gallon for product downgrade. Turner Mason assumed that 17.5 percent of ULSD shipped would be downgraded.

Strategies for Buffering ULSD in a Pipeline

Because there is no experience with distributing ULSD in a non-dedicated or common transportation system, pipeline operators are unsure how they will sequence the new product in the pipeline. Those that now ship highway diesel adjacent to jet fuel are unlikely to be able to continue the practice unless the sulfur content of the jet fuel is also lowered. At the current jet fuel sulfur content, ULSD cannot tolerate the contamination from the protective cut necessary to protect the other properties

76 AOPL Comments, Attachment, p. 2
79 AOPL Comments, Attachment, p. 2 and p. 5.
9268

Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel

Obtained and made public by the Natural Resources Defense Council, March / April 2002
of the jet fuel. According to the EPA, pipelines might have to treat a mixture of jet fuel and 15 ppm diesel as transmix in separate tanks, because it will not be acceptable either as jet fuel or as 15 ppm diesel. The need for new tanks to handle this new hybrid, however, would be difficult to accommodate. In addition, it is not clear how the hybrid would be reprocessed for reentry into the petroleum products distribution system.

There is currently no regulatory requirement that the sulfur content of jet fuel be lowered to 15 ppm. Even kerosene/jet fuel used for blending into 15 ppm diesel is controlled by the specification of the finished product, not the blending component. As a practical matter, however, any kerosene/jet fuel destined for blending must have ultra-low sulfur content. Whether an ultra-low-sulfur jet fuel will present additional lubricity problems for jet engines is another unknown.

While there is a 500 ppm product in use, operators might be able to buffer 15 ppm ULSD with the 500 ppm product. Such buffering is limited by the volumes that can be downgraded within the diesel pool, however, as discussed below.

Gasoline, at an average of 30 ppm and a maximum of 80 ppm, will represent the next lower sulfur content in the overall product transportation slate. Some operators have speculated that if the trailback is significant, gasoline buffers might be the best alternative. There are considerable problems, however, with the increased generation of transmix. The availability of reprocessing facilities is the first. In addition, some transmix is now reprocessed in purpose-built facilities—a simple distillation column—on station property. Such a simple facility, or even a more complex purpose-built facility, has never needed to accommodate desulfurization. Thus, the reprocessing of transmix will be routinely more difficult under the ULSD program, and it is unclear that the facilities will exist to reprocess increased volumes of transmix.

Pipeline operators will establish interface minimization strategies on a case-by-case basis. Trunk line operators will seek to ship ULSD in as large a batch as possible. Delivery pipeline operators will do the same, but with more difficulty, because delivery pipelines ship smaller volumes and face more operating permutations related to time and location requirements. Operators of fungible pipeline systems will have an advantage in protecting the integrity of ULSD in transit and minimizing the expense of downgrading. It is worthwhile to note that the use of large batches requires more careful inventory management on the part of pipelines and shippers, to assure that requisite tanks have room for the incoming product. Given the inventory environment in oil markets, any new rigidity imposed by the logistics system can reverberate through market prices.

The result of deeper cuts will be significantly more product downgrading. The practical effect of creating a greater volume of high-sulfur distillate is difficult to estimate. Depending on market circumstances at various locations, it will range from none to significant. The worst case will be found where the creation of high-sulfur distillate affects terminals that do not have capacity to accept and store the material or in markets that do not have enough demand to absorb it.

The 20-Percent Downgrade Rule

The ULSD Rule prohibits any party downstream of the refiner or importer from downgrading more than 20 percent of its annual volume of 15 ppm highway diesel to 500 ppm highway diesel. 81 (There is no limitation on downgrading from 15 ppm diesel to the non-road pool.) This provision is designed to discourage downgrading within the diesel pool during the phase-in period. 82 The pipeline industry, however, is likely to be handling significantly increased volumes of downgraded material and to have substantial incentive to minimize the downgrade, because of the economic penalty involved. Furthermore, the downgrade limitation applies to normal interfaces.

As noted previously, the generation of some interface is irreducible, fixed by the physical attributes of the system. An operator with a high-interface system may have little room against the 20-percent limitation when all the other increases in ULSD interface are factored in. The 20-percent limitation also applies to the accidental contamination of a batch. If a batch were accidentally contaminated on a high-interface system, the operator might be required to deny that product to the diesel pool, even though it met all the specifications for 500 ppm material. Chances of localized diesel fuel supply imbalances are increased, and with them, the possibility that a system could get "frozen" by nonconforming product.

