Appendix A

Letters from the Committee on Science,
U.S. House of Representatives
Mr. Lawrence A. Pettis  
Acting Administrator  
Energy Information Administration  
U.S. Department of Energy  
100 Independence Avenue, SW  
Washington, DC 20583  

Dear Mr. Pettis:  

The U.S. Environmental Protection Agency (EPA) has proposed a 15 parts per million (PPM) highway diesel sulfur cap effective at the refinery or import level beginning April 1, 2006. The same standard would be effective at the terminal level on May 1, 2006 and at the retail level on June 1, 2006. These deep sulfur reductions will require significant investments that not all refiners may choose to make. As a result, diesel fuel supplies could be affected. In addition, these extremely low-sulfur levels raise serious questions about the ability of the industry to adequately distribute the fuel in a fungible pipeline system that supports an array of different fuels and sulfur levels.

We believe that the EPA has not adequately studied the potential impacts of its proposed sulfur level on diesel fuel supply or the distribution system. EPA has also not fully assessed the availability of cost-effective desulfurization technologies that would be available in time to allow compliance with the new standard. As a result, an independent and objective study is needed that addresses, at a minimum, the following questions:

- Assuming that the rule as finalized as proposed (without a phase-in of the low sulfur fuel), what are the potential impacts on highway diesel fuel supply that could result? What impacts are possible on other mobile diesel products such as jet fuel, home heating oil and off-road diesel?
- If highway diesel fuel supply is adversely impacted, what are the potential impacts on the cost of diesel fuel to the end-users? To what extent would imports be able to fill any shortfall in supply and at what cost? How significant an effect would the 5% fuel efficiency loss associated with engines after-treatment devices have in the context of expected diesel demand under EPA's 15 PPM standard?
- EPA has proposed implementing the new diesel standard in April 2006. How would potential supply changes if the effective date was later (i.e., refinery changes for diesel did not have to overlap those for gasoline sulfur)?

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

14648

DOE017-1744

Obtained and made public by the Natural Resources Defense Council, March/April 2002
Mr. Lawrence A. Perri
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Perri:

The Energy Information Administration is about to begin a study requested by the Committee on Science on July 26, 2000 regarding the effect of the Environmental Protection Agency's (EPA) 15 parts per million diesel fuel standard. I am enclosing a copy of the July 26, 2000 letter for your information.

The EPA issued the final rule on December 21, 2000, which differs in several ways from the request the Committee made in July. As such, please modify the request to take the assumptions underlying EPA's final rule into account. Where EPA's assumptions diverge meaningfully from industry assumptions please perform a sensitivity analysis as appropriate. There are some significant differences between EPA and industry assumptions in several areas including:

- the Sulfur content of ultra-low-sulfur diesel (ULSD);
- efficiency loss from engine after-treatment devices; and
- additional distribution costs

Thank you for your attention to this matter. Please contact Tom Vanek of my staff at (202) 586-1776 if you have any questions.

Sincerely,

Harlan Watson
Staff Director
Energy & Environment Subcommittee

Enclosure

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

14649

DOE017-1745

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

Differences From the AEO2001 Reference Case
Appendix B

Differences From the AEO2001 Reference Case

The reference case for this study was established to provide a baseline scenario representing the nominal forecast for petroleum refining and marketing without the new requirement for ultra-low-sulfur diesel fuel (ULSD). The reference case reflects the mid-term reference case forecast published by the Energy Information Administration (EIA) in its Annual Energy Outlook 2001 (AEO2001). Both the reference case for this study and the AEO2001 reference case were prepared using EIA's National Energy Modeling System (NEMS). Both cases reflect the "Tier 2" Motor Vehicle Emission Standards and Gasoline Sulfur Control Requirements finalized by the U.S. Environmental Protection Agency (EPA) in February 2000. Both cases also incorporate bans or reductions for the gasoline additive methyl tertiary-butyl ether (MTBE) in the States where such legislation has been passed. They do not include a waiver of the Federal oxygen requirement for reformulated gasoline.

Updates in databases and assumptions that were incorporated into NEMS after the publication of AEO2001, however, resulted in minor differences in the reference case forecasts. Differences between the two forecasts relevant to the ULSD study are discussed in this appendix.

Return on Investment

The AEO2001 forecast assumed a 15-percent hurdle rate in the decision to invest and a 15-percent return on investment (ROI) over the 15-year life of a refinery processing unit. To be consistent with the EPA analysis, the reference case for this study used a 10-percent hurdle rate and a 5.2-percent ROI over a 15-year financial lifespan. The revised rates do not have a significant impact on the marginal costs for producing current 500 ppm highway diesel fuel in the reference case forecast.

