b5

Department of Energy
Washington, DC 20585

SEP 1 4 2001

MEMORANDUM FOR THE SECRETARY

THROUGH: KYLE MCSLARROW
CHIEF OF STAFF

FROM: VICKY A. BAILEY
ASSISTANT SECRETARY
OFFICE OF POLICY AND INTERNATIONAL AFFAIRS

Vicky A. Bailey

SUBJECT: ACTION: Attendance by Senior DOE Officials at Proposed Indo-U.S. Conference on Natural Gas in New Delhi, India on November 7-8, 2001

ISSUE: What senior DOE officials will attend the proposed conference.

29988

b-5

CONCUR _______________ NON-CONCUR __________________ DATE _________

Attachment:

Revised Agenda

Department of Energy
Washington, DC 20585

2001-016239

September 14, 2001

Paul and Nancy Vigyikan

b6

Dear Mr. and Mrs. Vigyikan:

Thank you for your letter to President Bush regarding the National Energy Plan (NEP) and your interest in energy conservation. The NEP, released on May 16, 2001, contained 105 recommendations to improve our energy future. Of those, 54 dealt with energy efficiency and renewable energy. This Administration strongly supports energy efficiency as one of the building blocks to a strong energy policy while recognizing the need to increase supply. Adding additional fuel supplies will reduce our dependence on foreign sources and increase our energy independence. An entire chapter of the Plan discusses the importance of savings gained by energy efficiency and outlines a broad scope of activities to improve efficiency throughout the federal government and beyond.

We are moving ahead in our efforts to implement many of the NEP recommendations. The Office of Energy Efficiency and Renewable Energy (EERE) is in the process of performing a strategic program review that will carefully evaluate ongoing programs to ensure that they provide maximum benefits to U.S. taxpayers. Once the review is completed, we will correct program inadequacies or refocus our efforts to higher performing activities.

Additionally, EERE held a series of public meetings across the country in June to receive public comments on the objectives of the current energy efficiency and renewable energy research, development, demonstration and deployment programs and whether these Federal programs are achieving intended objectives. In response to the public comment period, we received input from approximately 5,000 people and organizations. Completion of the above efforts will ensure that our federally-funded energy efficiency and renewable energy programs will continue to be an integral part of our nation's energy future.

I believe that the Plan presents a balanced blueprint for our nation's energy future. Again, thank you for your interest in energy conservation.

Sincerely,

David K. Garman
Assistant Secretary
Energy Efficiency and Renewable Energy

29990

2001-018572

Department of Energy
Washington, DC 20585

September 18, 2001

Mr. Charles L. Campbell
(b)(6)

Dear Mr. Campbell:

Your fax to President Bush regarding U.S. energy and environmental issues has been forwarded to the Department of Energy, Office of Nuclear Energy, Science and Technology, for response.

Thank you for your support of the *National Energy Policy* and for sharing your ideas and concerns. The Department is pursuing full implementation of the *National Energy Policy* and is also working on a comprehensive and practical response to climate change concerns. We agree with your assessment that nuclear energy, renewables, and other resources must be applied to address our energy and environmental challenges.

As you anticipate, we expect a vigorous debate on energy policy in the weeks and months ahead. We welcome your ideas and comments as we engage this important issue and set a course that assures the long-term energy security of the United States.

Once again, thank you for your letter and for sharing your concerns.

Sincerely,

Will Magwood

William D. Magwood, IV, Director
Office of Nuclear Energy, Science
and Technology

cc: Ms. Trudy Roddick
Director, Mail Analysis
The White House

Susan S. Kwak B6

September 20, 2001

Dear President Bush,

Your energy policy is insufficient action to address the issue of global warming.

The focus of your plan as announced in March of this year, is to increase domestic fossil fuel supply. With this focus of supply, you have walked away from your campaign pledge to regulate carbon dioxide emissions from U.S. power plants and refused to ratify the Kyoto Protocol. Instead, the actions planned include a $2 billion subsidy program for the coal industry, continual building of new power plants with a renewed commitment to nuclear power, rollbacks of key clean air rules, opposing caps on carbon dioxide emissions, and drilling for oil in the Arctic National Wildlife Refuge, as well as other sensitive areas.

The justification for pursuing this strategy has been that implementing the Kyoto Protocol and regulating carbon dioxide emissions from power plants will harm the U.S. economy. The pitch has been that we are in need of energy right now, and that big oil, electric, and coal companies need our help to provide it. You have stated that carbon dioxide is not considered a pollutant under the Clean Air Act, and yourself and members of your administration have indicated repeatedly that other industrialized countries share the U.S. position in not supporting the Kyoto protocol.

The claim that CO^2 would be too costly to regulate is based upon a Department of Energy report, (the McIntosh-EIA report), provided by the Energy Information Administration. I was surprised to find that such a significant claim would be based upon a single report, one that has been criticized for failing to consider how energy efficiency may be significant in reducing greenhouse pollution, and whose conclusions have not been substantiated by analysis on the part of your administration. If reports are to be believed in such a manner, the National Resource Defense Council notes two other comprehensive government studies which have shown that it is possible to reduce greenhouse pollution to levels called for in the Kyoto agreement without harming the economy.

The claim that carbon dioxide is not considered a pollutant under the Clean Air Act is simply not true. Carbon dioxide undeniably fits the definition of an air pollutant under the Clean Air Act. By any standard, it is an air pollutant, but it can be seen in section 103(g) of the act, when Congress included emissions of carbon dioxide from fossil fuel power plants on a list of air pollutants to be included in pollution prevention programs directed by the EPA. Carbon dioxide has not been regulated by the EPA yet, but this does not mean it is a nonpollutant.

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And the results of this summer's international meetings in Genoa are clear evidence that industrialized countries do support the protocol. Why are there 80 countries who have signed the Protocol? Why did other countries continue to settle country-by-country limits on emissions of greenhouse gases, even without U S participation? Because everyone has accepted the basic science of global warming, that the global temperature is rising due to the collection of greenhouse gases; chief among these gases is carbon dioxide. While it is true that the consequences of rising temperatures are uncertain, there is no debate that this is an international problem

Sir: if you take the issue of global warming seriously, you must change your energy policy and take leadership in solving the problem of climate change. Specifically, I urge you to:

- REDUCE GLOBAL WARMING POLLUTION. Electric power plants are the country's largest source of global warming pollutants. There must be controls on all four pollutants that are generated by power plants, including carbon dioxide, the main cause of global warming.

- INCREASE ENERGY EFFICIENCY. Offer tax incentives and set higher standards for energy efficiency in our homes, offices, and factories. The current energy policy does not include rewards for energy efficiency, even opposes appliance efficiency standards. Yet a November 2000 Department of Energy report found that energy efficiency and renewable power sources could meet 60 percent of the nation's needs for new power plants.

- INCREASE FUEL EFFICIENCY. Raise the fuel efficiency standard for new passenger vehicles to 40 mpg. Cars, trucks, and buses are responsible for 20% of the U.S. greenhouse gas emissions and your administration has given no commitment to raise fuel economy standards. The new standard would cut carbon dioxide pollution by 600 million metric tons and save consumers at least $45 billion a year at the gas pump. The amount of oil we would save is more than we would get from all our Persian Gulf imports, the Arctic wildlife refuge, and California offshore oil drilling combined (Sierra Club).

- INCREASE RELIANCE ON RENEWABLE ENERGY SOURCES. Increase the amount of electricity produced from renewable sources to 20 percent by 2020. We must decrease U.S. reliance on coal and oil. There are no other options.

- DEMONSTRATE INTERNATIONAL LEADERSHIP. Please do not abandon the Kyoto protocol. The U.S. should not only participate, but lead, for the world to successfully stop global warming.

As a consumer of energy, as on who believes public and environmental health should be protected and strived for, and as a proud American, I urge you to make the world different and change your energy policy. Thank you.

Sincerely yours,
Susan S. Kuch

29993

b6

2001-021847 9/25 A 10:55

Secretary, The

From: B6
Sent: Sunday, September 23, 2001 2:35 PM
To: Secretary, The
Subject: Fossil Energy

021847 2001 SEP 25 A 10:55

FROM: B6
NAME: Harriet Cheney
SUBJECT: Fossil Energy
ZIP: B6
CITY:
PARM.1: TO:the.secretary@hq.doe.gov
STATE:
TOPIC: National mobilization
SUBMIT: Send Comments
CONTACT: email
COUNTRY: USA
MESSAGE: Secretary Abraham: What I'd like to see is government officials rise from being political operatives to real leaders. What I'd like to see is a national energy policy whereby we rid ourselves of our onerous addiction to fossil fuel. This would free our country to make foreign policy decisions based on ethics and good sense. Why can't we float "energy bonds" to fuel a national effort to convert to renewable sources of energy? This would not only buoy up the economy -- but would also help protect our endangered environment (which probably poses a greater threat to our future than terrorists). Why haven't we done this before? remember the gas lines of 1973. We need our leaders to help us be the best we can be. As 4% of the world population, we should not be using 44% of the world's resources. God Bless America,
Harriet Cheney
MAILADDR: B6

29994

2001-020617

Department of Energy
Washington, DC 20585

October 25, 2001

Mr. W.E. Gene Claudin

b(6)

Dear Mr. Claudin:

I am responding to your letter to President Bush which commented on several aspects of the Administration's National Energy Policy released in May. You can obtain more information by visiting the White House website at: www.whitehouse.gov/energy.

Let me assure you the National Energy Policy is being implemented in a manner that will assure accountability. By Federal law, performance objectives are established for all major programs implemented by the Department of Energy and other Federal agencies, and progress toward achievement of these objectives is regularly tracked and reported.

Your recommendations concerning expanded use of nuclear energy and release of information on development of the National Energy Policy have been conveyed to key decision makers within the Department.

Thank you for writing.

Regards,

David Pumphrey for

Vicky A. Bailey
Assistant Secretary
Office of Policy and International Affairs

29995

2001-018617

Hebron, Estelle

From: Mollot, Darren J
Sent: Monday, November 26, 2001 1:53 PM
To: (b)(6)
Subject: Correspondence - National Energy Policy

Mr. Murray Duffin
This is in response to your email to Secretary Abraham dated August 7, 2001 regarding the National Energy Policy. Your obvious interest and desire to get involved in the formulation of energy policies that will effect our Nation's future is admirable and critically important. It is the efforts of people like your self, who educate themselves and take the time to participate in national as well as grass roots efforts, that ultimately shape energy policy.

Though many of the points you make are legislative and need to be addressed to your Congressman and Senators, I never the less thought you might be interested in what your Department of Energy is doing in the areas you seem to be interested in. There is a general consensus that we will have to reduce our reliance on fossil fuels over the long term. What "long term" means is a widely debated question and will depend largely on how fast cost effective and reliable alternative technologies can be developed. As you might imagine, the Department of Energy, in cooperation with private industry, has committed significant resources toward developing cost effective and reliable renewable technology. There has been a lot of progress. Over the past few decades many of these power systems have developed to the point that they are commercially viable in niche applications. But, as you are aware, a lot of work is still needed. I urge you to visit the energy efficiency index page of the DOE web site at <http://www.energy.gov/efficiency/index.html> for more information. Similarly, there is a lot of work being done to improve the efficiency of fossil power generation technology. In addition to improving efficiency and reducing regulated pollutants, continued advances in technologies that will allow CO_2 to be permanently sequestered from the atmosphere should allow us to build a coal or natural gas electric power plant in 2020 that will produce near zero harmful emissions (including CO_2). For more information on fossil energy programs you may want to visit the Fossil Energy web site at http://www.fe.doe.gov> .

In addition, there are numerous projects and planning efforts underway which address hydrogen production and transmission, building, appliance, and transportation efficiency, safe nuclear fission and fusion technologies, super conductors to improve the performance of the electric transmission, technologies to improve yields from existing and previously inaccessible oil and natural gas reservoirs and on and on. Information on most of these can be found on the previously cited web pages as well. Another excellent source of information on how much, and what types of energy we use here in the U.S. and internationally, is the Energy Information Administration. The EIA is a quasi-independent organization within DOE that is tasked with providing unbiased energy data and forecasts. Their web address is http://www.eia.doe.gov <http://www.>.

Hope that this information is of value. Once again, thank you for your interest in energy issues.

Darren Mollot

Darren J. Mollot, PhD
Technical Advisor
Office of Fossil Energy, FE26
U.S. Department of Energy
1000 Independence Ave. SW
Washington, DC 20585

tel: 202 586-0429
fax: 202 586-1188

29996

Carter, Douglas

From: Porter, Robert
Sent: Tuesday, February 13, 2001 9:21 AM
To: Rudins, George; DeHoratiis, Guido; Braitsch, Jay; Carter, Douglas
Subject: FW: Outlines: regional information

Please see the note below -- and especially look at the 2nd page of the attachment on Increased Production of Traditional Energy Resources.

Is there anything we want to add or correct -- in the next 45 minutes!

Bob Porter

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, February 13, 2001 8:26 AM
To: Porter, Robert; PETTIS, LARRY; Breed, William; Conti, John
Subject: FW: Outlines: regional information

(b)(5)

All.

P.S. Use WORD. Software of choice!

Margot

-----Original Message-----
From: Kelliher, Joseph
Sent: Monday, February 12, 2001 10:09 PM
To: Anderson, Margot
Subject: Outlines: regional information

b5

toutregi.doc

29997

Interim Report of the Federal Trade Commission
Midwest Gasoline Price Investigation
July 28, 2000

I. Introduction

The Federal Trade Commission is investigating the causes of the sharp rises in gasoline prices in certain Midwest markets in the spring and early summer of this year. A principal purpose of the investigation is to determine whether those price rises were caused in whole or in part by antitrust violations. This interim report to Congress sets forth the reasons the Commission launched this investigation and provides a status report on the ongoing investigation, including progress to date and a description of the work remaining. In testimony before the House Committees on the Judiciary, Commerce, and Government Reform on June 28, 2000, and the Senate Committee on Energy and Natural Resources on July 13, 2000, Chairman Robert Pitofsky and Bureau of Competition Director Richard G. Parker confirmed the promise made to several members to deliver an interim report to Congress before the end of July.

In the spring and early summer of 2000, gasoline prices increased in markets all over the country. Gasoline prices have long been seasonally cyclical, rising in late spring and early summer as consumer demand increases with the onset of the summer driving season. However, the increases this year in some local markets, particularly in the Midwest, eclipsed those experienced in past years, and were much greater than those experienced in other U.S. markets. Consumers in markets such as Chicago and Milwaukee saw significant price spikes at the retail level, both for the Phase II reformulated gasoline ("RFG"), required under the Clean Air Act for those markets, and for conventional gasoline, which is used in other local markets in the Midwest.

The national average retail price of RFG increased from $1.29 to $1.67 per gallon from November 1999 to June 12, 2000, before declining to $1.61 on July 17, 2000.[(1)] In Chicago, however, the average RFG price rose from $1.85 per gallon on May 30 to $2.13 on June 20, before falling to $1.57 on July 24, 2000.[(2)] From May 30 to June 20 in Milwaukee the average RFG price increased from $1.74 to $2.02, but by July 24 had fallen to $1.48.[(3)]

Conventional gasoline prices in the Midwest also have risen substantially from late 1999 levels, although they also have receded significantly since the highs in mid-June. National average retail prices increased from $1.25 to $1.61 per gallon for conventional gasoline between November 1999 and June 12, 2000, and then eased to $1.51 on July 17, 2000.[(4)] Average conventional gasoline retail prices in the Midwest rose from $1.55 to $1.85 per gallon from May 29 to June 19, 2000, but had decreased to $1.48 by July 17, 2000.[(5)] The price runup was intense, but brief, with prices peaking during the week of June 18-24.