Given the uncertainties surrounding the transport of ULSD, the 20-percent downgrade rule will be particularly difficult when the first batches of ULSD are transported. There may be multiple contaminated batches before operating norms are established and equipment is calibrated.


Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel

9268A

Obtained and made public by the Natural Resources Defense Council, March / April 2002
Residual Sulfur in a Pipeline

In comments on the proposed ULSD Rule, pipeline operators raised a concern over whether residual sulfur from high-sulfur material could contaminate subsequent pipeline material beyond the interface. The concern was based on limited experience. Recently, in light of the prospect of transporting ULSD, Buckeye Pipe Line conducted a test of possible sulfur contamination from one product batch to another. In the test on one segment of its pipeline system, Buckeye made a careful measurement of sulfur content in batches of highway diesel fuel following a batch of high-sulfur diesel fuel. Buckeye found that the sulfur content of the second batch of highway diesel fuel increased. However, the EPA stated: "We believe there is no reason to surmise that contamination from surface accumulation will represent a significant concern under our sulfur program." This issue cannot be resolved without further testing. Until it is, it will remain an uncertainty about the impact of the ULSD Rule.

Product Testing

Product testing is another area of considerable concern for those involved in the transport of highway diesel fuel, for two reasons: (1) The designated test method was developed for testing sulfur in aromatics and has not yet been adapted or evaluated by industry as a test for sulfur in diesel fuel. (2) There is no readily available and appropriate test for sulfur that will permit the precise interface cuts between batches that will be required in handling ULSD. The first of these issues is important for all players in ULSD markets, and the second is specific to the oil pipelines that will transport ULSD.

Currently, oil pipeline operators test the petroleum products they transport in a variety of ways, for a variety of parameters. Each product has its own relevant test parameters, and grades of a particular product are tested to confirm their defining characteristics within a product group. In many pipelines, product batches are tested four times at various stages of their entry to or transit through the pipeline:

- Rigorous testing is performed before products enter a pipeline to assure that relevant specifications are within the normal range.
- Many pipelines monitor materials at strategic pipeline locations en route for contamination.

At or near a product's delivery point, pipelines perform oversight testing covering a limited number of key product parameters (but not sulfur content).

Most pipelines test random pipeline batches using a full battery of tests.

All tests except in-line testing, the second testing regime outlined above, are performed on a batch basis. All but the fourth testing regime outlined above are performed on each batch of products. Pipeline operators are equipped at their own pumping and delivery stations to perform oversight testing on an expedient, on-site basis. Other batch testing is typically performed at an off-site laboratory. Some operators use test laboratories owned and operated internally and some use third-party laboratories. The large laboratories, whether operated by a pipeline operator or by a third party, will be able to meet any testing requirements. However, the designated test method presents uncertainties even to the most sophisticated laboratories, as discussed more fully below. ULSD regulations on testing apply directly only to refiners and importers, leaving additional leeway for parties downstream to choose a test method. Thus, the concerns with respect to test method apply even more strongly to refineries and importers than to pipelines and other downstream parties.

The designated testing method will be ASTM 6428-99, not the widely-used ASTM 3453-99, which has been approved by the State of California and has been demonstrated to be reliable in testing very low sulfur content. The designated method, ASTM 6428-99, was developed for testing sulfur in aromatics. There is no currently available test methodology to apply the test to sulfur in diesel fuel. Because the diesel methodology has not yet been developed for the designated method, it has not yet been tested by multiple laboratories. By industry convention, new test methods are subjected to "round robin" testing under the oversight of the American Society of Testing and Materials (ASTM), in which multiple laboratories apply the test method to multiple batches to develop an objective evaluation of the method's reliability and accuracy. The correlation of the round robin's results becomes the industry standard and is used to calibrate other test methods against the designated method. The correlation is critical to the choice of test method and equipment for downstream players.