Diesel Fuel Consumption

The AEO2001 reference case assumed that 85 percent of the demand for diesel fuel in the transportation sector was for highway use. More recently, however, EIA has determined that refinery production of highway diesel approximates the total demand for diesel fuel in the transportation sector. Therefore, the reference case for this study assumes that the production of 500 ppm highway diesel fuel is equal to the total demand in the transportation sector.

Two major factors account for the revised assumption. First, some of the highway diesel produced at refineries is downgraded in the distribution system. The EPA estimates that currently about 2.2 percent of highway diesel is downgraded. Second, some highway-grade diesel has been used for non-road or other uses, because the price differential between low-sulfur and high-sulfur diesel has not been large enough to make separate distribution infrastructures economical. As a result, it has been noted that some customers purchase low-sulfur diesel for non-road uses. In California, the State requires the same low sulfur standard for both highway and non-road diesel (except for railroad and maritime uses).

Import Supply Curves

The NEMS Petroleum Market Module (PMM) uses import supply curves developed from an international refinery model external to NEMS to represent the supply of available imports. In preparation for this study, new sets of crude and product import supply curves were estimated, adding supply curves for ULSD. The new import curves were used in the reference case for this study, but ULSD imports were not allowed.

Refining Technology Database

The PMM represents petroleum refining and marketing. The refining portion is a linear programming representation incorporating a detailed refining technology database that includes process options, product blending to specification, and investment costs. This database is updated annually to produce the AEO forecasts. There have been some minor changes since AEO2001, mostly associated with product blending. Although four new distillate desulfurization units were added as part of the refining technology database update, those four units were not allowed in the reference case. Therefore, the updates had minimal impact on the reference case for this study as compared with the AEO2001 reference case.

NEMS Operation Mode

For the AEO2001 reference case, all modules of the NEMS were executed to solve for supply and demand balance in the U.S. domestic energy market through 2020. For this study only the relevant modules were executed, including the International Energy Module, Transportation Demand Module, Industrial Demand Module, and the Petroleum Market Module. This mode of NEMS operation greatly reduced the model run time without significantly affecting the results.


161 Model documentation reports for NEMS and its modules as well as a summary report, NEMS: An Overview, are available at web site www.eia.doc.gov/assessment/docs.html.
Appendix C

Pipeline Regions and Operations
Appendix C
Pipeline Regions and Operations

U.S. Regions for Distribution of Petroleum and Their Key Pipelines

The supply and demand characteristics for refined petroleum products across the United States vary across regions (Petroleum Administration for Defense Districts, or PADDs). The reasons are historical, demographic, geological, and topographical.

The East Coast (PADD I), the most heavily populated PADD, has the highest petroleum consumption. It has virtually no indigenous crude oil production and only limited refining capacity. The Northeast is unique in its dependence on heating oil; 70 percent of all single-family homes in the Northeast are heated with oil. Hence, the Northeast has the largest market for the transportation of high-sulfur distillate, as opposed to low-sulfur diesel oil. The region covers its deficit in refined product supply with shipments from the Gulf Coast by pipeline and with imports of refined products by tanker. Colonial Pipeline (Gulf Coast to the New York area) and Plantation Pipe Line (Gulf Coast to the Washington, DC, area) are trunk lines that transport a wide product slate to the area, including distillate fuels. Delivering lines, such as Buckeye Pipe Line Company, distribute products within the New York Harbor and from the New York Harbor area to Pennsylvania and upstate New York. Buckeye also serves Connecticut and Massachusetts from an origin in New Haven. ExxonMobil and Sun also operate delivering product pipelines in the region.

The Midwest (PADD II) is less heavily populated than PADD I and has a greater balance of supply and demand for both crude oil and refined products. It receives pipeline supplies of distillate fuel oil from both the Gulf Coast and the East Coast. The main trunk carriers of refined petroleum products in the Midwest are TE Products Pipeline and Explorer Pipeline. The role of delivering carriers in the Midwest is a key to product distribution. The region’s refining hubs depend on pipelines to deliver their output. As logistics hubs, as well as refining hubs, areas such as Chicago ship product output from refineries and also re-ship product received from refineries on the Gulf Coast or in Oklahoma. Pipelines serving the Chicago hub include Williams, Equilon, and Phillips (in addition to Explorer and TE Products), Citgo, Marathon Ashland, Buckeye, and Wolverine. Other refining centers or single refineries also depend on pipeline transport of their products. Kaneb and Conoco are two of the pipelines serving the western part of PADD II, the plains States, where distances are long and consumption volumes low.