The sheer magnitude of the price increases, their particular intensity in one section of the country, and their occurrence in conventional gasoline as well as in RFG, prompted the Commission's Bureau of Competition to consider the reasons for the price increases and, specifically, whether price fixing or other illegal activity might have occurred. A bipartisan group of Senators and Representatives strongly urged the Commission to investigate these matters.

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In early June 2000, Commission staff began a preliminary investigation, relying initially on publicly available data and consumer complaints. Staff interviewed persons knowledgeable about factors that may have contributed to these price spikes, industry structure, and the regulatory environment. Staff also met with representatives of the Environmental Protection Agency and the Department of Energy. A principal focus of that preliminary investigation, and of the ensuing formal investigation, has been to determine whether there is sufficient evidence to conclude that the antitrust laws have been violated and that such violations caused all or part of the price spikes in the Midwest. Commission staff also have sought information on other potential causes of the price spikes.

The staff's initial inquiry suggested several factors as potential contributors to Midwest gasoline price spikes. The first is the reduced global supply of crude oil. In the second half of 1999, OPEC countries, joined by several non-OPEC oil exporting countries, curtailed the global supply of crude oil. During the same period, worldwide demand for petroleum products increased significantly, as economies in Asia and Europe recovered and economic growth in the United States continued. As a result, worldwide consumption of crude oil has exceeded production, and world and U.S. inventories have been drawn down.[(6)] Refiners responded to the price increases caused by the crude shortage in the same way they had responded to past supply reductions -- by cutting gasoline production and using inventories of gasoline to meet demand, in the expectation that inventories could be replenished when crude oil prices drop as some OPEC members exceed their quotas.[(7)] This series of events contributed to exceptionally tight supply situations in many countries, particularly in the United States.[(8)]

In the last two months, the OPEC countries,[(9)] and Saudi Arabia individually,[(10)] agreed to increase production in an effort to moderate the price of crude petroleum. It remains to be seen whether, when, and to what extent OPEC's and Saudi Arabia's announcements of crude supply increases will reduce prices in the medium to long run. In the short run, crude oil prices have moderated slightly, from $33.55 per barrel on June 23 to $31.31 on July 14.[(11)] OPEC actions likely cannot fully explain the exceptional price spikes that occurred in the Midwest, because such actions would be expected to affect prices in all sections of the United States in a broadly similar way.

A factor specific to the Midwest markets that may have contributed to the price increases was the introduction of EPA Phase II regulations for summer-blend reformulated gasoline in high ozone urban areas. These regulations went into effect on May 1, 2000 at the wholesale level in both Chicago and Milwaukee. The new, more-stringent regulations may have contributed to abnormally low inventories for several reasons. They required that winter-blend gas be drained from storage tanks before the summer-blend supply could be added, which led to lower inventories than usual. According to some reports, summer-blend Phase II RFG is proving more difficult to refine than anticipated, causing refinery yields to be less than expected. The ethanol-based RFG used in Chicago and Milwaukee is reportedly even more difficult to produce. Further, St. Louis entered the RFG program for the first time this year, adding additional demand to an already tight Midwest RFG supply situation.[(12)] Moreover, the recent federal court of appeals decision upholding Unocal's patent for some formulations of RFG may have caused some refineries to change RFG blends to avoid infringement or high royalty payments, leading to production delays and decreased refinery throughput.[(13)] RFG-related issues seem

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unlikely, however, to provide a complete explanation for recent Midwestern gas price increases, because in the Midwest as a whole, conventional gasoline prices rose more dramatically than RFG prices from May to the end of June.(14)

Another possible contributor to the Midwest price increases was the break in the Explorer pipeline in March. Explorer moves refined petroleum products from the Gulf of Mexico through St. Louis to Chicago and other parts of the Midwest.(15) The pipeline break caused a disruption in the supply of gasoline to the already tight Midwest markets. That could have contributed to tight supply and rising prices throughout the region.

Although it is likely that each of these supply factors contributed to the dramatic recent price spikes in the Midwest, no single factor appears from staff's preliminary investigation to be likely to provide a full explanation, and staff does not yet have sufficient information to assess the impact of these factors in combination. Accordingly, it is prudent to investigate the possibility of collusion or tacit coordination, conduct that could be illegal under section 5 of the Federal Trade Commission Act. In order to investigate this and other possible causes of the price spikes in the Midwest, on June 21, 2000, the Commission initiated a formal investigation.(16) Because of the multiplicity of potential interrelated causes, this investigation is likely to consume, at a minimum, another three or four months.

II. The Commission's Investigation

This investigation is being conducted pursuant to the Commission's authority under the Federal Trade Commission Act.(17) The Bureau of Competition is treating it as a top priority matter and has assigned experienced attorneys, economists, investigators and paralegals to the investigation. The Commission chose its Midwest Regional Office, located in Chicago, to spearhead the investigation because they are well-situated to work with local refiners and witnesses and with other law enforcement agencies in the region. Attorneys and economists from the West Coast Regional Office in San Francisco and our headquarters in Washington, D.C. with particular expertise in the oil industry are assisting the Midwest Office. In all, 12 to 14 Commission attorneys, economists, and paralegals are working on the investigation. We are also coordinating our efforts with the Attorneys General of Wisconsin, Illinois, Michigan, Ohio, Indiana, Missouri, Iowa, Minnesota, Kentucky, South Dakota and West Virginia. The Commission has approved the use of compulsory process in this investigation, permitting the issuance of both subpoenas and Civil Investigative Demands, and the taking of depositions under oath.

The objective of the investigation is to consider the causes of the price increases, and determine whether there was any illegal contact, communication, signaling, or understandings among competitors. With regard to proving illegal conduct, the Commission must show more than parallel behavior among market participants. Standing alone, proof that all companies raise prices at the same time is not sufficient evidence of collusion. The courts have held that some "plus factor" must be present to demonstrate that an agreement was reached. Behavior that would be unprofitable "but for" collusion may be evidence that such an agreement exists.

Consistent with the necessity of protecting the confidentiality of information from participants in the investigation, as well as protecting the legal staff's work product, we can report the following information about the investigation to date.(18)

Staff is using process to take testimony and gather evidence from the various entities that refine, transport and distribute gasoline in the Midwest, as well as suppliers and customers and other knowledgeable or affected persons. The Commission issued a first round of subpoenas to nine refiners that supply Midwest markets on June 29. A substantial number of documents have already been produced. In less than a month, staff has received approximately 200 boxes of documents. The bulk of the documents from the first round of subpoenas should be in our hands by the middle of August. Staff is carefully reviewing these documents. The Commission issued a second round of subpoenas to other refiners last week. We have also recently issued CIDs to the refiners, requesting compilations of data and answers to written questions.

We issued another set of subpoenas, this time to the entities that own or control the pipelines serving the Midwest markets, on July 25. We expect responsive documents to begin arriving shortly. Staff also has conducted approximately 15 interviews with market participants, consumers, corporate users of gasoline, and others with knowledge of relevant facts, and is in the process of obtaining industry-wide data from the Oil Price Information Service (OPIS). Staff also conducted a site visit at a refinery on July 20. Once the documentary material has been analyzed, staff will take depositions under oath of key decision-making personnel throughout the gasoline distribution chain in the Midwest. The Commission has retained, and is working with, an outside economic consultant with expertise in this industry.

Our investigation is comprehensive. Prices spiked in the Midwest for one or more reasons. Staff is attempting to identify those reasons. Staff is investigating any and all aspects of the distribution chain in which firms could have colluded to increase prices directly or colluded to reduce capacity or supply, or otherwise to take advantage of a tight supply situation and rising prices. For example, staff is examining supply and inventory evidence from integrated oil companies and independent refineries serving the Midwest to determine if supply was manipulated by agreement or understanding such that insufficient product was available to meet increased summer demand in the Midwest and prices spiked as a result. Staff is also considering whether pipeline capacity constraints and allocation decisions were the result of accidental and market-driven factors or, in whole or in part, the product of a collusive agreement designed to restrict supply in local markets. These are but examples of the kinds of inquiries staff is pursuing. At this point, no conclusions, however tentative, have been reached.

III. Conclusion

Much work remains to be done in order to complete this investigation. The scope of the investigation, the volume of the information that has been or will be produced, and the complexity of the issues under investigation suggest that the investigation likely will consume at least three or four more months. The Commission is treating this investigation as a matter of top priority, but answers in antitrust investigations do not typically come quickly or easily. If staff uncovers reason to believe that an antitrust violation has occurred, however, the Commission will act promptly.

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1. Energy Information Administration, Office of Oil and Gas Daily Price Report (June 12, 2000; July 3, 2000; July 24, 2000). In comparing average RFG prices at different times and different places, it should be noted that RFG requirements may differ between summer and winter and also among localities.

2. EPA Data, RFG-CG Price Information, based on Oil Price Information Service data (June 14, 2000, June 23, 2000).

3. *Id.* During the week of June 19, RFG prices at some Chicago gas stations apparently rose as high as $2.50, although they have since receded. *See* R. Kemper & K. Mellen, "As Pressure Builds, Price of Gas Falls," *Chicago Tribune* (June 23, 2000).

4. EPA Data, RFG-CG Price Information (June 14, 2000, July 10, 2000, July 24, 2000).

5. Energy Information Administration, Motor Gasoline Watch (June 21, 2000, July 10, 2000, July 24, 2000) at 2.

6. Organisation for Economic Cooperation and Development ("OECD"), International Energy Agency, Monthly Oil Market Report (July 11, 2000) at 5, www.iea.org.

7. *Id.* ("Refiners do not really believe today's prices are sustainable, and hesitate to run crude for product restocking.").

8. *Id.* Gasoline stocks in the United States for the fourth quarter of 2000 are estimated to be 37 percent below the level of the fourth quarter of 1999, while Europe's stocks dropped 27 percent in the same period.

9. "OPEC Agrees to Increase Oil Production," *Wall Street Journal* (June 22, 2000) at A3.

10. "Saudi Plan to Raise Oil Output Stirs Up Debate," *Wall Street Journal* (July 5, 2000) at A2.

11. Energy Information Administration, Weekly Petroleum Status Report, Table 13 (July 20, 2000) (WTI-Cushing spot prices).

12. St. Louis received EPA waivers to delay implementation of Phase II RFG until early June, because of a break in the Explorer pipeline which serves the region. St. Louis uses primarily MTBE-based RFG, which many observers believe to be less costly than ethanol-based RFG. St. Louis did not experience price increases as great as those in Chicago and Milwaukee.

13. *Union Oil Co. v. Atlantic Richfield Co.*, 208 F.3d 989 (Fed. Cir. March 29, 2000).

14. According to Energy Information Administration figures, average retail prices throughout PADD II (the Midwestern Petroleum Administration for Defense District) rose 18.9 cents for RFG and 29.4 cents for conventional gasoline from May 29 to June 19. *See* Energy Information Administration, Motor Gasoline Watch (June 21, 2000) at 2.

15. Environment News Service, "Gasoline Spill Threatens Dallas Water Supply" (March 13, 2000).

16. Midwest Gasoline Price Investigation, FTC File No. 001 0174.

17. 15 U.S.C. § 41 et seq. The Commission does not have criminal enforcement authority. The Antitrust Division of the Department of Justice has exclusive responsibility for criminal enforcement of the antitrust laws, pursuant to authority granted under the Sherman Act. 15 U.S.C. § 1 et seq. If staff were to uncover evidence of criminal activity, such as hard-core price fixing, staff would forward the matter to the Antitrust Division.

18. The Commission is statutorily obligated to protect confidential information it receives in a law enforcement investigation. *See* Sections 6(f) and 21 of the Federal Trade Commission Act, 15 U.S.C. §§ 46 (f), 57b-2. In addition, the Commission protects information that reveals the agency's deliberative process, its attorney work product and information whose disclosure could interfere with a law enforcement proceeding. *See* Exemptions 5 and 7 of the Freedom of Information Act, 5 U.S.C. § 552(b)(5), (7); Commission Rule 4.10, 16 C.F.R. 4.10. *See also* Commission Operating Manual § 3.3.3.1 (investigations are ordinarily nonpublic unless the Commission orders otherwise). The Commission may release certain deliberative or investigational information, consistent with the needs of the investigation, and has voted to

do so with this report.

Midwest states probing high gasoline prices

Thursday, June 15, 2000

The Clinton administration said on Wednesday it has not ruled out possible collusion among oil companies as the reason behind a sharp rise in retail gasoline prices in the Midwest.

A rapid run-up in overall U.S. gasoline and crude oil prices has also caught the attention of the Federal Reserve, which is also closely watching for any impact on inflation or economic growth.

Federal officials are investigating whether soaring prices in Chicago, Milwaukee and other Midwest locations are due to free market forces, strict new requirements for cleaner-burning gasoline, or unfair action by U.S. oil refiners, according to Energy Secretary Bill Richardson.

"They're much too high. They're unacceptably high," Richardson said, referring to gasoline prices in the Midwest which have topped $2 a gallon in Chicago and Milwaukee.

"We're trying to determine whether it's market forces or collusion or some glitches with the Environmental Protection Agency's RFG gasoline," Richardson told reporters following a speech at the National Press Club.

The Environmental Protection Agency and the Energy Department met with the region's oil refiners earlier this week to find out why gasoline prices — especially for the new cleaner-burning reformulated gasoline (RFG) — have soared when supplies seem adequate.

Midwest drivers are now paying about 20 cents a gallon more than the U.S. nationwide average price for conventional gasoline, according to the Energy Department.

Illinois Gov. George Ryan, a Republican, asked the state attorney general Wednesday to launch an investigation into gasoline price fraud.

Ryan also said governors in Indiana, Nebraska and Kansas backed his plan to have the federal government temporarily suspend new anti-smog regulations, which have contributed to tight supplies of cleaner-burning gasoline.

Oil companies claim that the new reformulated gasoline, which the EPA required be sold in polluted areas beginning this month, is too expensive and difficult to produce. They say that this has resulted in supply problems and higher prices.

The government is not buying those arguments, pointing out that RFG in cities outside the Midwest is not as expensive.

"The refiners can't explain and others can't explain why gasoline prices are so high in the Midwest and in other parts of the country they're lower," Richardson said. "We're trying to get those answers."

he Federal Reserve is also paying attention to the rapid increase in oil prices during the past month.

Alan Greenspan, chairman of the Fed, is concerned about the risk of inflation posed by steep price increases for oil and low inventories, said Argentine Economy Minister Luis Machinea. He described Greenspan's views to reporters after meeting with the U.S. central banker on Wednesday.

Thomas Hoenig, president of the Federal Reserve Bank of Kansas City, said late Wednesday that the Fed is tracking the rise in gasoline prices and its effect on the economy.

The unexpected climb in U.S. gasoline prices is blamed by many industry experts as a key reason for the run-up in global crude oil prices during the past month. The Organization of Petroleum Exporting Countries is scheduled to meet next week to decide whether worldwide oil supplies are too tight, and more production is needed.

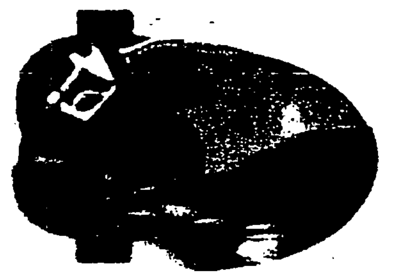
U.S. benchmark gasoline futures contracts trading on the New York Mercantile Exchange finished the day at just over $1.08 a gallon, rising 1.83 cents. During the trading day gasoline reached $1.096 a gallon, the highest since the Gulf War of a decade ago.

The chairman of the House Judiciary Committee asked the Federal Trade Commission last week to investigate if oil companies are gouging Midwest consumers at the pump.

"Even aside from the impact of state and local (fuel) taxes, these prices raise questions as to whether illegal price gouging is occurring," said Republican Rep. Henry Hyde of Illinois.