While ASTM 3453-99 has been designated as an alternative test method, its results must be correlated with the

---

83 Operators at Explorer Pipeline, which formerly carried crude oil and refined products as batches in the same pipeline, also observed that refined products following high sulfur crude oil in the pipeline experienced a material increase in sulfur content. (The physical characteristics of crude oil are distinct from refined products, and its sulfur content can be considerably higher than the sulfur content of refined petroleum products shipped in a pipeline.)


Upon entrance to a pipeline, distillate fuels are given a full battery of tests, typically examining approximately 18 separate parameters. In an oversight test for distillate fuels, products are tested for flash point, specific gravity, and appearance. With respect to highway diesel fuel, sulfur content is also analyzed. Other tests relevant to distillate fuels, such as cetane, cloud point, freeze point, or corrosiveness, are performed at an off-site laboratory.

The same rigorous level of testing is performed that is randomly applied to other products on a sampling basis. The sulfur content of existing highway diesel fuel is often well under the 500 ppm specification. It is not uncommon for highway diesel to contain only 200 ppm sulfur. Thus, the statistical reproducibility of sulfur testing can comfortably be more than 20 to 50 ppm, and is Operators anticipate that sulfur testing of ULSD will have to work within a 3 to 5 ppm reproducibility error.

With a 3 to 5 ppm reproducibility in the test, a product could be tested at 10 ppm as it enters the system and at 15 ppm as it exits. Generally, pipeline operators do not have a consensus on the sulfur content they will require as the product enters the pipeline system. Some have mentioned levels as low as 7 to 8 ppm in order to...
leave room for test reproducibility and unavoidable contamination.

Currently, most oil pipeline operators use X-ray fluorescent sulfur analyzers such as those manufactured by Oxford Instruments, Asoma Instruments, or Horiba, Ltd., for oversight sulfur content testing of highway diesel fuel. These analyzers, however, will be unable to monitor ULSD. Some oil pipelines use Antek Instruments, administering ASTM 5453-99 in a laboratory to monitor sulfur content on a batch basis. However, this equipment and test will help with the interface cut only in some situations, because its application for in-line testing presents a number of challenges (see below).

Some oil pipelines use in-line testing equipment to detect contamination close to and downstream from potential source locations where foreign or off-specification material might be inadvertently introduced into pure material (Figure 2). Early detection of contamination gives operators flexibility in correcting problems before they become intractable. However, there is no in-line test for sulfur content.

Product testing is different from instrumented detection of specific gravity, which is used to identify and track product batches in a pipeline system. Batch tracking and identification are accomplished by in-line monitoring of the pipeline stream’s specific gravity at strategic pipeline locations. Such locations are typically station entry points or other locations where batches need to be “cut” and separately directed to subsequent pipeline segments in a system or to storage tanks for segregation (Figure 3). The cut, as noted previously, does not depend on sulfur content.

Most oil pipeline operators will probably want or need to perform in-line monitoring of sulfur content, because degradation of ULSD will easily and, possibly, frequently occur. The entry, for example, of only 35 barrels of heating oil (3,000 ppm) into a 10,000-barrel batch of ULSD will contaminate the batch. A 10-inch diameter pipeline flowing at 4 miles per hour (a representative rate for a delivering carrier) is flowing at some 34 barrels per minute. Other carriers may be flowing faster, and on larger diameter pipelines, are moving more product. Hence, flow rates can exceed 300 barrels per minute. The 35-barrel contamination, then, is quick to occur. A normal cut, illustrated above, might take some minutes.

In-line testing for sulfur will represent a difficult challenge for the oil pipeline industry and for test instrument manufacturers. Current in-line instruments such as flash point or dye/haze analyzers cost $40,000 each to acquire, but there is no similar instrument available to meet ULSD test requirements. Current instruments for testing sulfur do not have adequate sensitivity, accuracy, or speed.

Figure 3. Monitoring Pipeline Batch Change

![Graph showing pipeline batch change](image)

**Note:** The screen capture originating from the pipeline's SCADA system illustrates a normal batch change from baseline to AP, showing an increase in AP gravity and 128 minimum flashpoint.

\[977 \times 9.965 + 935 \times (35 \times 0.000) / 10,000 = 17.5 \text{ ppm}

Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel

9270

Obtained and made public by the Natural Resources Defense Council, March / April 2002
With respect to speed of analysis alone there is a significant performance deficiency with current in-line analysis techniques. Current machines require 5 to 10 minutes to complete one analysis of a passing product stream. Five minutes is far too long to permit a pipeline operator to make a correctional response if off-specification material is detected in a batch of ULSD. One suggested solution would move the testing equipment to an upstream (earlier) location. The pipeline could construct a test loop, fed by samples from the main line. Samples regularly extracted from the product stream could flow through the loop to the test equipment housed in a shed, and readouts of the results could be returned to controllers to identify the interface as the product approaches.