The Gulf Coast (PADD III) is the Nation’s main oil supply region. It is the largest refining area, with facility design and sophistication unrivaled in the world. It is a major crude oil producing area, with output greater than all but two members of the Organization of Petroleum Exporting Countries. It also has a low regional demand for finished petroleum products. Thus, its shipments of products to other regions are a central facet of supply east of the Rocky Mountains. The Gulf Coast is the origin of trunk carriers such as Explorer, TEPCO (to the Midwest), Colonial, and Plantation (to the Southeast and East Coast). These pipelines also deliver to points within PADD III.

The Rocky Mountain States (PADD IV) are thinly populated, with a low volume of oil shipped across long transport distances. Its consumption of diesel fuel for transportation on a per capita basis is about 60 percent greater than the average in the lower 48 States, but its consumption per square mile is less than 30 percent of the lower 48 average. The region’s highway consumption of diesel—a proxy for the low-sulfur diesel required—is about 60 percent of its total distillate market, but low-sulfur diesel accounts for more than 80 percent of the total distillate supplied in the region. The market is so thin that many companies have opted to market (and hence require transport and storage for) only low-sulfur diesel fuel instead of both low- and high-sulfur fuel. The pipelines serving the region distribute products from refineries in the Denver area and from refineries in Billings, MT; and Casper, WY, as well as product received from terminals in PADD II. Pipelines such as Yellowstone and Cenex distribute across the Northern Tier States. Chevron moves products out of Salt Lake City through Idaho and to western Washington, and a variety of pipelines go into and out of the Denver area (Phillips from PADD III; Chase from PADD II; and Conoco, WYCO, Sinclair, and others within the Rockies).

The West Coast (PADD V) is a singular oil market, separated from the rest of the country. From the earliest days, the Rockies prevented the easy transfer of oil in and out of the region. More recently, California’s adoption of uniquely stringent oil product specifications has exacerbated the region’s supply isolation. The region is populous as a whole because California is populous; consumption is high, but not on a per capita basis. In California, the Kinder Morgan pipeline system (formerly Santa Fe Pacific Pipeline) is the most important. It redistributes product from area refineries and, in southern California, receives product from its system in Arizona. The system in Arizona, in turn, connects with...
and destined for Points B and C can be delivered at both distant points simultaneously; part of the stream can continue on to Point C while delivery is still underway at Point B. In a batch mode, a delivery operation to Point B means that all pipeline movements beyond Point B cease while the delivery to Point B is completed.

Fungible operations also support more efficient utilization of storage tanks. In fungible operations, large storage tanks are used to accumulate or deliver multiple consignments of identical refined products. In batch operations, only one consignment of material is typically held in each tank. Accordingly, storage tanks used in batch pipeline operations tend to be smaller (and, possibly, more numerous) and are not utilized as intensively as storage tanks used in fungible service.

Among the pipeline characteristics that determine whether a refined petroleum products pipeline operates in a batch or fungible mode, customer requirements for segregation are an important factor. (Many pipelines operating on a fungible product basis can make provision to accept a distinct batch from a shipper. In doing so the carrier might impose a higher minimum volume requirement or charge a higher tariff rate to cover the higher operating cost of providing the special service.) Nonetheless, many pipelines or pipeline segments serve areas where the structure of the market does not support the "one size fits all" character of fungible service.

Another important factor in determining a pipeline's type of service offering is the possible availability of multiple pipelines in the same service corridor. If existing practice and customer service arrangements initially mandate batch pipeline service, it is difficult for a refined petroleum products pipeline carrier to change to fungible service subsequently. On the other hand, if a pipeline carrier serves a transportation corridor using multiple pipelines, it has more flexibility to adopt fungible service.

Thus, while an oil pipeline is likely to prefer fungible service, 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.

**Sequencing Product Flow**

Refined products pipelines carry more than 60 percent of all petroleum products transported in the United States. Products pipelines are routinely capable of transporting various types of products or grades of the same petroleum products in the same pipeline. For example, it is common for a single refined products pipeline to 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 products 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 products occupies nearly 50 miles of a 10-inch-diameter pipeline.

Generally, product 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. The actual volume of mixed material generated depends on a number of physical parameters, including pipeline diameter, distance, topography, and type of material. As a guide to understanding the volume of interface generated, it would be typical for 150 barrels of mixed material 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, while operations that require the flow to stop and start will generate the most interface material.

**Monthly Batch Scheduling**

As a part of their strategy to minimize the generation of interface material, pipeline operators sequence batches on the basis of the total number of products routinely shipped and the number and capacity of storage tanks available at the origin, destination, and intermediate breakout locations. Most often, pipeline operators use a recurring monthly schedule of "cycles," shipping all the available petroleum products of the same type in sequence. For example, only gasoline grades would be shipped during the days that constitute the gasoline cycle, and only distillates would be shipped during the days that constitute the distillate cycle. The actual duration of the cycles might vary from 6 to 10 days, depending on the volume of each material to be shipped during a particular month. Operators accommodate increased seasonal demand and stock builds, for instance, by adjusting the cycle schedule. The schedule is published

---


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

DOE017-1750

14654

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

Configurations of station piping necessary to accommodate a given number of tanks and to provide flexibility in routing multiple products in and out of those tanks provide many possibilities for the creation of pipeline interface material. Each pipeline facility is different, not only among pipeline companies but within pipeline companies. There is no way to predict how easy or hard it will be to minimize possible sulfur contamination of ULSD in station piping, except to examine the risks on a case-by-case basis.