Gasoline price report cites shortage of cleaner-burning fuel

August 23, 2000
Web posted at: 1:11 p.m. EDT (1711 GMT)



MILWAUKEE (AP) -- A federal report blamed the summer's high gasoline prices in the Chicago-Milwaukee area on short supplies of a new, cleaner-burning gas and said the price fluctuations could continue in future summers.

The report, issued by the Department of Energy's Energy Information Administration, validates the petroleum industry's position that it was not at fault for the rising prices, said Erin Roth, executive director of the Wisconsin Petroleum Council.

But an official at another federal agency, the Environmental Protection Agency, called the report subjective. Robert Perciasepe, the EPA's top air quality official, continued to blame the oil industry for the price hikes.

Gas prices in the Milwaukee and Chicago areas increased 40 percent in May and June, when the federal Clean Air Act mandated a new type of gas to combat air pollution. Prices at one point topped $2 a gallon but have since decreased.

The report cited high crude oil prices, pipeline problems and a special ethanol-blended gasoline used primarily in the Midwest for the regional shortage.

Perciasepe said the report does not explain why the refineries couldn't make enough gas, even though they knew of the new requirement for years.

Of eight refineries serving the Chicago-Milwaukee market, half increased production and half decreased production levels in May and June, the report said.

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MESSAGE BOARD
Rising oil prices

Clinton Administration Looking for Gas-Price Scapegoat

June 21, 2000

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Clinton Administration Looking for Gas-Price Scapegoat

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A Congressional Research Service (CRS) report identified high crude oil prices, the use of ethanol in reformulated gas, and gas pipeline problems among the reasons gas prices are higher in the Midwest than in other parts of the country.

But Vice President Gore, facing growing political fallout from current gas prices, cited a different cause. The vice president suggested yesterday that "big oil is gouging American consumers."

Paying at the pump

The Clinton administration's Federal Trade Commission is investigating the cause of higher gas prices.

"The vice president has a growing political problem because his administration has been asleep at the wheel when it comes to dealing with OPEC," said House Majority Leader Dick Armey. "Instead of acknowledging that his administration has no energy policy, which leaves our nation overly dependent on foreign oil, the vice president is looking for a scapegoat.

"When the going gets tough, Al Gore points fingers," said Armey.

According to the CRS report, several factors contribute to higher Midwest gas prices, including:

- **Higher crude oil prices.** According to the report, "crude acquisition costs have risen by the equivalent of 48 cents per gallon during the past year and a half."
- **Use of Ethanol in Reformulated Gas (RFG).** Reformulated gas, required in certain areas of the country to comply with emission standards, is mixed with ethanol in the Chicago and Milwaukee areas. New RFG requirements that went into effect June 1, "have made it more difficult and costly to make RFG with ethanol."
- **Pipeline Problems.** "Two oil pipelines serving the upper Midwest have been experiencing operational difficulties," reducing gasoline deliveries to the region. "In a tight regional market, supply reductions of this magnitude can be extremely disruptive, and lead to significant price increases."

Read the Congressional Research Service report, "Midwest Gasoline Price Increases." (2mb, PDF format)

Carter, Douglas

From: Friedrichs, Mark
Sent: Tuesday, March 27, 2001 9:56 AM
To: Carter, Douglas; Braitsch, Jay; KYDES, ANDY; 'jkstier@bpa.gov'; Zimmerman, MaryBeth; Terry, Tracy
Subject: FW: Commerce Recommendations for NEP

Follow Up Flag: Follow up
Flag Status: Flagged

DRAFT Commerce Recs.doc

b(5)

-----Original Message-----
From: Anderson, Margot
Sent: Monday, March 26, 2001 3:36 PM
To: Conti, John; Haspel, Abe; Zimmerman, MaryBeth; Lockwood, Andrea; Breed, William; KYDES, ANDY; Whatley, Michael; Carter, Douglas; Braitsch, Jay; Melchert, Elena; Cook, Trevor; Breed, William; 'jkstier@bpa.gov'; York, Michael; Freitas, Christopher; Friedrichs, Mark; Pumphrey, David; Kolevar, Kevin
Cc: Kelliher, Joseph
Subject: FW: Commerce Recommendations for NEP

All,

This is Commerce's wish list of Policy Options for the NEP. Mark F. - can you coordinate a DOE response so we can get to Joe Kelliher? By Wednesday COB? Thanks.

Margot

-----Original Message-----
From: Charles_M._Smith@ovp.eop.gov%internet
[mailto:Charles_M._Smith@ovp.eop.gov]
Sent: Monday, March 26, 2001 3:03 PM
To: Kelliher, Joseph; Kolevar, Kevin; Anderson, Margot;
Juleanna_R._Glover@ovp.eop.gov%internet; Kmurphy@osec.doc.gov%internet;

Sue_Ellen_Wooldridge@IOS.DOI.gov%internet;
Joel_D._Kaplan@who.eop.gov%internet; Keith.Collins@USDA.gov%internet;
Joseph.Glauber@USDA.gov%internet; Galloglysj@State.gov%internet;
McManusmt@State.gov%internet; Michelle.Poche@OST.DOT.Gov%internet;
Patricia.Stahlschmidt@FEMA.gov%internet; Brenner.Rob@EPA.gov%internet;
Symons.Jeremy@EPA.gov%internet; Beale.John@EPA.gov%internet;
MPeacock@omb.eop.gov%internet; Mark_A._Weatherly@omb.eop.gov%internet;
Robert_C._McNally@opd.eop.gov%internet; Jhowardj@ceq.eop.gov%internet;
William_bettenberg@IOS.DOI.gov%internet;
Tom_fulton@IOS.DOI.gov%internet; Kjersten_drager@ovp.eop.gov%internet;
Mleblanc@ceq.eop.gov%internet; Bruce.Baughman@FEMA.gov%internet;
Charles.m.Hess@USACE.army.mil%internet; akeeler@cea.eop.gov%internet;
commcoll@aol.com%internet; Karen_E._Keller@omb.eop.gov%internet;
Carol_J._Thompson@who.eop.gov%internet;
Sandra_L._Via@omb.eop.gov%internet; Megan_D._Moran@ovp.eop.gov%internet;
Janet_P._Walker@opd.eop.gov%internet;
Ronald_L._Silberman@omb.eop.gov%internet;
Lori_A._Krauss@omb.eop.gov%internet; WheelerE@State.gov%internet;
Mark_J._Sullivan@ovp.eop.gov%internet
Cc: Andrew_D._Lundquist@ovp.eop.gov%internet;
Karen_Y._Knutson@ovp.eop.gov%internet; John_Fenzel@ovp.eop.gov%internet
Subject: Commerce Recommendations

Attached are Commerce's draft recommendations for your review

(See attached file: DRAFT Commerce Recs.doc)

Carter, Douglas

From: Carter, Douglas
Sent: Thursday, February 22, 2001 5:03 PM
To: Anderson, Margot
Cc: Braitsch, Jay; Kripowicz, Robert
Subject: RE: NEP news

Margot -

One more from FE (sorry).

b(5)

Doug

-----Original Message-----
From: Anderson, Margot
Sent: Wednesday, February 21, 2001 7:35 PM
To: Cook, Trevor; Scalingi, Paula; PETTIS, LARRY; KENDELL, JAMES; Zimmerman, MaryBeth; Sullivan, John; 'jkstier@bpa.gov'; Kripowicz, Robert; Haspel, Abe; Magwood, William; 'jkstier@bpa.gov'; Whatley, Michael; Braitsch, Jay; Conti, John; Carter, Douglas; KYDES, ANDY; Pumphrey, David; Hart, James
Cc: Kelliher, Joseph
Subject: NEP news

All,

Joe has now received hard copies of chapters 4, 5, and 10 for our review (the ones we didn't do). Sorry but I only had e-copies of 10, rest are hard, so you have to stop by to collect. I'll out them on the PO 7C-034 open area credenza for pick up. Need your comments by Thursday COB - please e-mail me a comments page. I'll compile for Joe. Joe delivered our DOE-led chapters 1, 2, 3, 6, 7, 8 and we will await comments. I'm working on collecting figures and charts. By my calculations, we are still missing chapter 9 (DOT).

The revised outline:

b(5)

Margot

30010

Carter, Douglas

From: Braitsch, Jay
Sent: Thursday, February 22, 2001 4:26 PM
To: Anderson, Margot
Cc: Carter, Douglas
Subject: RE: NEP news

Margot -- More FE Comments

b(5)

Second paragraph under Electricity Imports -

b(5)

-----Original Message-----
From: Anderson, Margot
Sent: Thursday, February 22, 2001 3:33 PM
To: Braitsch, Jay
Subject: RE: NEP news

Yes, got Doug's stuff. Sorry for not checking. I think you are right.

-----Original Message-----
From: Braitsch, Jay
Sent: Thursday, February 22, 2001 3:33 PM
To: Anderson, Margot
Subject: RE: NEP news

b(5)

I think Doug Carter sent you something, and I will be sending some more comments shortly

-----Original Message-----
From: Anderson, Margot
Sent: Thursday, February 22, 2001 3:15 PM
To: Cook, Trevor; Scalingi, Paula; PETTIS, LARRY; KENDELL, JAMES; Zimmerman, MaryBeth; Sullivan, John; 'jkstier@bpa.gov'; Kripowicz, Robert; Haspel, Abe; Magwood, William; 'jkstier@bpa.gov'; Whatley, Michael; Braitsch, Jay; Conti, John; Carter, Douglas; KYDES, ANDY; Pumphrey, David; Hart, James
Cc: Kelliher, Joseph
Subject: RE: NEP news

Can I get a sense of who is going to provide comments by the end of the day on these three chapters? I have NE's (thanks, Trevor) and know EE will comment. Anyone else?

-----Original Message-----
From: Anderson, Margot
Sent: Wednesday, February 21, 2001 7:35 PM
To: Cook, Trevor; Scalingi, Paula; PETTIS, LARRY; KENDELL, JAMES; Zimmerman, MaryBeth; Sullivan, John; 'jkstier@bpa.gov'; Kripowicz, Robert; Haspel, Abe; Magwood, William; 'jkstier@bpa.gov'; Whatley, Michael; Braitsch, Jay; Conti, John; Carter, Douglas; KYDES, ANDY; Pumphrey, David; Hart, James
Cc: Kelliher, Joseph
Subject: NEP news

All,

Joe has now received hard copies of chapters 4, 5, and 10 for our review (the ones we didn't do). Sorry but I only had e-copies of 10, rest are hard, so you have to stop by to collect. I'll out them on the PO 7C-034 open area credenza for pick up. Need your comments by Thursday COB - please e-mail me a comments page. I'll compile for Joe. Joe delivered our DOE-led chapters 1, 2, 3, 6, 7, 8 and we will await comments. I'm working on collecting figures and charts. By my calculations, we are still missing chapter 9 (DOT).

(5)

The revised outline:

30012

b(5) Margot

Carter, Douglas

From: Braitsch, Jay
Sent: Friday, May 25, 2001 9:55 AM
To: Rudins, George; Carter, Douglas; McKee, Barbara; DeHoratiis, Guido; Johnson, Nancy; Juckett, Donald; Pyrdol, John; Freitas, Christopher; Porter, Robert
Cc: Kripowicz, Robert
Subject: National Energy Policy (NEP) Recommended Actions

Recommendations - Summary wit..

b(5)

Carter, Douglas

From: SITZER, SCOTT
Sent: Friday, February 16, 2001 6:06 PM
To: Carter, Douglas
Subject: RE: NEP Coal

NEPCOAL.DOC

Doug,

Thanks for the comments.

b(5)

I have attached that version,
which has already gone to Larry Pettis for transmittal to Margot Anderson.
If
there are any further opportunities for revisions, I will certainly consider
what you sent me.

Scott

-----Original Message-----
From: Douglas Carter_at_HQ-EXCH at X400PO
Sent: Friday, February 16, 2001 1:17 PM
To: Sitzer, Scott
Cc: Robert Kripowicz_at_HQ-EXCH at X400PO; George Rudins_at_HQ-EXCH at X400PO; Robert Porter_at_HQ-EXCH at X400PO
Subject: FW: NEP Coal

Scott -

I wanted to offer you something more concrete than our earlier discussion.
I have marked-up the coal language you drafted for Section 1, and the markup
is attached. Please consider this in your future drafts.

Doug Carter, FE-26, x69684

-----Original Message-----
From: SITZER, SCOTT
Sent: Friday, February 16, 2001 1:34 PM
To: Carter, Douglas
Subject: NEP Coal

Doug,

Attached is a slightly "polished" version of what I sent you yesterday, plus

he
ssociated graphs.

I am supposed to turn this in at noon today, so I would appreciate any

From: Carrier, Paul
Sent: Friday, March 23, 2001 3:57 PM
To: Anderson, Margot; caball@bpa.gov
Cc: 'Stier, Jeffrey K - KN-DC'; Seifert, Roger
Subject: RE: BPA DSI information
Importance: High

Margot,

b(5) b(5)

Paul

-----Original Message-----
From: **Anderson, Margot**
Sent: Friday, March 23, 2001 12:46 PM
To: 'Ball, Crystal A - KN-DC'; Carrier, Paul
Cc: 'Stier, Jeffrey K - KN-DC'; 'Seifert, Roger - KN-DC'
Subject: RE: BPA DSI information

Crystal,

b(5)

Margot

-----Original Message-----
From: Ball, Crystal A - KN-DC ~~[mailto:caball@bpa.gov]~~
Sent: Friday, March 23, 2001 12:35 PM
To: Anderson, Margot; Carrier, Paul
Cc: Stier, Jeffrey K - KN-DC; Seifert, Roger - KN-DC

Subject: RE: BPA DSI information
Importance: High

b(5)

> <<DSI paul info.doc>> <<McCook pr final.doc>>

Kelliher, Joseph

Release

(18)

om: Stephen Sayle [ssayle@dutkogroup.com]
Sent: Thursday, March 22, 2001 4:58 PM
To: Kelliher, Joseph
Subject: to mr. commissioner

A multipollutant regulatory strategy should be established for the power generation sector including:
- Gradually phased in reductions.
- Reform/replacement of NSR
- Use of market-based/emission trading programs
- Inclusion of both existing and new plants and equal treatment for both

The last bullet is the critical one to ensure that: a) we encourage the new generation that is required b) we ensure that the new technologies developed through DOE programs can come into the market.]

I will follow up with a short statement on above tomorrow. Call me with questions

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warming trend may be underway, and that greenhouse gases emissions from human sources may increase the potential impact of global warming. The IPCC recommended that an international agreement be negotiated setting forth a pathway to limit man-made greenhouse gas emissions, especially energy-related carbon dioxide emissions. In 1992, 160 nations heeded this advise and signed the Rio Agreement on Climate Change, formerly known as the "United Nations Framework Convention on Climate Change" (FCCC).

The United States was among the nations to ratify this agreement, which has as its objective stabilizing the atmospheric concentration of greenhouse gases at a level that prevents dangerous anthropogenic interference with the climate system. In ratifying the FCCC, the United States, Europe, Japan and other industrialized countries agreed to take the lead in modifying longer-term trends in anthropogenic emissions, to make best efforts to reduce emissions to 1990 levels by 2000 and to provide technology and funds to developing countries to ensure that emission levels would remain as low as possible—without jeopardizing economic development.

In the months that followed, many U.S. companies, and even entire industry sectors, began to develop programs to increase operating efficiencies, put new technologies in place, and implement business practices aimed at lowering greenhouse gas emissions—while, at the same time, maintaining a growing U.S. economy. These voluntary programs, often in conjunction with government partners, have paid off. Recently, the Department of Energy released a report showing that U.S. greenhouse gas emissions are more than two hundred million tons per year lower than they would be had industry and business not taken these voluntary actions.