Operators point to a number of difficulties with such an upstream testing mechanism. According to industry experts, many refineries test the sulfur content of outgoing product using ASTM 5453-99 with such a test loop, and at least one major pipeline system uses ASTM 5453-99 with an upstream test loop, so it is clearly an effective alternative for some applications. Refineries may have more success using the ASTM 5453-99 with a test loop, because product flow is slower in refinery piping than in oil pipelines, and the speed of the product flow dictates the placement of the test loop. For example, such a loop would have to be positioned far enough upstream to allow the sample flow to reach the test equipment, perform the test, and return the readout in time to make the batch cut. If the loop transit and testing took 5 minutes, for instance, and the product flowed through the pipeline at 8 miles per hour, the equipment would have to be positioned about two-thirds of a mile upstream of the valve. This distance would commonly be outside of a station property, on the right-of-way.

Although positioning certain equipment upstream is a relatively common pipeline practice, restrictions on the use of or availability of space on the right-of-way would be among the factors that could be obstacles to positioning anything as substantial as a free-standing shed on the pipeline right-of-way. Power and communications availability on the right-of-way could also be impediments. The expense of the equipment is an additional deterrent to placing equipment in an unstaffed remote location. Finally, an oil pipeline with many delivery points—a delivering carrier might have 100, for example—would find it prohibitively expensive to install such equipment at each delivery location.

**Special Issues Related to the Phase-In**

The temporary compliance option as well as the provisions related to small refineries provide flexibility for refiners and importers to phase in ULSD, at the expense of pipelines and other downstream distributors. The phase-in provision assumes that some operators carry an additional grade of diesel/distillate fuel oil during the transition years, providing concomitant facilities for segregating the product. As noted earlier, the East Coast is the only region where operators consistently carry both diesel, at 500 ppm, and heating oil, at 3,000 to 5,000 ppm. Many pipelines carry only 500 ppm product, serving both highway and non-road needs with the same fungible grade (dye is added at the destination terminal). Most also carry jet fuel. The ULSD phase-in will push them to carry an additional grade of distillate fuel oil—diesel at 15 ppm—in addition to diesel at 500 ppm and, for some, heating oil at 3,000 to 5,000 ppm plus jet fuel.

Tank size and utilization have been optimized at most terminals to carry the existing product slate. Pipeline executives are universal and adamant in their opinion that sufficient storage tanks and other pipeline assets are not available in most pipeline systems to segregate a third grade of distillate. Many small terminals are unable to add tanks because of space and permitting concerns, and even at larger terminals such constraints may be a factor. Permits can take years to obtain. For terminals that are able add tanks, new tanks cost $1 million or more each, an expenditure that is necessary only to carry a discrete product for a limited period of time. In addition, because of the limited volumes involved, the tanks may be used inefficiently during the ULSD transition period.

The EPA estimated that there are 853 terminals, excluding tanks at refineries, that carry highway diesel. The EPA assumed that, of these 853 terminals, 40 percent would build a new tank to distribute both 15 ppm and 500 ppm diesel fuel during the transition period. At a cost of $1 million per new tank, the additional cost of new terminal tankage was estimated to be approximately $340 million.

Beyond the terminal level, the EPA estimated there are 9,200 "bulk plants" that carry highway diesel fuel, excluding tanks at refineries. Again, the EPA assumed that 40 percent of these bulk plants would build a new tank to accommodate both 500 ppm and 15 ppm diesel fuel. The EPA assumed a cost of $125,000 for each of these smaller tanks, giving a total cost of new tankage at the bulk plant level of $460 million.