In fact, 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 being a fixed value on a barrel-per-batch, not a percentage, basis. For instance, one pipeline operator may create 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.

Figure C1. Typical Product Sequence and Interfaces in a Refined Products Pipeline

![Diagram of product sequence and interfaces in a refined products pipeline.](energyinformationadministration.org)

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

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

DOE017-1751

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

Short-Term Analysis of Refinery Costs and Supply
Appendix D

Short-Term Analysis of Refinery Costs and Supply

As a result of the new regulations issued by the U.S. Environmental Protection Agency (EPA) for ultra-low-sulfur diesel fuel (ULSD) the U.S. refining industry faces two major challenges: to meet the more stringent specifications for diesel product, and to keep up with demand by producing more diesel product from feedstocks of lower quality. Some refineries in the United States and Europe currently have the capability to produce some diesel product containing less than 10 ppm sulfur, and there is no question that diesel fuel with less than 10 ppm sulfur can be produced with current technology.

U.S. refiners have demonstrated that meeting the EPA target specification of 500 ppm sulfur (1993 reduction from 5,000 ppm to 500 ppm) was easier than anticipated. The primary methods used were upgrading existing hydrotreater units by adding extra reactor volume and building new units. In contrast, the proposed change from 500 to 15 ppm represents a new and far more challenging task for the industry, because the remaining sulfur (less than 500 ppm) is likely to be contained in compounds that are difficult to desulfurize, such as 4,6-dimethyldibenzothiophene (often described as stenically hindered sulfur-containing molecules). Furthermore, to meet growing demand for diesel fuel, some refineries will have to increase capacity, which may involve treating lower quality feedstocks (cracked distillates) that require more severe and costly process conditions.

The implications of producing ULSD are complex, not only from a unit-specific standpoint but also from a refinery standpoint. Each refinery has unique circumstances, such as existing hydrosulfurization units, source of crude, diesel blend components, and hydrogen availability. Producing ULSD is a significant decision for most refiners, and the incremental cost per barrel could vary dramatically across the range of individual refineries. In addition, it is uncertain whether further restrictions on diesel quality will be imposed in the future. Some refiners may decide to continue producing highway diesel and produce only non-road diesel and heating oil as distillate products. Such decisions, coupled with increasing demand for diesel fuel, could heighten the potential for a diesel shortage in 2006.

This appendix provides details of the methods used to estimate the short-term cost per gallon to manufacture ULSD meeting the EPA sulfur specifications for 2006 and examines the variations in cost for different U.S. refineries. The analysis results in a cost curve indicative of the cost that may be incurred by U.S. refiners to produce the new fuel at various supply levels.

Estimating Components of the Distillate Blend Pool

The initial step of the analysis was to analyze the potential economics of producing ULSD for each refinery. Using input and output data submitted to the Energy Information Administration (EIA) by refiners, the current components of the distillate blend pool were estimated and allocated to the current production of highway diesel, non-road diesel, and heating oil. Volumes and sulfur content of straight-run distillate, fluid catalytic cracker (FCC) light cycle oil (LCO), coker distillate, and hydrocracker distillate were estimated on the basis of the gravity and sulfur content of crude feeds, input volumes to the FCC, coker, and hydrocracker units, and the fraction of the FCC feed that is hydrotreated.

The estimates for volumes of full-range straight-run distillate, LCO from the FCC, and coker distillate were adjusted according to reported refinery data. Because kerosene and jet fuel are made from the straight-run distillate and hydrocracked material, those distillate pool components were reduced accordingly. If a hydrocracker was available at a refinery, volumes of LCO and coker distillate were allocated to the hydrocracker by comparing available distillate boiling range components to distillate product volumes. A final adjustment was made, based on the relative production of gasoline and distillate products.

The initial estimate of straight-run distillate volume for a given refinery was based on a typical cut point range for a crude oil with the gravity of the crude oil charged to that refinery. If the available distillate pool volumes exceeded the distillate product produced, the volume of the straight-run distillate component was reduced, based on the typical variation in distillation cut points. (The light end of the kerosene boiling range material may be included in the reformer feed for gasoline production, and the heavy end (high end) of the boiling range may be included in the FCC feedstock. Either or both of these adjustments will reduce the straight-run distillate volume.) The adjustments resulted in estimated distillate pool volumes approximately equal to the reported volumes of distillate production. The distillate pool components were then allocated to the production of highway diesel, non-road diesel, and heating oil.
components to reduce aromatics and improve cetane in order to produce acceptable products.