A sound long-term climate change policy that complements a sound long-term energy policy must be developed to ensure that the greenhouse gas emissions growth line continues to bend downward while the economic growth curve continues to move upward. Sound climate change policies can make this happen, particularly if these policies:

- Emphasize voluntary action;
- Are cost effective, flexible and focus on long-term solutions that recognize that our economy is built on the availability of reasonably priced energy of all forms;
- Address both cost-effective mitigation actions—such as avoiding emissions through enhanced energy or operating practices—and adaptation to changes that occur for whatever reason;
- Expand research programs that address science, economics and technology development;
- Remove barriers to the deployment of new technologies and encourage rapid deployment through incentives;
- Address the needs of developing nations, including their desire to build their domestic capabilities and grow their economies; and,
- Encourage local action and actions by governments as well as by industry.

Unfortunately, as we enter the 21st Century U.S. climate policy is not based on a long-term strategy. Over the last three years, the US Administration's strategy has been short term and directed at ratifying and implementing the 1997 Kyoto Protocol. This agreement, concluded in December 1997, would require the U.S. and other developed countries to meet mandatory emission reduction targets by 2008-2012. For the United States, the Kyoto Protocol would mean a reduction of greenhouse gas emissions to a level that is seven percent below 1990 levels with additional, but as yet unidentified reductions, after 2012. To meet the initial target the U.S. would have to cut its emissions by 30-35 percent below projected levels. Doing so would be very costly. Most analyses show that reaching this target in such a short time period would reduce the U.S. GDP by several percentage points.

To date, the Kyoto Protocol has not been submitted to the U.S. Senate. If it were, it likely would not be ratified, which is a requirement for the United States to be bound by that agreement. The United States in not alone in its concerns about the impact of the Kyoto Protocol. As of January 2001, no developed country has ratified the agreement. Most nations realize that the Protocol would require significant changes in energy, economic and trade policies and would seriously affect the lives of every citizen. Moreover, the European Union has strenuously resisted elements in the Protocol that theoretically could reduce the cost of compliance. These elements include a proposed emissions trading program, the Clean Development Mechanism (directed toward emissions abatement in developing countries) and land use and forestry programs. Such elements are key to offsetting costly short-term mandatory emission reduction targets. To date, nations are looking for reasonable and cost effective approaches to deal with the climate issue. Increasingly, it is appears likely that most nations will concentrate on new technology development, deployment and transfer to limit greenhouse gas emissions.

In the decade ahead, the federal government should seek to meet the commitment expressed in the FCCC by devoting sufficient scientific resources to determine the maximum atmospheric concentration of greenhouse gases that would "prevent dangerous anthropogenic interference with the climate system" (From Article 2 of the FCCC). Additionally, the U.S. should work with other nations, including developing countries, to establish an equitable long-range plan to prevent the exceeding of this unacceptable concentration. This plan should include all market-based measures that contribute to the ultimate goal, including making maximum use of cost-reducing implementation measures. Moreover, governments should work with industry to develop a broad suite of technology options from which energy users could select in order to meet climate change policy goals in 2050, 2075 and 2100.

Testimony of

Frank K. Turner, President

American Short Line and Regional

Railroad Association

Railroad Infrastructure Policy

House Committee on Transportation and Infrastructure
Subcommittee on Railroads

April 25, 2001

Chairman Quinn and members of the Subcommittee, I am Frank K. Turner, President of the American Short Line and Regional Railroad Association headquartered in Washington, D. C. I appreciate this opportunity to testify about the infrastructure needs of small railroads on behalf of ASLRRA's more than 400 short line and regional railroad members.

I know that in this room, I'm probably preaching to the choir when it comes to pointing out all the good reasons there are for keeping freight on the rails. Railroads help to address this Nation's growing congestion problems by keeping freight off the highways, and when it comes to moving freight, railroads are cost effective, burn less fossil fuel and emit less air pollution per ton-mile than trucks.

Small railroads are doing a big job of relieving highway congestion. More than one-quarter of the carloads of rail freight in this country originate or terminate on a short line or regional railroad. If these small railroads weren't there, this freight would move in trucks - - many of them on rural roads that are not equipped to handle this influx of freight. Public money, and lots of it, will be used to repair the damage all that extra truck traffic creates. Transportation rates in these areas of the country, particularly for bulk commodities such as grain, stone and forest products, will increase because it is more expensive to move these commodities by truckload than by trainload.

Today, the contribution that small railroads make to our national transportation system is threatened by the condition of their infrastructure. In one sense this problem has always been with us. These are light density lines that don't generate enough revenue to make up for the years of deferred maintenance they inherited from their Class I owners. Because of their lower cost structure and their ability to deal with individual shippers in a more flexible way than the Class I's, they have been able to turn money losing lines into marginally profitable lines. They have made enough money to get by, but not enough to make the kind of one-time capital expenditures needed to remain an efficient feeder system for the national rail network.

Today, this problem is coming to a head because of a new element that is completely outside the control of the short line industry – that is the introduction of the heavier 286,000 lb. freight cars that have become the standard for the Class I industry. These cars cause significantly more stress and wear and tear on rail track and bridges. To handle these cars efficiently, light density lines can no longer put off major capital expenditures. If they don't find the money for that investment their lines and their shippers will be effectively disconnected from the nation's main line railroad system.

How Large Is the problem and How Should Congress Confront It?

A recent study by ZETA-TECH Associates concluded that investment in track and structures needed to handle 286,000-pound cars will approach $7 billion on small railroads. ASLRRA and the Federal Railroad Administration funded the ZETA-TECH study jointly under a cooperative agreement. It validated the scope of the "286" problem that had been established in an earlier survey of short lines by the Standing Committee on Rail Transportation of AASHTO (the American Association of State Highway and Transportation Officials).

How should Congress confront this pressing issue? There are two solutions that I would like to discuss today. One involves loans, and the other involves grants. Both are desperately needed. The first is the Railroad Rehabilitation and Improvement Financing Program, commonly referred to as "the RRIF Loan Program." The RRIF Loan Program already exists, but steps need to be taken as soon as possible to make this program work the way Congress intended. The second is H.R. 1020, which would authorize grants of $350 million per year for three years for small railroad infrastructure projects.

1. Implementation of the RRIF Loan Program

Congress enacted the RRIF Loan Program as Section 7203 of the Transportation Equity Act for the 21st Century (TEA-21). The program authorizes the Secretary of Transportation to provide up to $3.5 billion in direct loans and loan guarantees for railroads projects. Of this amount, at least $1 billion is reserved for small railroad projects.

The loan program has been on the books since June of 1998. It took the Administration more than two years to produce implementing regulations. Since the regulations took effect in September of 2000, over a dozen railroad applications have been presented to the Federal Railroad Administration. Not a single one has been approved. This innovative infrastructure financing tool has not yet begun to perform in the way Congress intended.

You have heard from the FRA on this subject and I do not question their good intentions with regard to this program. But the fact is that somehow and somewhere this program is stuck. Somebody in the Department of Transportation needs to get it unstuck.

2. Enactment of H.R. 1020

On March 14th of this year, Congressmen Jack Quinn (R-NY), Bob Clement (D-TN) and Spencer Bachus (R-AL) introduced H.R. 1020, the Railroad Track Modernization Act of 2001. In addition to this strong support from the leadership of this Subcommittee, for which we are grateful, the bill has been sponsored by full Committee Chairman Don Young, by four of the six Subcommittee Chairman and by three of the six Subcommittee ranking Democratic Members.

The bill authorizes General Fund appropriations of $350 million per year for three years for capital grants to rehabilitate, preserve or improve track (including roadbed and bridges) of Class II and Class III railroads. The grants are intended for projects to allow safe and efficient rail operations, particularly when handling 286,000-lb. freight cars. In addition, H.R. 1020 specifically allows grants to be used to supplement the RRIF loan program, to pay credit risk premiums, lower interest rates, or provide a "holiday" on principal payments.

Enactment of H.R. 1020 is a "Win-Win" for Railroads, Employees, Shippers and States.

Certainly the large railroads will benefit from passage of the bill and stabilization of light density rail infrastructure. One way to think of the more than 500 short line and regional railroads in this country is as a very big customer to the mega-carriers. We market business, gather traffic from remote locations and tender it to the AAR member Class I railroads. Our share of the revenues of the traffic we generate and terminate each year is about $3 billion. Theirs is much greater. If we fail, that traffic will be lost to the highways and waterways. At the very least it will move great distances over rural and secondary road systems at great cost to the taxpayers.

This bill is supported by the largest rail union, the UTU. As you have heard, it is opposed by the

Transportation Trades Department of the AFL-CIO, on behalf of its other rail union members. As I understand that opposition, it is based on the fact that many of today's short line railroads began operation as non-union companies and as such the over 25,000 people we employ today do not merit the attention of the federal government. I want to address that issue head on.

First, I served as President of one of the very first spin-off railroads, the MidSouth, during the 1990's. It was fully unionized. I inherited some of the most dilapidated railroad track in the State of Mississippi, track that was well on its way to abandonment. Fortunately we had some profitable segments and we invested every dollar we could from those segments into upgrading those poor segments. We saved the line and we saved the jobs.

Second, while one may argue about why or how short line railroads were originally formed, the fact of the matter is they are increasingly unionized. I have attached to my testimony a copy of the facts as they relate to that matter. Today, 66 percent of small railroad employees are represented by a union. Eight two percent of small railroads with 50 or more employees have a union on the property. One hundred percent of all Class II railroads have at least one union on the property. The trend is clear. As small railroads grow their employees tend to unionize. This legislation will help small railroads grow and prosper and it seems counterproductive to oppose that opportunity in the name of a perceived inequity that occurred twenty years ago.

Third, the railroad unions told you today that preserving the financial stability of Railroad Retirement is one of their most important priorities. Every small railroad worker, whether they are unionized or not, pays into the Railroad Retirement System. Together small railroad employees contribute approximately $206 million annually to the Tier II system. That is not an insignificant amount of money, and everyone that is interested in preserving Railroad Retirement should be interested in preserving and growing this financial contribution to the system.

Fourth, and finally, the Short Line Association has spent considerable time working with the unions, including the TTD in trying to accommodate rail labor's concerns. The sections in the legislation concerning labor protection, Davis-Bacon requirements and disallowing the use of the money for new spin-offs were all included in the bill at the request of rail labor. Not all my members are supportive of these provisions, particularly taking away this funding opportunities for yet to be created short line railroads. But we want to work with rail labor on this legislation and we have tried hard to do so.

Finally, Mr. Chairman, our shippers and the communities in which they are located are beneficiaries of this legislation. Without small railroads our shippers lose their connection to the national railroad system. Our communities lose an important economic development tool. Our states are faced with increasing highway congestion and repair costs.

Meeting the Challenge of Infrastructure

The purpose of the infrastructure program ASLRRA is advocating is to provide a one-time fix for light density railroads so they can meet the new requirements of the 21st Century. The need exceeds $7 billion over the next decade. Our railroads can raise part of the money needed, but they are not big enough or wealthy enough to raise it all for the major rehabilitation that is required to meet the heavy car challenge.

There will be many projects with low returns that will not be suitable for loan financing under the RRIF program. H.R. 1020 provides the missing piece of the puzzle. We believe the Quinn-Clement-Bachus grant program leveraging federal loan funds and state assistance, together with private capital, will help to fix the problem.

If this problem is not fixed, then these railroads will gradually lose their business as their shippers are forced to move to truck or relocate. Once that occurs, these lines will deteriorate and ultimately be abandoned and no amount of federal funding will be able to bring them back. Thousands of current rail shippers will close their doors or put their goods on the highway.

Enactment of H.R. 1020 will be a "win-win" for railroads, employees, shippers and communities across America. I urge your support and prompt passage of this important legislation.

Thank you.

---

* ASLRRA is a non-profit trade association incorporated in the District of Columbia. ASLRRA represents the interests of its more than 400 short line and regional railroad members in legislative and regulatory matters. Short line and regional railroads are an important and growing component of the railroad industry. Today, they operate and maintain 29 percent of the American railroad industry's route mileage (approximately 50,000 miles of track), and account for ten percent of the rail industry's freight revenue and twelve percent of railroad employment (based on statistics for calendar year 1999).

STATEMENT SUBMITTED

BY THE

UNITED STATES NUCLEAR REGULATORY COMMISSION

TO THE

SUBCOMMITTEE ON ENERGY AND AIR QUALITY

OF THE

COMMITTEE ON ENERGY AND COMMERCE

U.S. HOUSE OF REPRESENTATIVES

CONCERNING

THE U.S. NATIONAL ENERGY POLICY: NUCLEAR ENERGY

SUBMITTED BY
DR. WILLIAM D. TRAVERS
EXECUTIVE DIRECTOR FOR
OPERATIONS

Submitted: March 27, 2001

U.S. NUCLEAR REGULATORY COMMISSION

TESTIMONY ON THE U.S. NATIONAL ENERGY POLICY:

NUCLEAR ENERGY

Introduction

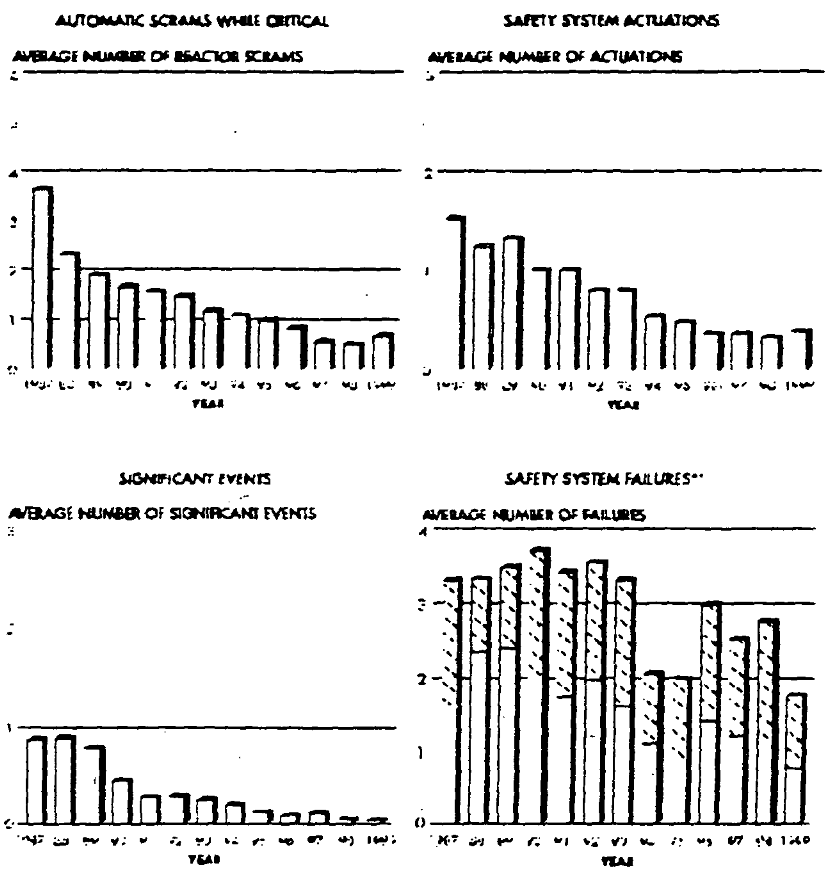
Mr. Chairman, members of the Subcommittee, I am pleased to submit this testimony on behalf of the U.S. Nuclear Regulatory Commission (NRC) regarding the NRC's perspective on how nuclear energy fits into the U.S. National Energy Policy. As the Subcommittee knows, the Commission's mission is to ensure the adequate protection of public health and safety, the common defense and security, and the environment in the application of nuclear technology for civilian use. The Commission does not have a promotional role - - the agency's role is to ensure the safe application of nuclear technology if society elects to pursue the nuclear energy option. The Commission recognizes, however, that its regulatory system should not establish inappropriate impediments to the application of nuclear technology. Many of the Commission's initiatives over the past several years have sought to maintain or enhance safety while simultaneously improving the efficiency and effectiveness of our regulatory system. The Commission also recognizes that its decisions and actions as a regulator influence the public's perception of the NRC and ultimately the public's perception of the safety of nuclear technology. For this reason, the Commission's primary performance goals also include increasing public confidence.