Finally, at the truck stop level, the EPA assumed there are 4,800 truck stops operating in the United States, of which 50 percent would sell both 500 ppm and 15 ppm...
diesel fuel. The EPA cited a survey on the expected cost of handling a second grade of diesel fuel by the National Association of Truck Stop Operators of its members. Based on this survey, the EPA estimated an average cost of $100,000 per truck stop to handle the two diesel grades, giving a total of $240 million. A Petroleum Marketers Association of America estimate gave costs of $50,000 per truck stop. The total costs of new tanks and equipment to handle both 500 ppm and 15 ppm diesel fuel were estimated by the EPA at $1.05 billion.

The EPA estimated the total cost per gallon of highway diesel of additional storage tanks at 0.7 cents. This 0.7 cents per gallon additional cost was for the 2006 to 2010 phase-in period. The EPA assumed that the additional storage tanks would be fully amortized during the phase-in period, and that service stations supplying light-duty vehicles with diesel fuel, centrally fueled fleet facilities, and card locks (unattended filling stations) would not install additional storage tanks to handle both 500 ppm diesel and ULSD. Therefore, no cost was estimated for additional storage tanks during the phase-in at service stations, centrally fueled fleet facilities, or card locks.

Where an operator cannot add a tank, it may choose to drop a grade of product. (Such a strategy is not a clear winner, however, because a dropped grade of gasoline, for instance, requires the shipment and storage of greater volumes of another grade of gasoline to compensate.) A carrier might be able to drop a grade of distillate fuel oil, but not without requiring an additional, compensating volume of low-sulfur product or ULSD to meet the market need, exacerbating the draw on refiner capabilities.

The question of whether pipeline companies will be able to recover the increased costs associated either with moving ULSD or moving ULSD plus another temporary grade is a matter of conjecture. The only process for recovery will be tariff rates, and the path to structuring rates to allow that recovery is uncharted.

Overview of Tariff Rate Issues

The majority of transportation for refined petroleum products by volume or by barrel-miles is provided by common-carrier oil pipelines operating in interstate service, under rates regulated by the Federal Energy Regulatory Commission (FERC). Most oil pipeline carriers have approved tariff rates on file with the FERC covering the transportation of diesel fuel. If no other application or action were taken by an oil pipeline company, the existing tariff rates covering diesel fuel would apply to ULSD when that material is distributed to markets. As noted in other sections of this report, however, oil pipelines will incur large, incremental capital and operating costs in distributing the new diesel fuel.

For most regulated oil pipelines, the FERC uses an economic index as the basis for approving tariff rate increases. The index provides that tariff rates may increase without challenge by a percentage amount no more than the Producer Price Increase for Finished Goods, less 1 percent over an approved base rate. If an oil pipeline carrier is operating under the FERC's index method and applies its existing tariff rate to ULSD, there will be no basis for the carrier to recover its extraordinary incremental costs in the approved rate.

Some oil pipeline companies operate under alternative programs with the FERC. The second most prominent method is to administer some or all of a carrier's tariff rates under a market-based system. Under this method, if various markets served by an oil pipeline are first found by the FERC to be workably competitive, the FERC then stipulates the basis by which the pipeline carrier may raise rates more flexibly, without application of the index. Many oil pipeline operators believe that market conditions under which they operate are far more competitive than their status as regulated utilities suggest. If they are correct (and the FERC's own findings of workable competition in many oil transportation markets suggests that they are), pipelines will be competitively constrained from simply passing through their higher ULSD costs to shippers.

A carrier might file a new tariff rate expressly covering ULSD. If that rate is greater than the previous rate (or the remaining tariff rate for other grades of diesel fuel), the FERC or a shipper might protest the new rate, a common occurrence. In such an event, it is possible that the new tariff rate would not be permitted to take effect or that it would be accepted subject to refund if it were later found to be excessive. Furthermore, such administrative proceedings to adjudicate tariff rates before the FERC are costly and time-consuming.

As an alternative to attempting to recover incremental costs through increasing an existing approved rate or filing new tariff rates, carriers could try to impose special charges to recover incremental capital or operating costs.

---

9271

Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel

Obtained and made public by the Natural Resources Defense Council, March / April 2002
by filing such charges as a part of the "rates and regulations" that normally cover the qualitative aspects of a tariff rate. Under this method, tariff regulations might support cost recovery in various forms, including a mandatory provision for the shipper to provide pipeline buffer material, a volume loss allowance, facility charges, or access charges. While the imposition of such special charges outside of the transportation tariff rate is possible, it is unlikely that material charges could be imposed without eliciting a shipper or FERC challenge, making this, too, an uncertain avenue for recovery of the unique costs.