In the longer term, increased movement of cracked distillates between refineries could occur, with more under-cutting of cracked stock to remove the high-aromatic, high-sulfur material at the high end of the boiling range. Such industry optimization avenues would take time to establish, however, because they are based on component price differentials that may grow over time to provide incentives for such activities. During the transition period starting in 2006, based on past experience, it is assumed that most refiners would base their strategies on analyses of specific refinery situations. Possible exceptions are multiple refineries within a single company system having logistical connections that permit practical and economical movement of refinery streams.

Identifying Refinery Options for Producing ULSD

The objective of this step of the analysis was to generate estimates of the incremental cost for each refinery to produce ULSD. The incremental cost will vary for each refinery, depending on the volume of ULSD produced; the type of blend components from which it is produced; the sulfur, aromatics, and boiling range content of those blend components; whether the refinery can revamp an existing hydrotreater or must build a new one; and the cost for catalyst, hydrogen, and other requirements to produce the ULSD. Moreover, each refinery must decide how much ULSD it will produce in 2006. Because the volume of ULSD produced will affect the incremental cost of production, the incremental cost of ULSD production for each refinery was first estimated at current production levels, assuming both the revamp of a current hydrotreating unit and the addition of a new unit. Then, additional options for reducing or expanding the refinery’s ULSD production were estimated.

Several factors may cause a refiner to maintain, contract, or expand highway diesel production when the ULSD regulation takes effect in 2006. Maintaining current production of highway diesel has the appeal of keeping the refinery production in balance with current distillate markets sales for the company. Either increasing or decreasing the highway diesel production will mean finding markets for more highway diesel, more heating oil, or more non-road diesel products. Reducing ULSD production may result in a lower per barrel incremental cost for ULSD production.

ULSD production requires added hydrogen usage in the distillate hydrotreater, thereby increasing hydrogen consumption per unit of distillate feed. Some refineries may choose to reduce feed input in order to continue to operate within existing hydrogen supply constraints and avoid building new hydrogen production capacity. Reducing hydrotreater throughput may also enhance the practicality of revamping a current hydrotreater to avoid building a new unit. The 1996 API/NPRA survey showed that at the 500 ppm sulfur limit level, about 15 percent of untreated material was placed in highway diesel in PADDs I-IV. Producing ULSD will require that all the diesel product be hydrotreated. This means that some refineries who seek to revamp will be working with a unit that has less capacity than indicated by current highway production. Some additional capacity may be made available by increasing the utilization rates of existing units that are currently operating at lower utilization rates.

If a refiner has to build a new hydrotreater, expansion of highway diesel production is an obvious consideration.

Table D2. Cetane Number of Light Cycle Oil From Some World Crude Oils

<table>
<thead>
<tr>
<th>Crude Oil</th>
<th>Source</th>
<th>Gravity (Degrees API)</th>
<th>Sulfur Content (Percent by Weight)</th>
<th>Straight-Run Diesel</th>
<th>Light Cycle Oil at 60 Percent Conversion</th>
<th>Light Cycle Oil at 80 Percent Conversion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Murban</td>
<td>Abu Dhabi</td>
<td>39</td>
<td>0.3</td>
<td>56</td>
<td>40</td>
<td>22</td>
</tr>
<tr>
<td>Saudi Arabia Light</td>
<td>Saudi Arabia</td>
<td>34</td>
<td>1.7</td>
<td>58</td>
<td>32</td>
<td>18</td>
</tr>
<tr>
<td>Forcados</td>
<td>Nigeria</td>
<td>31</td>
<td>0.2</td>
<td>39</td>
<td>25</td>
<td>&lt;15</td>
</tr>
<tr>
<td>Fones</td>
<td>North Sea</td>
<td>37</td>
<td>0.3</td>
<td>52</td>
<td>37</td>
<td>20</td>
</tr>
<tr>
<td>Maya</td>
<td>Mexico</td>
<td>22</td>
<td>3.3</td>
<td>47</td>
<td>25</td>
<td>15</td>
</tr>
<tr>
<td>Bescan</td>
<td>Venezuela</td>
<td>10</td>
<td>5.5</td>
<td>39</td>
<td>21</td>
<td>&lt;15</td>
</tr>
<tr>
<td>North Slope</td>
<td>Alaska</td>
<td>27</td>
<td>1.0</td>
<td>45</td>
<td>30</td>
<td>17</td>
</tr>
<tr>
<td>Gibson Max.</td>
<td>Louisiana</td>
<td>36</td>
<td>0.3</td>
<td>55</td>
<td>40</td>
<td>22</td>
</tr>
<tr>
<td>West Texas Sulf</td>
<td>Texas</td>
<td>32</td>
<td>2.4</td>
<td>47</td>
<td>32</td>
<td>18</td>
</tr>
</tbody>
</table>