The Commission's primary focus is on safety. The Commission nonetheless recognizes that the quality, predictability, and timeliness of its regulatory actions bear on licensee decisions related to construction and operation of nuclear power plants.

Background

Currently there are 104 nuclear power plants licensed by the Commission to operate in the United States in 31 different states. As a group, they are operating at high levels of safety and reliability.

NRC Performance Indicators; Annual Industry Averages, 1987–1999*



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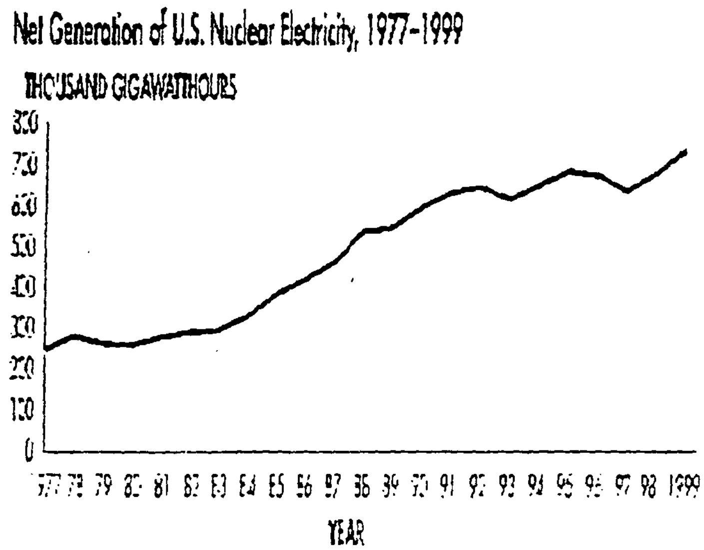
*Calendar year values used for 1986 through 1995. Fiscal year values are used beginning in 1996.

**The hatched areas represent additional data that resulted from reclassification of safety system failures.

These plants have produced approximately 20% of our nation's electricity for the past severa. years and are operated by about 40 different companies. In 2000, these nuclear power plants produced a record 755-thousand gigawatt-hours of electricity.



Improved Licensee Efficiencies (Increased Capacity Factors)

The nation's nuclear electricity generators have worked over the past 10 years to improve nuclear power plant performance, reliability, and efficiency. According to the Nuclear Energy Institute, the improved performance of the U.S. nuclear power plants since 1990 is equivalent to placing 23 new 1000-MWe power plants on line. The average capacity factor[1] for U.S. light water reactors was 86 percent in 1999, up from 63 percent just 10 years ago. T~~he Commission~~ ~~has focused on~~ ensuring that safety has not been compromised as a result of t~~hese industry~~ efforts. Th~~e Commission will continue to carry out its regul~~atory responsibilities in an effective and efficient manner so as not to impede industry initiatives inappropriately.

[1]Capacity factor is the ratio of electricity generated, for the period of time considered, to the amount of energy that could have been generated at continuous full-power operation during the same period.

U.S. Commercial Nuclear Power Reactor Average Capacity Factor and Net Generation

			Net Generation of Electricity	
Year	Number of Reactors Licensed to Operate	Average Annual Capacity Factor (Percent)	Thousands of Gigawatthours	Percent of Total U.S.
1989	109	63	528	19.0
1990	111	68	576	20.5
1991	111	71	613	21.7
1992	110	71	620	22.2
1993	109	73	611	21.2
1994	109	75	640	22.1
1995	109	79	674	22.5
1996	110	77	670	21.9
1997	104	74	628	20.1
1998	104	78	673	22.6
1999	104	86	727	19.8

Electric Industry Restructuring

As the Subcommittee is aware, the nuclear industry has undergone a period of remarkable change. The industry is in a period of transition in several dimensions, probably experiencing more rapid change than in any other period in the history of civilian nuclear power. As deregulation of electricity generation proceeds, the Commission is seeing significant restructuring among the licensees and the start of the consolidation of nuclear generating capacity among a smaller group of operating companies. In part, this change is due to an industry that has achieved gains in both economic and safety performance over the past decade and thus has been able to take advantage of the opportunities presented by industry restructuring. The Commission has established a regulatory system that is technically sound, that is fair, predictable, and reaches decisions with reasonable dispatch.

Initiatives in the Area of Current Reactor Regulation

License Transfers

One of the more immediate results of the economic deregulation of the electric power industry has been the development of a market for nuclear power plants as capital assets themselves. As a result, the Commission has seen a significant increase in the number of requests for approval of license transfers. These requests increased from a historical average of about two or three per year, to 20 - 25 in the past two years.

The Commission has assured that our reviews of license transfer applications, which focus on adequate protection of public health and safety, are conducted efficiently. These reviews sometimes require a significant expenditure of talent and energy by our staff to ensure a high quality and timely result. Our legislative proposal to eliminate foreign ownership review could help to further streamline the process. To date, the Commission believes that it has been timely in these transfers. For example, in CY 2000, the staff has reviewed and approved transfers in periods ranging from four to eight months, depending on the complexity of the applications. The Commission will strive to continue to perform at this level of proficiency even in the face of continued demand.

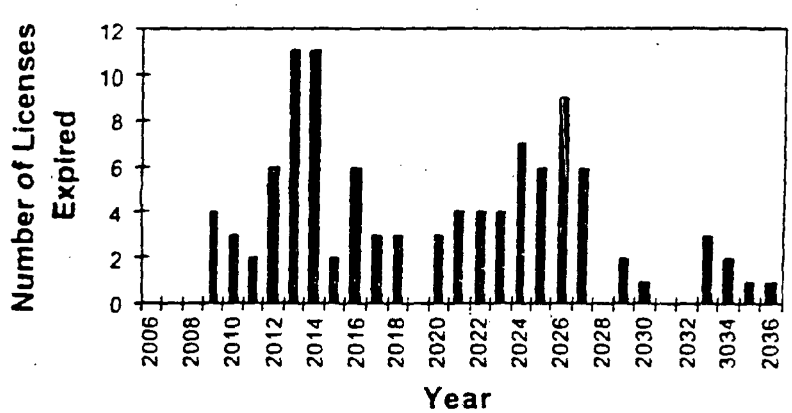
License Renewals

Another result of the new economic conditions is an increasing interest in license renewal that would allow plants to operate beyond the original 40-year term. That term, which was established in the Atomic Energy Act (AEA), did not reflect a limitation that was determined by engineering or scientific considerations, but rather was based on financial and antitrust concerns. The Commission now has the technical bases and experience on which to base judgments about the potential useful life and safe operation of facilities and is addressing the question of extensions beyond the original 40-year term.

The focus of the Commission's review of applications is on maintaining plant safety, with the primary concern directed at the effects of aging on important systems, structures, and components. Applicants must demonstrate that they have identified and can manage the effects of aging so as to maintain an acceptable level of safety during the period of extended operation.

The Commission has now renewed the licenses of plants at two sites for an additional 20 years: Calvert Cliffs in Maryland, and Oconee in South Carolina, comprising a total of five units. The thorough reviews of these applications were completed ahead of schedule, which is indicative of the care exercised by licensees in the preparation of the applications and the planning and dedication of the Commission staff. Applications for units from three additional sites – Hatch in Georgia, ANO-1 in Arkansas, and Turkey Point in Florida – are currently under review. As indicated by our licensees, many more applications for renewal are anticipated in the coming years.

Although the Commission has met the projected schedules for the first reviews, it would like the renewal process to become as effective and efficient as possible. The extent to which the Commission is able to sustain or improve on our performance depends on the rate at which applications are actually received, the quality of the applications, and the ability to staff the review effort. The Commission recognizes the importance of license renewal and is committed to providing high-priority attention to this effort. As you know, the Commission encourages early notification by licensees, in advance of their intentions to seek renewals, in order to allow adequate planning so as not to create unmanageable demands on staff resources.



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Reactor Plant Power Uprates

In recent years, the Commission has approved numerous license amendments that permit its licensees to make relatively small power uprates (approximately 2-7 percent increases in the output of a facility). Collectively, these uprates supplied the electricity equivalent to that from two large power plants (approximately 2,000 MWe). The Commission has received applications for several substantial uprates, and anticipates more within the near term. In addition, some nuclear generators have requested Commission safety review of increasing fuel burnup, thereby extending the operating cycle between refueling outages and thus increasing nuclear plant capacity factors. Such approvals are granted only after a thorough evaluation by Commission staff to ensure that safe operation and shutdown can be achieved at the higher power and increased fuel burnup.

High Level Waste Storage/Disposal (Spent Fuel Storage)

In the past several years, the Commission has responded to numerous requests to approve spent fuel cask designs and independent spent fuel storage installations for onsite dry storage of spent fuel. These actions have provided an interim approach pending implementation of a program for the long-term disposition of spent fuel. The ability of the Commission to review and approve these requests has provided the needed additional onsite storage of spent nuclear fuel, thereby avoiding plant shutdowns as spent fuel pools reach their capacity. The Commission anticipates that the current lack of a final disposal site will result in a large increase in on-site dry storage capacity during this decade.

The Commission is currently reviewing an application for an Independent Spent Fuel Storage Installation on the reservation of the Skull Valley Band of Goshute Indians in Utah.

Certain matters also need to be resolved in order to make progress on a deep geologic repository for disposal of spent nuclear fuel. The Energy Policy Act of 1992 requires the Environmental

Protection Agency (EPA) to promulgate general standards to govern the site, while the Commission has the obligation to implement those standards through its licensing and regulatory process. The Commission has concerns about certain aspects of EPA's proposed approach and is working with EPA to resolve these issues.

Risk-Informing the Commission's Regulatory Framework

The Commission also is in a period of dynamic change as the Agency moves from a prescriptive, deterministic approach towards a more risk-informed and performance-based regulatory paradigm. Improved probabilistic risk assessment techniques combined with over four decades of accumulated experience with operating nuclear power reactors have led the Commission to recognize that some regulations may not serve their intended safety purpose and may not be necessary to provide adequate protection of public health and safety. Where that is the case, the Commission has determined it should revise or eliminate the requirements. On the other hand, the Commission is prepared to strengthen our regulatory system where risk considerations reveal the need.

Perhaps the most visible aspect of the Commission's efforts to risk-inform its regulatory framework is the new reactor oversight process. The process was initiated on a pilot basis in 1999 and fully implemented in April 2000. The new process was developed to focus inspection effort on those areas involving greater risk to the plant and thus to workers and the public, while simultaneously providing a more objective and transparent process. While the Commission continues to work with its stakeholders to assess the effectiveness of the revised oversight process, the feedback received from industry and the public is favorable.

Future Activities

Scheduling and Organizational Assumptions Associated with New Reactor Designs

While improved performance of operating nuclear power plants has resulted in significant increases in electrical output, significant increased demands for electricity will need to be addressed by construction of new generating capacity of some type. Serious industry interest in new construction of ~~nuclear power plants in the U.S. has only recently emerged.~~ As you know, the Commission has already certified three new reactor designs pursuant to 10 CFR Part 52. These designs include General Electric's advanced boiling water reactor, Westinghouse's AP-600 and Combustion Engineering's System 80+. Because the Commission has certified these designs, a new plant order may include one of these approved designs. However, the staff is also conducting a preliminary review associated with other new designs.

In addition to the three already certified advanced reactor designs, there are new nuclear power plant technologies, such as the Pebble Bed Modular Reactor, which some believe can provide enhanced safety, improved efficiency, lower costs, as well as other benefits. To ensure that the Commission staff is prepared to evaluate any applications to introduce these advanced nuclear reactors, the Commission recently directed the staff to assess the technical, licensing, and inspection capabilities that would be necessary to review an application for an early site permit, a license application, or construction permit for a new reactor unit. This will include the capability to review the designs for generation III+ or generation IV light water reactors including the Westinghouse AP-1000, the Pebble Bed Modular Reactor, and the International Reactor Innovative and Secure (IRIS) designs. In addition to assessing its capability to review the new designs, the Commission will also examine its regulations relating to license applications, such as 10 CFR Parts 50 and 52, in order to identify whether any enhancements are necessary.

In order to confirm the safety of new reactor designs and technology, the Commission believes that a strong nuclear research program should be maintained. A comprehensive evaluation of the Commission's research program is underway with assistance from a group of outside experts and from the Advisory Committee on Reactor Safeguards. With the benefit of these insights, the Commission expects to undertake measures to strengthen our research program over the coming months.

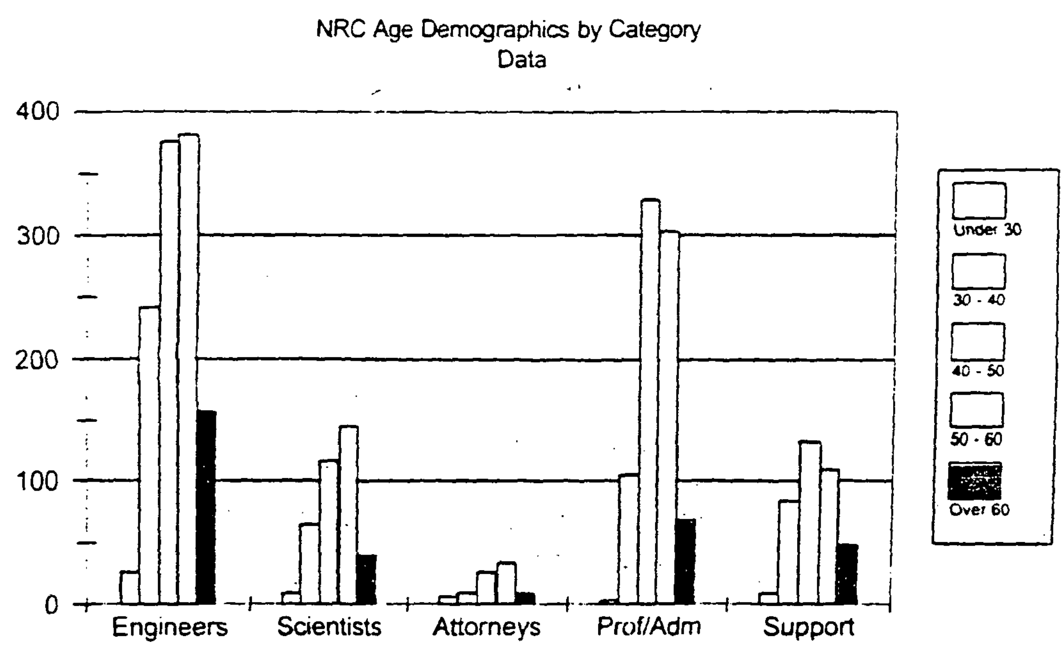
Human Capital

Linked to these technical and regulatory assessments, the Commission is reviewing its human capital to assure that the appropriate professional staff is available for the Commission to fulfill its traditional safety mission, as well as any new regulatory responsibilities in the area of licensing new reactor designs.

In some important offices within the Commission, nearly 25 percent of the staff are eligible to retire today. In fact, the Commission has six times as many staff over the age of 60 as it has staff under 30.

And, as with many Federal agencies, it is becoming increasingly difficult for the Commission to hire personnel with the knowledge, skills, and abilities to conduct the safety reviews, licensing, research, and oversight actions that are essential to our safety mission. Moreover, the number of individuals with the technical skills critical to the achievement of the Commission's safety mission is rapidly declining in the Nation and the educational system is not replacing them. The Commission's staff has taken steps to address this situation, and as a result, is now seeking systematically to identify future staffing needs and to develop strategies to address the gaps. It is apparent, however, that the maintenance of a technically competent staff will require substantial effort for an extended time.