Because of the difficulties presented by fitting ULSD into tariff rates, innovative approaches may be required. For instance, a pipeline carrier or an oil pipeline industry association might file an advance request with the FERC for a declaratory order either recognizing the validity of special charges or specifying the basis under which special charges would be applied to ULSD shipments. The purpose of seeking a declaratory order would be to clear a path for cost recovery before new capital or higher operating costs were actually incurred. Such an approach, with its earlier recognition of the issue, would allow the multi-year process to proceed well in advance of the collection of the new tariff rate.

The foregoing discussion suggests that higher capital and operating costs attributable to distributing ULSD will be difficult to recover, and that carriers will need to take proactive steps with the FERC and shippers in order to do so. There is no assurance that such steps will be successful, nor is there economic assurance that any such recovery will even be possible. Therefore, resistance among pipeline operators to incurring those costs should be expected.

Distribution Costs in the EIA Model

In its Regulation case analysis, EIA closely followed the EPA's assumptions about distribution costs, with the exception that EIA calculated the downgrade revenue loss within its NEMS model, using the prices of highway and non-road diesel generated from the model. From June 2006 through June 2010, EIA assumed an increased distribution cost markup of 1.2 cents per gallon on the price of highway diesel: 0.7 cents per gallon reflected the additional capital costs associated with handling two grades of highway diesel fuel during the phase-in period, 0.3 cents per gallon was the downgrade revenue loss, and 0.2 cents per gallon reflected other distribution costs, including operating and testing costs. The 1.2 cents per gallon additional distribution cost is slightly higher than the EPA's estimate of 1.1 cents per gallon. After June 1, 2010, the additional distribution cost associated with ULSD was 0.4 cents per gallon, including 0.2 cents per gallon for the downgrade revenue loss.94

EIA conducted a sensitivity analysis of higher distribution costs in the 10% Downgrade case. In the Regulation case, EIA followed the EPA assumption that ULSD product downgrade would be 4.4 percent of ULSD supplied. In the 10% Downgrade case, EIA assumed that 10% of ULSD would be downgraded from the highway diesel market. From June 2006 through June 2010, EIA assumed an additional distribution costs of 1.6 cents per gallon of highway diesel supplied. Of the 1.6 cents per gallon, 0.7 cents per gallon was for additional storage tanks to handle two on-highway diesel grades during the phase-in, 0.7 cents per gallon was for the revenue loss from downgrading ULSD, and 0.2 cents per gallon was for other distribution costs. After the end of the phase-in, in June 2010, the additional distribution cost was 0.9 cents per gallon: 0.7 cents per gallon for downgrade revenue loss and 0.2 cents per gallon for other distribution costs (see Chapter 6 for more detail).95

Summary

The Nation’s refined petroleum product pipeline system is not monolithic. Pipelines are distinguished by region, type of service, mode of operation, size, how much interface material they produce, and how they dispose of it. In preparing this report, a variety of pipeline companies were consulted, representing a cross-section of size, capacity, location, markets, corporate structures, and operating modes.

It is likely that the pipeline industry can distribute ULSD successfully, but major challenges arising from the unique specifications of a new product prevent a clear assertion that pipeline distribution of the material will be successful. In successfully distributing ULSD, oil pipelines will have to surmount numerous challenges:

• Coping with a product phase-in
• Demonstrating that untested pipeline batching techniques work
• Determining for the first time that sulfur content from other refined products does not “trailback” in pipelines and will not avoidably contaminate the new fuel


Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel

9271A

Obtained and made public by the Natural Resources Defense Council, March / April 2002
• Installing product quality testing equipment (which does not yet exist)

• Recovering operating costs that are not transparently recoverable under FERC regulations or market conditions

• Collecting, transporting, reprocessing, and selling up to twice the volume of existing pipeline transmix

• Reconfiguring an undetermined number of existing stations with new piping, tanks, manifolds, or valves

• Installing new loading facilities at distribution terminals.

Protecting the integrity of 15 ppm product will be more difficult than protecting the product integrity of the current 500 ppm product. The sulfur concentration of the neighboring product will more easily lead to contamination of the ULSD. Not only is the specification lower, with less room for error, but also the “potency” of the sulfur in the nearby product is higher.