Note: It was assumed that 550-10SF vacuum gas oil was cracked at 60 percent or 80 percent volume conversion. Properties of the vacuum gas oil and cetane number of straight-run diesel are from the Ethyl Corporation crude oil database. Source: G.H. Unkelman, "Diesel Fuel Demand: A Challenge to Quality." Presentation to the Energy Economics Group, Institute of Petroleum (London, UK, October 10, 1983).
produce ULSD. The volume of ULSD a refiner decides to produce will affect the cost. For each refinery, the cost for ULSD production is estimated at current production levels, both assuming the addition of a new hydrotreating unit and assuming the revamping of an existing hydrotreating unit (options 1 and 2 below). Three additional options are considered (reductions from current highway diesel production assuming new and revamped hydrotreater units and increases from current production assuming new units) to find the most economical production levels for individual refineries.

Option 1 (Baseline New Hydrotreater): This "business-as-usual" option is modeled using the current refinery production capacities for highway and non-road diesel. The model estimates the cost to produce highway and non-road diesel at the proposed sulfur limits (7 ppm and 5,000 ppm, respectively) while maintaining the same hydrotreater throughput. A new hydrotreater plant is estimated.

Option 2 (Baseline Revamped Hydrotreater): This option is identical to Option 1 except that the existing hydrotreater plant is assumed to be revamped. The revamp option considers the cost of installing an additional hydrotreater reactor (not an entire plant) and interstage amine scrubber. The additional reactor is sized to decrease the existing diesel sulfur content from 300 ppm to 7 ppm.

Options 3 and 4 (Reduced ULSD New and Revamp Hydrotreater): These options consider the cost impacts of decreasing highway diesel production and increasing non-road diesel production. Because ULSD production will require more hydrogen consumption (especially for refineries with lower quality feedstocks), reducing ULSD production may permit the refinery to operate within existing hydrogen capacity and avoid the necessity of building a costly new hydrogen plant. Furthermore, reducing hydrotreater throughput may also enhance the practicality of revamping the current hydrotreater and avoiding the need to invest in a new unit.

Option 5: Increased ULSD New Hydrotreater: This option considers expanding highway diesel production while decreasing non-road diesel production, thus increasing throughput to the hydrotreater and creating the need for a new hydrotreater. A particular refiner might consider this option for several reasons: (1) the refinery has a high volume of cracked stocks, and a new hydrotreater plant is needed anyway; (2) a new unit may provide economies of scale and lower per-unit production cost; (3) there may be a perceived opportunity to expand highway diesel production as demand increases and "challenged" refineries discontinue diesel production. A corresponding revamp case was not considered, because it was assumed that current refineries were at maximum production rate with existing equipment, and both new hydrotreater and hydrogen plants would be needed.

Worksheet Environment

Economic Factors: The capital charge factor is assumed to be 12.0 percent (corresponding to a 5.2-percent after-tax rate of return on investment), contingency 20.0 percent, on-site maintenance 4.0 percent, off-site maintenance 2.0 percent, taxes and insurance 1.5 percent (included in the capital charge factor), and miscellaneous 0.6 percent, all as a percentage of capital investment. Sensitivity cases using a 17.2-percent capital charge were also analyzed.

Refinery Input Data: The cost model requires two input data sets for each scenario. The first set is input data is the baseline data, consisting of the current refinery diesel capacities from which all scenarios are developed. The baseline data consist of the API gravity, highway and non-road diesel blend component flow rates, and sulfur content of each stream to the hydrotreater. The second set of input data contains the blend component flow rates for the optional expanded or reduced hydrotreater.

Manual Variables: Some variables are not available in the original refinery-by-refinery specific database and require some engineering judgment and estimation. Whether or not the FCC feed is hydrotreated affects the hydrogen consumption for desulfurizing the LCO stream. Pretreatment of the FCC feed results in products (LCO in this case) with higher API gravities (lower sulfur and aromatic content), which will in turn require less hydrogen to remove the remaining sulfur during hydrotreating. The geographic location factor is utilized in the cost estimates for each refinery process; the location basis used in the model is the U.S. Midwest. The pressure input (in pounds per square inch absolute [psi]) affects both the kinetic and hydrotreater portions of the model. It is assumed that the maximum pressure for the revamp options is 650 psi, and the average length-of-run pressure for the new hydrotreater options is 900 psi. The estimated process temperature has a direct impact on the kinetic performance.