As the Commission is currently challenged to meet its existing workload with available resources, additional resources would be necessary to respond to increased workload which could result from some of the initiatives discussed in this testimony.



NRC Age Demographics by Category
Data
400
300
200
100
0
Engineers
Scientists
Attorneys
Prof/Adm
Support
Under 30
30 - 40
40 - 50
50 - 60
Over 60

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Implications of a National Energy Policy

The Commission has a stake in a national energy policy and has identified areas where new legislation would be helpful to eliminate artificial restrictions and to reduce the uncertainty in the licensing process. These changes would maintain safety while increasing flexibility in decision-making. Although those changes would have little or no immediate impact on electrical supply, they would help establish the context for consideration of nuclear power by the private sector without any compromise of public health and safety or protection of the environment.

Legislation will be needed to extend the Price-Anderson Act. The Act, which expires on August 1, 2002, establishes a framework that provides assurance that adequate funds are available in the event of a nuclear accident and sets out the process for consideration of nuclear claims. Without the framework provided by the Act, private-sector participation in nuclear power would be discouraged by the risk of large liabilities.

Several other legislative changes would be helpful. For example, Reorganization Plan No. 3 of 1970 could be revised to provide the Commission with the sole responsibility to establish all generally applicable standards related to Atomic Energy Act (AEA) materials, thereby avoiding dual regulation of such matters by other agencies. Along these same lines, the Nuclear Waste Policy Act of 1982 could be amended to provide the Commission with the sole authority to establish standards for high-level radioactive waste disposal. These changes would serve to provide full protection of public health and safety, provide consistency, and avoid needless and duplicative regulatory burden.

Commission antitrust reviews could also be eliminated. As a result of the growth of Federal antitrust law since the passage of the AEA, the Commission's antitrust reviews are redundant of the reviews of other agencies. The requirement for Commission review of such matters, which are distant from the Commission's central expertise, should be eliminated.

Elimination of the ban on foreign ownership of U.S. nuclear plants would be an enhancement since many of the entities that are involved in electrical generation have foreign participants, thereby making the ban on foreign ownership increasingly anachronistic. The Commission has authority to deny a license that would be inimical to the common defense and security, and thus an outright ban on all foreign ownership is unnecessary.

With the strong Congressional interest in examining energy policy, the Commission is optimistic that there will be a legislative vehicle for making these changes and thereby for updating the AEA.

Summary

The Commission has long been, and will continue to be, active in concentrating its staffs' efforts on ensuring the adequate protection of public health and safety, the common defense and security, and the environment in the application of nuclear technology for civilian use. Those statutory mandates notwithstanding, the Commission is mindful of the need to: 1) reduce unnecessary burdens, so as not to inappropriately inhibit any renewed interest in nuclear power; (2) maintain open communications with all its stakeholders, in order to seek to ensure the full, fair, and timely consideration of issues that are brought to our attention; and (3) continue to encourage its highly qualified staff to strive for increased efficiency and effectiveness, both in our dealings with all the Commission's stakeholders and internally within the agency.

I look forward to working with the Committee, and I welcome your comments and questions.

The Subcommittee on Railroads

Hearing on

Railroad Infrastructure Policy

TABLE OF CONTENTS(*Click on Section*)

PURPOSE

The Subcommittee will conduct a hearing on the infrastructure policies affecting the nation's railroads on Wednesday, April. 25, 2001, at 10:00 a.m. in Room 2167, Rayburn House Office Building. The Subcommittee will hear testimony both on the implementation of the direct and guaranteed rail and rail-intermodal infrastructure loan program enacted in the 1998 Transportation Equity Act for the 21st Century (TEA 21) and on H.R. 1020, legislation to address smaller railroads' infrastructure needs.

BACKGROUND

Smaller railroads are generally labeled Class II or Class III rail carriers, using Surface Transportation Board (formerly Interstate Commerce Commission) size thresholds based on total annual revenues. Class III carriers each have $20.8 million or less in annual revenues, while the limit for Class II carriers is $259.4 million. Although some smaller railroads have existed for decades, hundreds of new short-line and regional railroads were created following the enactment of the Staggers Rail Act of 1980.

Prior to the Staggers Act reforms that permitted large (Class I) railroads to abandon unproductive lines more easily, deterioration of the rail network, especially on light-density lines serving smaller towns and rural areas, was widespread. The generally higher operating costs of the Class I carriers, combined with low traffic levels, made most light-density lines money-losing enterprises for the large railroads. Prior to 1980, most such lines were shed by Class I carriers (when the ICC regulatory process permitted) through outright abandonment—removing the lines permanently from the rail network.

After 1980, ICC policies and regulations were revised to permit easier sale or lease of marginal lines by Class I railroads to start-up operations. This led to a boom in the formation of Class II and Class III railroads, which include both union and non-union carriers. Some have succeeded financially, while others have not. In the vast majority of cases, the track, roadbed. and other infrastructure acquired by the new smaller operators was already severely deteriorated by Class I standards, but still sufficiently sound to allow low-density (and often low-speed) freight operations. Besides attracting sufficient revenue, a secondary struggle by the smaller freight railroads involved acquiring sufficient capital to maintain and possibly upgrade the quality of the infrastructure inherited from the former owners of these lines. In the early 1990s, an FRA study of smaller railroads' infrastructure needs showed a severe shortfall in the capital resources of these carriers relative to the state of their infrastructure.

In the last several years, a new burden to the marginal infrastructure of smaller railroads has appeared. Class I railroads have begun to add large numbers of more efficient, but far heavier, 286,000-pound cars to their fleets. This increases the operating stresses and wear and tear on smaller railroads' track systems, and depending on the level of deterioration, could entirely prevent operation of "286" cars on certain light-density lines. If such physical embargos were to become widespread, it could result in a non-interoperable rail network, i.e., a rail system where the same fleet of cars cannot operate in all locations on the

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system. Smaller railroads provide approximately 10 per cent of the freight traffic of the major Class I carriers. A recent study, conducted by Zeta-Tech Associates, Inc., under contract to the American Short Line and Regional Railroad Association, concluded that the entire Class II/Class III rail network will require about $6.8 billion in infrastructure upgrades to deal with the heavier rail cars.

H.R. 1020, Railroad Track Modernization Act of 2001

On March 14, 2001, I introduced this bill, with the original cosponsorship of Subcommittee Ranking Member Clement and Mr. Bachus, a Subcommittee Member. Chairman Young has since also cosponsored this legislation, which has been referred to the Transportation and Infrastructure Committee and this Subcommittee.

The bill establishes a program of direct grants to smaller (Class II and Class III) railroads for rehabilitation and improvement of tracks and related structures, to bring the infrastructure up to a level permitting safe and efficient operation, including traffic containing the new heavier 286,000-pound rail cars being adopted as an industry standard by the larger railroads. The general fund authorization level is $350 million per year for FY 2002-2004.

Matching contributions are required under an 80/20 federal/non-federal formula. The nonfederal contribution can be from any non-federal source, and may be cash, equipment, supplies, or other in-kind contribution. Generally, a project must have a 1.0 or higher cost-benefit ratio, with DOT Secretary empowered to waive this standard based on public interest. Track to be rehabilitated or improved must have been operated as a Class II or Class III rail property on date of enactment.

Grant funds must be contractually obligated within 3 full fiscal years after the award of grant. Besides direct funding of track rehabilitation and improvement, grants may also be used to supplement TEA 21 rail loans, including paying credit risk premium for loans, lowering rate of interest, or providing principal payment holidays.

Davis-Bacon standards applicable to Amtrak and transit apply to construction work financed by grants. Any rail employee adversely affected by a grant-funded project will receive standard New York Dock labor protection benefits, under current Surface Transportation Board standards.

DOT is required to conduct a study of future needs of light-density rail lines for federal infrastructure funding, and report to Congress by March 31, 2003.

TEA 21 Rail Infrastructure Loan Program

This program was based on a proposal submitted by the American Short Line and Regional Railroad Association at a 1997 Subcommittee on Railroads hearing (and introduced by Congresswoman Molinari as H.R. 1939). It was enacted as Section 7203 of the TEA 21 (Pub. L. 105-178), and is now codified as Title V of the Railroad Revitalization and Regulatory Reform ("4R") Act, as amended [45 U.S.C. 821-823, 836].

The new program expanded a predecessor loan program established by Section 511 of the "4R" Act. The TEA 21 program created a permanent, revolving authorization for $3.5 billion (face amount) in direct and guaranteed loans for virtually any form of rail or rail-intermodal equipment or infrastructure. This includes freight rail-port connections, commuter and passenger rail facilities, and rail-truck transloading facilities. Of this $3.5 billion revolving authorization, $1 billion was dedicated to the primary benefit of Class II and Class III railroads. The amended TEA 21 loan program retained the labor protection requirements of the 1976 statute.

The TEA 21 program also created two alternative procedures for obtaining a loan. Prior to TEA 21 and after enactment of the Credit Reform Act of 1990, loans under the predecessor program could be obtained only if the credit risk premium (security deposit) for the loan was appropriated as federal funds. The new program permits either an appropriated credit risk premium or one furnished by public or private non-appropriated sources. Thus the second option created the possibility of loans being made on an off-budget basis without any need to become involved in the appropriations process.

Initial Proposals by the Previous Administration

Since TEA 21 was enacted in the summer of 1998, implementation of the loan program by the Federal Railroad Administration has proceeded very slowly. The Administration's first official statement regarding implementation came in the President's FY 2000 Budget (Appendix, p. 767) where the Administration stated its intention (1) to require market rates of interest on all loans made under the program and (2) to require a prior showing that the DOT loan represented a "loan of last resort" following private sector rejections.

The Transportation Committee leadership (Messrs. Shuster, Oberstar, Petri, and Rahall) wrote to Secretary Slater and OMB Director Lew on April 15, 1999, pointing out that neither of these requirements had any legal basis, and that they would cripple the loan program. The letter also complained of the extremely slow implementation of the program to that point. (Unlike entirely new programs like TIFIA, new railroad loan regulations required only a revision of the rules applicable to the predecessor program.)

FRA Proposed Regulations

Notwithstanding these concerns, no rules were proposed until the summer of 1999 [64 Fed. Reg. 27488 (May 20, 1999)].

The proposed regulations deleted the universal market interest rate requirement, which directly contravened statutory language governing interest rates. Nevertheless, the proposed regulations continued to require a showing of "lender of last resort" status through at least two prior rejections of financing from commercial lenders (proposed 49 C.F.R. 260.23(o), 64 Fed. Reg. 27495).

The Committee again responded, this time with a joint comment in the FRA rulemaking docket, dated June 14, 1999, pointing out this and several other deficiencies. When 1999 ended without any final regulations in place, the Committee leadership again wrote to Secretary Slater, pointing out the urgency of having final regulations, so that loan applications could be processed. The leadership's letter of January 3, 2000, pointed out the immediate need for infrastructure funds to address transportation "choke points" such as intermodal port facilities, as well as the urgent need of smaller railroads for upgraded infrastructure to address the "286" car weight problem. Nevertheless, another half-year elapsed without the issuance of regulations.

Final FRA Regulations

FRA issued its final regulations last summer [65 Fed. Reg. 41838 (July 6, 2000)]. Responding to the Committee leadership's repeated comments pointing out the lack of any legal basis for the proposed "lender of last resort" requirement, FRA stated:

While FRA need not be a lender of last resort, it does not intend to replace private funding sources already available to the rail industry. Therefore, in order to establish that private funding on terms necessary to the viability of the applicant's project is not available, FRA will require that railroad applicants provide a letter from a commercial lender denying funding for the project [emphasis added].

This relabeled version of "lender of last resort" is codified at 49 C.F.R. 260.23(o) [65 Fed. Reg. 41844]:

Railroad applicants *must also submit* a copy of application [sic] for financing for the project in the private sector, including the terms requested, from at least one commercial lender, and its response refusing to provide such financing.

Administration delay in promulgating final rules has prevented any loans from being made (including loans that require no appropriation whatever) for more than two and one-half years since enactment of TEA 21.

DOT-OMB Memorandum of Understanding

At a Ground Transportation Subcommittee hearing on July 25, 2000, a memorandum of understanding dated June 23, 2000, between DOT and OMB was made part of the record. In the memorandum, a number of additional requirements were imposed on the loan program. These included (1) not approving any loan over 10 per cent of the annual "cohort" of loans, i.e., holding an early-month application until the entire annual cohort is defined at the end of the year; (2) capping any loan at no more than 6 per cent of the unused authorization, i.e., a constantly declining amount; (3) requiring collateral with a recovery value of 100 per cent of principal and interest, i.e., the equivalent of requiring the collateral for a $100,000 home loan to cover not only the $100,000 loan principal, but the entire 30-year interest stream as well. All of these requirements lack statutory basis, were never subjected to public notice and comment as part of the FRA rulemaking proceeding, and make implementation of the program more difficult. Mr. Rahall has introduced corrective legislation, H.R. 517, to expunge the lender-of-last-resort requirement in the published regulations and the full-recovery collateral requirement in the DOT-OMB memorandum.

On April 6, 2001, Chairman Young, Ranking Member Oberstar, Ranking Subcommittee Member Clement and I wrote to Secretary Mineta, expressing our concern about the complete stagnation of the rail loan program. We urged the Secretary to begin immediately the process of conforming the DOT regulations to the statutory requirements of TEA 21. Not a single loan has been approved under this program since the enactment of TEA 21. The Bush Administration's FY2002 budget proposal (as with all prior Presidential budgets since enactment of TEA 21) includes no funds for appropriated federally provided credit risk premiums to support loans under this program.

WITNESSES
PANEL I

Mr. Mark Lindsey
Chief Counsel and Acting Deputy Administrator
Federal Railroad Administration
Accompanied by:
Mrs. Joanne McGowan
Chief of Freight Programs Division
Mr. Mark Yachmetz
Associate Administrator
Mr. Joseph Pomponio
Attorney-Advisor

Panel II
Mr. Ed Hamberger
President
Association of American Railroads
(statement, appendices)

Mr. Frank Turner
President
American Short Line & Regional Railroad Association

Mr. Patrick K. Gamble
President & CEO
Alaska Railroad Corporation
Accompanied by Mr. Johne Binkley
Chairman of the Board
Alaska Railroad Corporation

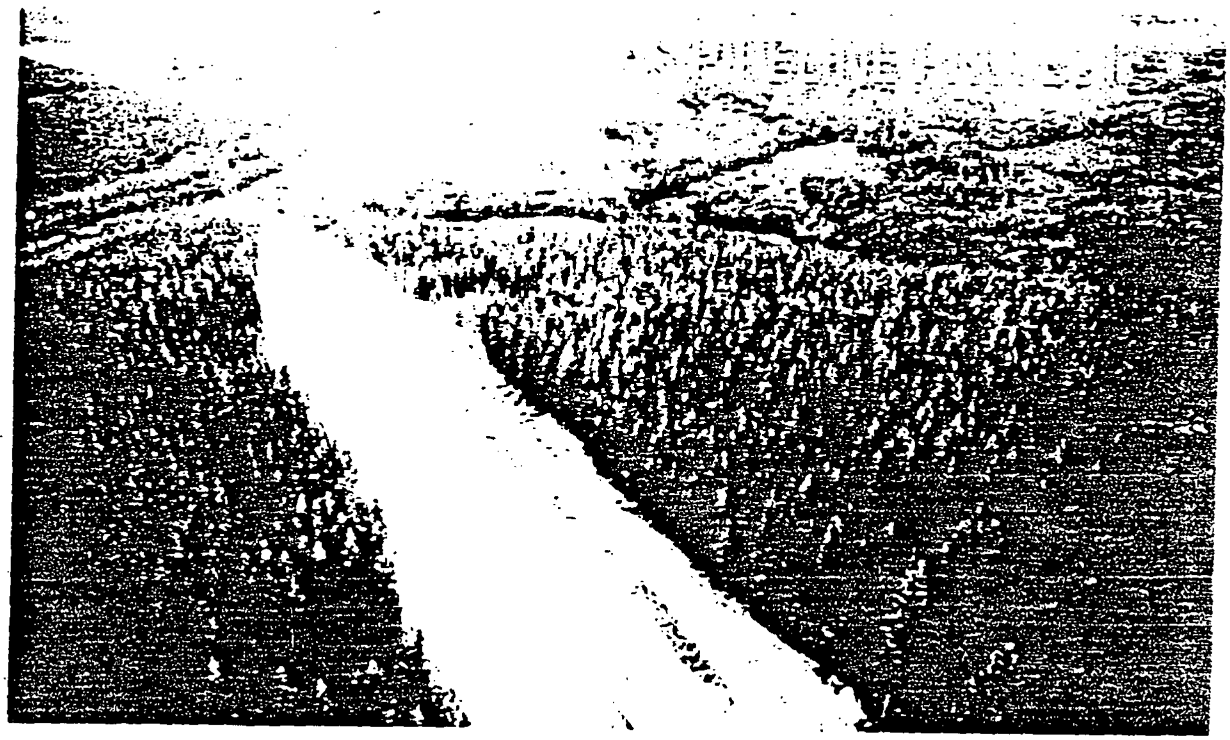
Mr. William W. Millar
President
American Public Transit Associatic

Panel III
Mr. Byron Boyd
President
United Transportation Union

Mr. Donald Griffin
Assistant General Counsel
Brotherhood of Maintenance of Way Employes

ALASKA SENATE LEGISLATURE

Senate Resources Committee



February 5, 2001

Presentation by

John Ellwood
Vice President, Engineering & Operations

Foothills Pipe Lines Ltd.