It appears that the overall proposition of transporting ULSD is feasible. More problems can be expected to arise in handling ULSD among delivering pipeline carriers than among trunk carriers. In particular, those delivering carriers that cannot support fungible operations, are already short of working tankage, have complex routing and schedules, or have small markets at their end points will have the greatest difficulty in transporting ULSD.

The market impact of a contaminated batch will be stronger, however. With such a tight specification, there is little opportunity for blending lower sulfur material into an off-specification batch or tank. With the regulation applied as a cap with no averaging aspect, an off-specification tank in a terminal with only two tanks will quickly lead to a localized shortage of highway diesel, especially in areas where the market is thin and the infrastructure sparse.

Finally, there are uncertainties about transporting ULSD that cannot be resolved without hands-on experience with this unique product.
5. Short-Term Impacts on ULSD Supply

Background

This chapter addresses the transition to ultra-low sulfur diesel fuel (ULSD) when the ULSD Rule takes effect in 2006. Whether there will be adequate supply was one of the key questions raised by the House Committee on Science in its request for analysis. The Charles Rivers Associates/Baker and O’Brien (CRA/BOB) study done for the American Petroleum Institute (API) estimated a shortfall of 320,000 barrels per day when the regulation is introduced in 2006. The issue of future supply of highway diesel fuel “received considerable attention during the comment period” on the Notice of Proposed Rulemaking (NPRM) published by the U.S. Environmental Protection Agency (EPA). The EPA noted that “numerous commenters to the proposed rule indicated that they believed that the 13 ppm sulfur cap would cause shortages in highway diesel fuel supply” but that “a number of commenters also thought otherwise (i.e., that future supplies would be adequate).”

While it is possible that some refineries may decide to shut down altogether because of this regulation, others might just abandon the highway diesel market. Few refineries can operate without producing gasoline because gasoline is a high-margin, high-volume product that provides significant revenue to refineries. On the other hand, it may be possible for some refineries to operate without producing ULSD. Some refineries could sell higher sulfur distillate products into the non-road, rail, ship, or heating oil markets. Some refineries could also decide to export distillate products if they are in the right location.

Because there are other markets for distillate products, some refineries may opt to delay upgrading their facilities to produce ULSD. Refiners’ recent experiences with investing to meet new fuel standards have not been encouraging. As the EPA pointed out in the Regulatory Impact Analysis for this regulation, both the 500 ppm diesel fuel and reformulated gasoline standards resulted in overinvestment and oversupply of the fuels, and “of late, relatively poor refining margins have not allowed refineries to recoup the full cost of environmental standards.” Overly aggressive expansion to produce ULSD could result in similar oversupply of product and reduced margins, and some refineries may therefore wait to see whether adequate margins develop.

Another uncertainty is possible regulation of non-road diesel fuel. In addition, some States are proposing their own regulations for highway diesel fuel, which may add to the EPA requirements. Some refineries may wait to see whether additional requirements are established for highway or non-road diesel before investing to upgrade their refineries to produce ULSD.

The EPA has taken steps to monitor the ULSD supply situation. Its Final Rulemaking requires refiners and importers to submit a variety of information to ensure a smooth transition, and to evaluate compliance once the program begins. Refiners and importers expecting to produce highway diesel in 2006 are required to register with the EPA by December 31, 2001. Annual pre-compliance reports are required from 2003 through 2005, containing estimates of ULSD and 500 ppm sulfur fuel that will be produced at each refinery and projections of the numbers of credits that will be generated or needed by each refinery. A time line for compliance is also required, as well as other information.

The EPA will produce an annual report summarizing information from the precompliance reports without disclosing individual company plans. This information will give refiners a better indication of the potential market for credits and the availability of credits in each region. The EPA will also require annual reports after the program takes effect, in order to monitor production of ULSD and 500 ppm sulfur diesel fuel. In addition, an independent advisory panel will be set up to look at issues of diesel supplies and related technologies, and to report to the EPA annually on the progress being made by industry to comply with the ULSD Rule.

---


*Diesel Fuel News (March 5, 2001), p. 3

Energy Information Administration / Transition to Ultra-Low-Sulfur Diesel Fuel

9273

Obtained and made public by the Natural Resources Defense Council, March / April 2002