Hydrotreater Kinetics: The kinetic model used in this study has the general form:

\[-dS/dt = kS\hat{P}H_2/(1 + KS_d)\]

An Arrhenius form is used for the temperature dependence of k. For the Langmuir-Henkelwood factor, it is assumed that sulfur species in the feed and H2S are equally strongly absorbed on catalyst sites. The constants in the equation were fit using the best available data from the literature. The best fit was obtained with n equal to 1.5. The equation was integrated to give space
Hydrotreater Utilities: The main utilities for the hydrotreater plant included in the model are power, steam, cooling water, and fuel. All utility requirements were estimated from published correlations or actual data. The revamp option utility requirements are the incremental utilities to remove the remaining sulfur present in the diesel. The incremental additional power was estimated to be 40 percent of the existing power usage due to additional hydrogen consumption and potentially higher system pressure drops.

Hydrotreater Yields and Energy Content: The volume and weight percent yields of ULSD produced by the distillate hydrotreater can vary considerably, depending on the fraction of cracked stocks in the feed and the level of aromatics saturation. An average yield and energy content were estimated for this study, based on the Criterion data in a June 2000 study by the National Petroleum Council. The yield of hydrotreater product in the distillate boiling range was assumed to be 98 percent by weight, and the API gravity was assumed to increase by 2 numbers, which means that the volume yield was 99.2 percent. There was also a small increase in the Btu content of the product on a weight basis (98.2 percent of the feed energy content in 98.0 weight percent of the feed). The energy content declines on a volume basis, because the heat content of the product is 0.989 times the heat content of the feed on a volume basis.

Hydrogen Plant: The same hydrogen consumption and hydrogen plant cost estimation methodologies are used for both the new and revamp cases. The goal of the hydrogen plant portion of the model is to determine the hydrogen consumption and associated costs to reduce the current sulfur level (500 ppm) down to 7 ppm, whether it is a new or revamp situation (see Table 6 in Chapter 6). The incremental H₂ is calculated as the difference between the baseline H₂ consumption (for highway diesel at 500 ppm sulfur and non-road diesel at 5,000 ppm) and the predicted required H₂ consumption (highway diesel at 7 ppm, non-road at 5,000 ppm). If the incremental H₂ consumption value is greater than 25 percent of the baseline H₂ capacity, then the model calculates the H₂ costs based on a new plant.

Simple nonlinear correlations based on the flow rate and sulfur concentration of each cut, including the non-road streams to the hydrotreater, were developed using data compiled from multiple sources. The H₂ consumption correlations are as follows:

Straight-run highway baseline:

\[ SCF_{H₂} = SR \text{ Flowrate} \times \left( \frac{120 \times SR_{SulPercent}}{\text{CO}_2} + 40 \right) \]

Straight-run highway required:

\[ SCF_{H₂} = SR \text{ Flowrate} \times \left( \frac{120 \times SR_{SulPercent}}{\text{CO}_2} + 40 \right) + 50 \]

Straight-run non-road baseline and required:

\[ SCF_{H₂} = SR \text{ NonHighway Flowrate} \times \left( \frac{120 \times SR_{SulPercent}}{\text{CO}_2} + 40 \right) \]

LCO highway baseline:

\[ SCF_{H₂} = LCO \text{ Flowrate} \times \left( \frac{115 \times LCO_{SulPercent}}{\text{CO}_2} + 40 \right) + 150 \]

LCO and coker distillate highway required:

\[ SCF_{H₂} = LCO \text{ Flowrate} \times \left( \frac{115 \times LCO_{SulPercent}}{\text{CO}_2} + 40 \right) + 150 + 650 \]

LCO and coker distillate non-road baseline and required:

\[ SCF_{H₂} = LCO \text{ NonHighway Flowrate} \times \left( \frac{115 \times LCO_{SulPercent}}{\text{CO}_2} + 40 \right) \]

After the total baseline, required, and incremental hydrogen capacities are calculated, the model then decides whether to build a new hydrogen plant. If the existing H₂ plants capacity is determined to be sufficient (no build), only the variable cost associated with the required capacity is calculated. If a new H₂ plant is necessary, the on-site capital cost is estimated (scaled) using published data (60 million standard cubic feet per day plant at $50 million). The off-site capital cost is assumed to be 40 percent of the on-site capital cost. The total hydrogen cost per barrel of distillate treated includes the cost of the natural gas feed to the hydrogen plant.