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Foothills Pipe Lines Ltd. / Alaska Highway Gas Pipeline Project

My name is John Ellwood. I am Vice President, Engineering and Operations at Foothills Pipe Lines Ltd. ("Foothills"). We appreciate your invitation to discuss the transportation of Alaska North Slope natural gas to markets in the lower-48 states through the Alaska Natural Gas Transportation System ("Alaska Highway Project"). I understand that your committee wishes to explore with us the current status of our pipeline project with a particular focus on our permits.

Let me begin by telling you about Foothills. Our company is jointly owned by Westcoast Energy Ltd. ("Westcoast") and TransCanada PipeLines Limited. ("TransCanada"), the two major players in the Canadian gas pipeline business. Our corporate mission is very specific: to build and operate the Alaska Highway Pipeline Project. We were leaders in the project that was conceived twenty-five years ago, and we are just as committed today.

Between Westcoast and TransCanada, we have nearly 100 years of experience in developing, building and operating gas pipeline projects. We have been involved with every major Canadian gas pipeline project built in the last fifteen years.

Our existing pipeline systems provide access to five of North America's largest natural gas markets. Together, these systems have the capability to move fifteen billion cubic feet per day of gas from Western Canada to the consuming markets. Canadian gas accounts for almost 20% of all gas consumed in the United States and all of that gas currently moves through pipelines owned in whole or in part by TransCanada and Westcoast.

This map shows the existing and planned pipeline network of Westcoast and TransCanada.

TransCanada, Westcoast and Foothills have developed leading edge gas pipeline design, construction and operating technology, including expertise in dense phase designs. We are also well known for our development of environmentally sound design, construction and operation practices. We believe that our expertise in northern, remote and difficult terrain gas pipeline construction and operations is second to none.

Building and operating pipelines is our core business.

The Alaska Highway Project is the Alaskan gas pipeline project approved in accordance with the Alaska Natural Gas Transportation Act of 1976 ("ANGTA") in the U.S., the 1978 Northern Pipeline Act in Canada, and the 1977 Agreement Applicable to a Northern Natural Gas Pipeline between the two countries ("U.S./Canada Agreement"). The project is shown in black and green on this map. As approved, the Alaska Highway Project is a 4,800-mile international pipeline project commencing at Prudhoe Bay and terminating in the Midwest and California market areas. It is important to note that the southern part of this pipeline has been constructed and is in full operation. The route for this system parallels the Trans Alaska Pipeline System ("TAPS") to Fairbanks, where it angles southeast, following the Alcan Highway to the Alaska-Yukon border with Canada, down through the Yukon Territory and northern British Columbia, and into Alberta. In Alberta, the pipeline splits into two legs. The Eastern Leg proceeds southwest, crossing the U.S.-Canada border at Monchy, Saskatchewan and terminating near Chicago. The Western Leg proceeds southwest, crossing the U.S.-Canada border near Kingsgate, British Columbia and terminating at a point near San Francisco, California.

Foothills and TransCanada are the two remaining partners of the Alaska Northwest Natural Gas Transportation Company (Alaska Northwest), a partnership formed to construct and operate the Alaska portion of the Alaska Highway Project. In addition, Foothills is the Canadian sponsor of the Alaska Highway Project, and the majority owner and operator of the Canadian portions of the Eastern and Western Legs of the Alaska Highway Project.

Foothills has continuously championed the Alaska Highway Pipeline Project from the very beginning.

The Project is back **"on the list"** of possible solutions to the current North American concerns about high energy prices and the adequacy of natural gas supplies.

At the outset, there are some basic points that we should delineate:

- It is important to remember that this pipeline crosses the territory of two countries with different regulatory and political regimes.

- The Project has a long history, which adds unique attributes. The permits which have been issued are a product of this history and to understand the former requires an appreciation of the latter. Significantly, ANGTA in the U.S. and the Northern Pipeline Act in Canada create expedited procedures for completing the chosen system, the Alaska Highway Project.

- The pipeline permitting process can be very time consuming. In addition to the substantial work already completed on both the Alaskan and Canadian portions of the Alaska Highway Project, the special legislative and regulatory procedures in place in the U.S. and Canada will assist in expediting the construction and initial operation of the Project and keeping unnecessary delays to a minimum.

Historical Background

As I indicated, there are important historical dimensions associated with this project. We might focus on the time frame 1976-1982. Originally there were three competing Alaskan natural gas pipelines proposed. As shown on this map two of the projects were overland pipelines through Alaska and Canada. The third project would have transported gas by pipeline to tidewater, following the route of the"TAPS" pipeline, where the gas would be liquefied and transported to California by liquefied natural gas ("LNG") tankers.

The U.S Congress enacted the Alaska Natural Gas Transportation Act of 1976 with a purpose to provide an expedited process with respect to the selection of a single transportation system for the delivery of Alaska natural gas to the lower forty-eight states and to expedite construction and initial operation of the chosen transportation system.

With respect to the transportation of Alaska North Slope gas to markets in the lower 48 states, ANGTA superseded the usual Natural Gas Act ("NGA") process for granting Federal regulatory authorization to construct and operate a pipeline. ANGTA assigned the responsibility for the overall Alaska pipeline agenda to the President and Congress. Much the same approach was followed in Canada, where the Government took an active role in the decision regarding the Alaska natural gas pipeline. The reason for the creation of this extraordinary authority was that the governments wanted to expedite a cumbersome regulatory approval process in order to move more quickly to a solution.

Prior to 1978, a Canadian Board of Inquiry (The Berger Inquiry) examined a proposal to move Alaska gas across the North Slope and along the Mackenzie Valley. At the same time the National Energy Board ("NEB") held a hearing to determine which of the two overland pipeline routes was acceptable to Canada. Both processes rejected the North Slope route (primarily for environmental reasons) and the NEB recommended the Alaska Highway (Alaska Highway Project) option, being promoted by Foothills. The Berger Inquiry recommended that no pipeline should be built along the Mackenzie Valley for at least a decade and that a pipeline across the northern Yukon should never be built.

During this same period of time the Federal Power Commission (later to become the Federal Energy Regulatory Commission ("FERC") came to a split decision on the question of which route should be selected.

Following the enactment of the ANGTA, the President selected the Alaska Highway route and the Alaska Highway Project with his Decision and Report to Congress on the Alaska Natural Gas Transportation System ("President's Decision" or "Decision").

In 1977 just prior to the President issuing his Decision, the U.S. and Canada signed the U.S./Canada Agreement. This agreement or treaty, established the route, chose the companies who would build and operate the system, established tolling principles, and set the terms and principles to be followed in facilitating the construction and operation of the Alaska Highway Project pipeline. The President's Decision reflected the U.S./Canada Agreement. The Decision and the Agreement were subsequently approved by the U.S. Congress.

In 1978 Canadian Parliament enacted the Northern Pipeline Act. The Act:

1) incorporated all of the terms of the U.S./Canada Agreement

2) issued **statutory certificates** of public convenience and necessity to the respective subsidiaries of Foothills Pipe Lines Ltd.,
3) created the Northern Pipeline Agency to "*facilitate the efficient and expeditious planning and construction of the pipeline*

4) established the methodology and rules for setting the Canadian tolls and tariffs for the pipeline

5) selected the route for the pipeline across Canada and

6) established Terms and Conditions respecting the socio-economic, environmental, construction and operations matters.

The complete Alaska Highway Project is shown on the attached map.

The President's Decision designated Alcan Pipeline, a subsidiary of Northwest Pipeline Company (Northwest), as the party who would construct and operate the Alaska pipeline segment of the Alaska Highway Project. This authority was later assigned to Alaska Northwest, a partnership assembled by Northwest. At one time Alaska Northwest consisted of eleven (11) partners, all subsidiaries of U.S. or Canadian pipeline companies.

Given the magnitude of the pipeline undertaking Alaska Northwest sought to recruit the North Slope Producers to join the project and assist the financing of the pipeline. The Producers expressed a willingness to join but were restricted by the President's Decision that disallowed the producers taking an equity position in the pipeline. In 1981, President Reagan submitted and Congress approved a Waiver of Law package allowing producer participation and including in the project, the North Slope gas conditioning facility.

In 1980, before the Waiver of Law was passed, Alaska Northwest and the Alaska Producers entered into a Cooperation Agreement providing for joint funding of the design and engineering of the Alaska Highway pipeline and the gas conditioning facility. Following the approval of the Waiver of Law, the scope of the Cooperation Agreement was expanded to encompass efforts to achieve the remaining regulatory approvals and to jointly pursue financing arrangements. The two sides anticipated that affiliates of the Producers would join the Alaska Northwest Partnership.

Design, engineering, environmental, financing and regulatory work proceeded along parallel tracks in Alaska and in Canada during this period of time.

As world wide energy supply and demand came back into balance and the "energy crisis" eased, the focus of the pipeline shifted to the pre-building of the southern portions of the Alaska Highway Project. There was a disagreement between Canada and the United States over this issue, primarily as it related to the export of Canadian natural gas to the U.S. market.

The Canadian Government was unwilling to authorize the Pre-build or the gas exports without further assurance from the United States that the entire Alaska Highway Project, including the Alaska segment, would eventually be completed. This assurance was forthcoming in a letter from President Carter to Prime Minister Trudeau, along with a Congressional resolution. As a result the southern Pre-build pipeline section was completed by 1982. This involved constructing 650 miles of 36 and 42 inch pipeline from Caroline, Alberta to Monchy and Kingsgate on the US border. The Pre-build and subsequent expansions were constructed pursuant to the Northern Pipeline Act and it's regulatory regime managed by the Northern Pipeline Agency.

When the Pre-build construction began it was widely anticipated that North American natural gas demand would quickly resume its upward trend. However the market did not recover as anticipated and demobilization of the Alaska Highway Project soon began.

In order to remobilize, we will be required to make modifications and enhancements to various elements of the Alaska Highway Project regime. Pipeline designs will have to be modified so that that the Project can respond to capacity and gas quality requirements of the shippers. We will have to incorporate the latest technology and techniques necessary to ensure that the maximum environmental protection measures are in place. We do not expect any difficulty in introducing these revisions which are so obviously of benefit to all parties.

Recently other parties have raised issues related to payments that might be due to withdrawn partners pursuant to the Alaska Northwest Partnership Agreement. We are confident that if any return of the withdrawn partners' original investment is required it can be resolved within the context of an economically viable project.

Clearly there is a lot of work still to be done. It is very important to understand is that the advantages that come with the unique ANGTA and NPA regulatory regimes far outweigh the alternative of starting from scratch. Using the existing statutes and treaty we can assist in having Alaska natural gas into the U.S. market sooner, with competitive transportation costs and at the same time reducing project risks for all stakeholders.

In our capacity as the managing partner of Alaska Northwest we have maintained the Alaska Highway Project in good standing. We have kept the project alive to ensure that the advantages and benefits of the Project could be used in remobilization plans to expedite construction of the pipeline. We particularly wished to preserve what we see as the "special and unique fast track" regulatory regime.

Foothills and its shareholders have expended time and effort to keep the permits current and to optimize the project design. We do not intend to quit the field now that success is within sight.

The Alaska Permits – Federal

A substantial amount of work has been completed by the Alaska Highway Project sponsors to date. Before discussing the specific permits held by Alaska Northwest it is important to better understand the unique regulatory and legislative framework under which these permits were issued, namely ANGTA.

ANGTA and the President's Decision remain in effect and can be terminated only by another act of Congress. ANGTA does not create a perpetual priority for the Alaska Highway Project. Rather, it establishes a priority designed to ensure that the Alaska Highway Project will be completed and begin initial operation in accordance with the decision of the President and

Congress. Once the Alaska Highway Project is in operation additional projects may be considered under the Natural Gas Act.

In implementing this priority, ANGTA requires that Federal agencies and officers expedite and issue "at the earliest practicable date" all permits and authorizations required by the Alaska Highway Project. In addition, ANGTA provides that applications and requests with respect to permits and authorizations required by the approved system "shall take precedence" over any similar applications and requests. Furthermore, ANGTA limits the discretion of Federal agencies and officers to include in certificates and permits for the Alaska Highway Project any conditions that would obstruct the system's expeditious construction and initial operation.

As required by ANGTA, the FERC in 1977 expeditiously issued a conditional certificate of public convenience and necessity for the Alaska Highway Project. That certificate contains no expiration date and is still in effect today.

In addition, Alaska Northwest holds a federal right-of-way grant issued in 1980 by the Department of Interior's Bureau of Land Management. That grant does not expire until December 2010, and may be renewed at the request of Alaska Northwest.

Furthermore, Alaska Northwest holds two recently extended Clean Water Act wetlands permits issued by the Army Corps of Engineers in coordination with many other agencies. Those permits were extended through September of 2007.

While these various federal permits were issued some time ago, they all are valid today. Indeed, nothing in ANGTA or in the certificates and authorizations issued for the Alaska Highway Project thereunder provides for the expiration of the chosen system's priority because completion of the Alaska segment was postponed until the U.S. domestic market could support it. Rather, the Alaska portion of the Alaska Highway Project has been held in reserve until the need for additional natural gas arises in the Lower 48 states is such that this section can be completed. As sponsors we have actively protected the preserved Alaska segment by maintaining all necessary certificates and permits and actively overseeing the rights-of-way.

We recognize that these certificates and permits need to be "updated" to capture changes in technology, markets and environmental requirements. We will do such updating, and it can be done within the ANGTA framework. To that end, a couple of additional points need to be emphasized before I move on-to the State permits.

- First, ANGTA clearly envisions and provides for the ability to condition and to amend these permits. These powers are subject only to the limitation prohibiting changes in the "basic nature and general route" and actions that will "otherwise" prevent or impair in any significant respect the expeditious construction and initial operation of the Alaska Highway Project.