Sulfur Plant: The new sulfur plant estimates are based on the amount of sulfur removed from the diesel pool and are a function of whether the FCC feed was pre-treated, the flow rate and percent sulfur of each stream, and the API gravity of the crude. The estimate

---

14660

DOE017-1756

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

Model Results
Appendix E

Model Results

This appendix provides mid-term projections for end-use prices and total supplies of ultra-low-sulfur diesel fuel (ULSD), based on the Energy Information Administration’s (EIA’s) National Energy Modeling System (NEMS) Petroleum Market Module (PMM). Historical data for 1999 prices and supplies of highway diesel (500 ppm sulfur) are also provided for comparison (Tables E1 and E2).

The projected end-use (pump) prices are lower than the current prevailing prices for highway diesel fuel for several reasons. The end-user prices include crude oil costs, processing costs, taxes, and marketing costs. Therefore, variations in the costs and taxes affect the projected end-user prices. The reference case, the Regulation case, and all sensitivity cases were based on mid-term projections for world crude oil prices used in Annual Energy Outlook 2001 (AEO2001). After the steep increase in world crude oil prices in 1999 and 2000, EIA projected that crude oil prices would decline initially (through 2003), then slowly increase through 2020. The EIA’s Weekly Petroleum Status Report for March 23, 2001, estimated the February 2001 price at $24.60 per barrel ($0.577 per gallon) in 1999 dollars for U.S. imported crude oil. In comparison, NEMS projects a world crude oil price of $21.37 per barrel ($0.509 per gallon) in 2010 (in 1999 dollars). The lower 2010 oil price projections from AEO2001 thus account for a difference of 6.8 cents per gallon in the projected end-use prices for ULSD.

In addition, the end-use diesel prices include a nominal Federal tax of $0.24 per gallon in 1999, which decreases in value (in real terms) in the forecast years. The differential in Federal taxes between 1999 and 2010 is about 4 cents per gallon. The PMM reference case projects an end-use price of $1.238 per gallon in 2010. After upward adjustment to account for the differentials in world crude oil price and Federal taxes (a total of 10.8 cents), the end-use price would be $1.346 per gallon at the current world crude oil price level.

The U.S. prices of most petroleum fuel products fluctuate between seasons and in response to world crude oil prices. The higher-than-normal diesel prices in 2000 and in the early part of 2001 reflect the low distillate inventory and high world crude oil prices. Since February 2001, the average price of U.S. highway diesel has been dropping steadily, to a level around $1.40 per gallon. According to the Weekly Petroleum Status Report for March 23, 2001, the average U.S. price of highway diesel was $1.338 per gallon (in 1999 dollars), comparable to the price projection of $1.346 per gallon from the PMM.


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

14662

DOE017-1758

Obtained and made public by the Natural Resources Defense Council, March/April 2002
## Table E2. End-Use Prices and Total Supplies of Highway Diesel, 1999 and 2007-2015, Assuming 10-Percent Return on Investment

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>End-Use Prices of Highway Diesel (1999 Cents per Gallon)*</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reference with 10% Return on Investment (500 ppm)</td>
<td>114.0</td>
<td>121.9</td>
<td>122.5</td>
<td>123.3</td>
<td>123.8</td>
<td>124.4</td>
<td>125.4</td>
<td>122.6</td>
<td>124.8</td>
</tr>
<tr>
<td>Regulation with 10% Return on Investment (ULSD)</td>
<td>NA</td>
<td>129.8</td>
<td>130.0</td>
<td>130.9</td>
<td>131.5</td>
<td>132.4</td>
<td>131.1</td>
<td>130.6</td>
<td>130.5</td>
</tr>
<tr>
<td>Total Highway Diesel Supplied (Million Barrels per Day)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Reference with 10% Return on Investment</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total (500 ppm)</td>
<td>2.43</td>
<td>3.10</td>
<td>3.16</td>
<td>3.22</td>
<td>3.27</td>
<td>3.33</td>
<td>3.56</td>
<td>3.19</td>
<td>3.44</td>
</tr>
<tr>
<td>Regulation with 10% Return on Investment</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>500 ppm</td>
<td>2.43</td>
<td>0.70</td>
<td>0.71</td>
<td>0.73</td>
<td>0.26</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
<td>0.00</td>
</tr>
<tr>
<td>ULSD</td>
<td>0.00</td>
<td>2.41</td>
<td>2.46</td>
<td>2.50</td>
<td>3.02</td>
<td>3.41</td>
<td>3.04</td>
<td>2.60</td>
<td>3.52</td>
</tr>
<tr>
<td>Total</td>
<td>2.43</td>
<td>3.11</td>
<td>3.17</td>
<td>3.23</td>
<td>3.29</td>
<td>3.41</td>
<td>3.54</td>
<td>3.20</td>
<td>3.52</td>
</tr>
</tbody>
</table>

*Highway diesel prices (both 500 ppm and ULSD) include Federal and State taxes but exclude county and local taxes.
NA = not available.

Thanks,
Michelle