- Second, the Alaska Highway Project sponsors' requests for both new permits and amendments to existing permits must be given priority under ANGTA. This priority translates into a timing advantage for the Alaska Highway Project.

- Third, the authority of the Office of Federal Inspector, as transferred to the Secretary of Energy, also continues in effect today to expedite and coordinate federal permitting, enforcement of permit conditions, and facilitation and oversight of the construction and initial operation of the U.S. portion of the Alaska Highway Project.

- Fourth, ANGTA also provides for expedited and limited judicial review of actions taken by Federal agencies and officers.

- Finally, the Alaska Northwest Partnership is well along in permitting the Alaska Highway Project.

The Alaska Permits – State of Alaska

On the state side, Alaska Northwest has a pending State of Alaska right-of-way lease application. Recently, we have initiated discussions with the State officials regarding perfecting and processing the pending application. Also at the state level, Alaska Northwest holds certificates of reasonable assurances issued pursuant to Section 401 of the Clean Water Act and a determination of consistency with the Coastal Zone Management Act.

Additional Alaska Permits

While Foothills already holds the major permits necessary to construct the remainder of the Alaska Highway Project, there are additional permits and authorizations that will need to be obtained. For example, the Alaska Highway Project sponsors will need to acquire a permit under the Clean Air Act. However, these additional permits will be procured as the Project proceeds, and such procurement will not cause a delay in the expeditious construction of the Alaska Highway Project.

The Canadian Permits

On the Canadian side, Foothills holds two unique certificates or permits:

- Certificate of public convenience and necessity.
- Yukon right-of-way.

Certificate of Public Convenience and Necessity

The certificate of public convenience and necessity ("certificate") is the Order issued following a successful hearing before the National Energy Board (NEB) of a pipeline application. The information that is required to be filed for hearing purposes is delineated in regulation and includes details about supply and markets, environmental impact assessment, engineering, construction and operations plans and details about connecting pipeline facilities.

The preparation of the required hearing information generally takes one to two years to complete and the length of the hearing will be proportional to the level of controversy surrounding the issues.

Foothills has completed this phase of the process. We have the "certificates" that entitle us to build a pipeline, subject only to terms and conditions set out in the Alaska Highway Project regime.

The "certificates" are statutory. They were issued by the Parliament of Canada when it enacted the Northern Pipeline Act and are in keeping with the principles and intent of the U.S./Canada Agreement.

We acknowledge that the "certificates" were legislated 20 years ago and that some have raised questions about their scope and validity. Others suggest that the certificates are dated and accordingly must be reissued. The "certificates" are valid. We are on solid legal ground in this regard.

Changes to the pipeline design to accommodate new technical issues and improvements have previously have been granted by the Northern Pipeline Agency both at the time of the construction of the original Pre-build facilities and later during the facility expansion.

However, fundamental changes to the Canadian "certificates" would require changes to both the legislation and the treaty. For example another project could not be approved under the Alaska Highway Project regime. Further the Northern Pipeline Act (incorporating the U.S. /Canada Agreement) provides that the route for Alaska natural gas will be along the route set forth in Annex 1 to the U.S. /Canada Agreement i.e. the Alaska Highway route. In the face of the provision of the Northern Pipeline Act and the U.S. /Canada Agreement, a treaty with the force of law, it is difficult to see how the National Energy Board could entertain applications either for alternative pipeline routes for delivery of Alaska gas through Canada or applications by companies other than Foothills following the Foothills highway route for delivery of Alaska gas through Canada.

Given the above we may well ask what remains to be done before the project can proceed?

First of all, we do not have a commercial arrangement negotiated with the Alaska North Slope producers or other shippers. Achieving this commercial arrangement is our number one priority. We are confident that the mutual interests of all sides will ultimately lead to satisfactory arrangements.

Following the successful completion of such a commercial agreement, there are a number of terms and conditions that must be satisfied. These are set out in the Northern Pipeline Socio-economic and Environmental Terms and Conditions. It is our view that the terms and conditions are broad enough to accommodate modern environmental, engineering and construction practices. In fact, we addressed this issue when we pre-built the southern portion of the Alaska Highway Project pipeline.

Detailed design and engineering work also must be completed and approvals must be obtained from the Northern Pipeline Agency. It is this mechanism that I referred to when I indicated that we had a "fast track" regulatory process.

The Yukon Right-of-Way

I will take a few minutes to describe the status of our right-of-way through the Yukon. Foothills has been granted an easement in the Yukon. The current term of the easement is September 2012 and provisions are in place to renew the easement for a further term of 24 years. It is important to note that the easement is protected under the Encumbering Rights provisions of the Umbrella Final agreement which has been signed by the Government of Canada, the Government of the Yukon and the Yukon First Nations. The Final Settlement Agreements that have been negotiated with the Yukon First Nations contain specific provisions relating to the easement. In addition, the compressor stations locations and permanent access to the proposed stations are protected.

What does this mean? From our perspective this translates into certainty of land tenure and a significant timing advantage. Foothills has developed an excellent working relationship with the Yukon First Nations over the years and we are building on that relationship. Like the Canadian "certificates" the easements also constitutes an important asset. An asset not easily replicated.

Conclusion

Let me summarize and focus on some of the key points.

Foothills is a company with real pipelines and real customers.

When combined with our shareholders TransCanada and Westcoast, we transport 20% of all the natural gas consumed in the United States. And we have the know-how and the where-with-all to build the Alaska Highway Pipeline.

We have been involved in this project for 25 years.

We and our former partners have invested heavily to achieve the permits, certificates, rights-of-way and much of the engineering on the Alaska Highway pipeline.

A basic message that I want to leave with you is this, we have a...very unique and solid regulatory framework, it is a very valuable framework in terms of saving money and avoiding costly delays when building a pipeline. It is more than a collection of permits. It is a package, designed specifically to expedite building the Alaska Highway pipeline.

This framework can neither be duplicated nor terminated easily. It is a one-of-a-kind regime. I urge all Alaskans to take full advantage of it.

Finally let me raise one other issue and that is the matter of the pipeline route decision. Before we can move from discussion to action this must be resolved. Anything this committee can do to bring clarity to the routing debate will be a positive development.

Ultimately all stakeholders must find some common ground and go forward.

So where do we go from here?

A commercial agreement between pipelines and producers is the next major mile post for the Project.

Once a satisfactory commercial arrangement is achieved ... the flag drops; from that point on we believe that our regulatory framework will allow "shovels to be in the ground" within 24 months.

This is a very large project. It will involve many companies. It will cost a lot of money and there will be lots of issues to address and benefits to share.

Foothills and its shareholders intend to be major players in the development and operation of this important pipeline and we believe that we bring value to the Project and value to Alaska.

Thank you, and I am now prepared for questions.

Kelliher, Joseph

V (2a.2

From: Charles Ingebretson [cingebretson@bracepatt.com]
Sent: Wednesday, April 25, 2001 5:25 PM
To: Kelliher, Joseph
Cc: Michael Pate; kcullen@wte.org%internet
Subject: Waste-to-energy credit

Joe, here's what I've got on your question yesterday asking how many additional megawatts would be subject to the waste-to-energy tax credit in the year 2011.

As you know, we estimate that the tax credit would stimulate 200 megawatts of additional electricity. However, we estimate that it would be five years before any of this electricity is available. Furthermore, the full 200 megawatts would not be available immediately in the fifth year; additional production would grow to 200 megawatts over a period of time.

For purposes of a rough calculation, we assume that the credit becomes effective in FY 2002 and that no electricity eligible for the credit is generated for 5 years, i.e., until FY 2006. We further assume that for the next 4 years, from FY 2007-2010, the amount of electricity eligible for the credit increases incrementally, by 50 megawatts per year. As a result, the full 200 megawatts of electricity is being produced in FY 2010 through 2012.

If you accept our estimate that the cost of the credit is $27 million per year (assuming 200 megawatts/yr), then the cumulative cost of the credit through the year FY 2012 is something around $121.5 million (which is the sum of $6.75m + $13.5m + $20.25m + $27m + $27m +$27m). Of course, this number will vary if assumptions are different concerning how quickly the tax credit stimulates new production.

On the question of equivalent barrels of oil, Katie advises that IWSA has done an estimate showing that 200 megawatts of electricity displaces, on a Btu basis, 2.8 million barrels of oil per year. She says she'g got the mathematical proofs if you want 'em!

I think I mentioned to you in an earlier phone message that Mike Pate from my office took IWSA in to visit with Treasury Department folks yesterday afternoon. Katie was in that meeting if you have questions. Hope this is helpful.

3076

Kelliher, Joseph

Release

From: Howard Geller [hgeller@aceee.org]
Sent: Tuesday, February 27, 2001 1:29 PM
To: Kelliher, Joseph
Subject: Re: national energy policy

Joe,

I'm glad to hear that. Please remind me--did I send you the full set of policy recommendations (about 12) that we put together, or just a few selected ones? If only a few, I will send you the complete set. Also, did I send you our new report on "Using Targeted Energy Efficiency Programs to Reduce Peak Electrical Demand" by Nadel et al?

Please let me if you would like to meet to go over any of this, and last but not least (as I mentioned over the phone), I really hope the Administration does not proceed in proposing a major cut in energy efficiency and renewable energy R&D and deployment programs for FY02. This is not only a bad idea, but it would be severely criticized by folks like us and I believe it would tarnish the overall effort to advance a broad, balanced set of energy policy initiatives.

Howard

______________________________ Reply Separator ______________________________

Subject: national energy policy
Author: "Kelliher Joseph" <Joseph.Kelliher@hq.doe.gov> at internet-mail
Date: 02/27/2001 1:39 PM

Howard, thanks for the information you sent me. I just wanted to restate
our interest in your specific recommendations on energy efficiency elements
for incorporation in the Administration's national energy policy.

3077

Kelliher, Joseph

From: Slaughter, Bob [Bob_Slaughter@npradc.org]
Sent: Thursday, March 22, 2001 3:52 PM
To: Kelliher, Joseph
Cc: Anthony, Betty; Sternfels, Urvan
Subject: NPRA Recommendations on National Energy Policy

natenergypol2.doc

Joe Kelliher: Attached is a short document which includes NPRA's current thinking as to what changes in national energy policy are needed to help the refining sector.

I would like specifically to highlight three:

One. We believe that the Administration is missing an important opportunity to improve energy policy by not addressing the onroad diesel sulfur rule. This rule will have a greater adverse supply impact than any other in the next five years and should be reviewed. Instead of requiring essentially 100% of onroad diesel output to be reduced from 500 ppm to 15 ppm sulfur by mid-2006, at a cost of $8 billion, the Administration could move the required supply date back to 2008-9 and provide a reduction in the diesel excise tax for 15ppm sulfur diesel sold in advance of the 2008 date. This could provide all the necessary supply for new trucks which need the diesel in 2006-7 (probably only 5% of demand). There are no environmental benefits from using the new diesel in old truck engines, so the program in its current form constitutes massive waste, since those trucks aren't a sufficient force in the market until 2008 at the earliest. This change will help prevent loss of diesel supply and refinery closures which will take place under the rule in its current form. The overall benefits of the program are not reduced. We would like to talk with you more on this.

Two. The EPA's enforcement campaign against U.S. refineries should be halted and reexamined. As you know, it is impossible to build new refineries, so the industry has had to add capacity at existing sites in an attempt to maintain an adequate supply of products for consumers in the past twenty years. Even at that, the industry has been able to keep U.S. capacity only flat over the past decade, so new demand has been met by increased imports of refined products. The Browner EPA launched an extensive and coordinated campaign against the industry, alleging that capacity additions diring the past twenty years were not appropriately permitted. This despite the fact that refinery improvements were made with the knowledge of both state and federal environmental agencies and in keeping with permitting requirements as they were understood at that time. The EPA

has sent section 114 requests, in effect blanket subpoenas, to most refiners, and many are now facing notices of violation and legal action. A
few have settled because they believe that it is easier to pay a fine, sign
a consent decree and move forward than resist. All this comes at a time when federal and state authorities have urged the industry to continue its
herculean efforts to produce product all-out to avoid shortages. EPA's actions are really nothing more than an attempt to discredit the industry
and collect tribute in the form of fines in order to allow refiners to get
on with their business. We believe that everyone in the industry should obey the law, and we believe that they do, often under difficult circumstances. But this activity goes far beyond the pale of reasonable enforcement activity and should cease.

Three. The Unocal patents, recently upheld by a federal court of appeals in
a decision that the Supreme Court let stand, provide no real benefit to the
industry or consumers. The huge royalties granted by a California District
Court-- 5.3/4 cents/gallon--are far in excess of the cost of even the reformulated gasoline program and may well cost consumers over $200 million
per year when implemented. The existence of the payents will increase the
cost of gasoline, reduce supply, and eliminate all of the incentive for overcompliance with environmental regulations. The patent will also make it
even harder to use ethanol in gasoline where ozone problems exist during the
summer months (e.g. Chicago and Milwaukee). The Administration should study
this issue and take steps to put any royalty collections on hold. Otherwise, this situation will affect Midwestern and East Coast gasoline supplies adversely this summer, as it did last year.

The rest of our thinking is attached. Thank you for your call yesterday.
I'm available to discuss these matters with you at any time.

Bob Slaughter
NPRA 202.457.0480 x 152; home (b)(6)

<<natenergypol2.doc>>

3080

National Energy Policy: Themes

- Stable, reliable and affordable supplies of energy and more efficient energy use are essential to maintaining living standards and supporting economic growth.

- Greater emphasis should be placed on diversifying the sources of US energy supplies. Domestic supplies can be enhanced through incentives for improved recovery from existing fields and through improved access to promising acreage.

- Energy policy cannot just focus on the "upstream" sector, i.e. exploration and production. There needs to be a clear understanding that local/regional bottlenecks can occur in producing and distributing feedstocks and products. Further, refineries have been operating near maximum capacity and it has been almost twenty years since a new refinery has been built.

- Petroleum product pipelines are increasingly challenged by the proliferation of "boutique" (area-specific fuels) due to limits on their ability to handle segregated shipments and availability of adequate storage tank capacity. And, additional constraints may arise from the need to gain regulatory approvals for new facilities or pipelines, e.g., the Longhorn pipeline recently agreed not to carry MTBE products in order to gain approval.

- Siting and permitting challenges can seriously delay needed modifications/expansions of existing manufacturing (refining and petrochemical) capacity and constrain additions to downstream infrastructure (e.g. pipelines).

- No single action or single fuel can resolve all energy concerns. The nation needs a balanced mix of policies – which fosters a mix of fuels and balances environmental goals and energy supply concerns.

- A balanced approach to energy policy should examine both demand and supply. Incentives for greater energy efficiency (e.g. through the use of lighter weight materials in vehicles) can play an important role.

- Regulatory programs that distort markets can divert energy supplies from essential (i.e., where there are limited, if any, substitutes) and/or highest valued markets. For example, environmental programs are increasingly drawing natural gas to use in electric generation, thus depriving petrochemical manufacturers of feedstocks or making them so costly that the US petrochemical industry is placed at a competitive disadvantage in global markets.

- Both energy and environmental policy should be based on sound science and the best and most current data available. Cost-benefit analyses and reasonable risk assessment are key tools for choosing the most effective policies to achieve national goals. Regulations should:

    - take into account the cumulative effect of regulations in that sector;
    - set performance goals and avoid mandating specific technologies or setting product specifications;
    - provide adequate leadtime and avoid overlapping requirements wherever possible;
    - provide flexibility through the use of market-based incentives; explicitly evaluate their impact on energy supplies; and

- be fairly and consistently enforced, without retroactive reinterpretation of regulations through enforcement programs.

Potential Energy Policy Improvements

Process

- Require annual study by Secretary of Energy of refining and product distribution infrastructure including assessment of cumulative impact of regulations and specific recommendations for improvements.

- Periodic OMB-led review of supply impact of environmental regulations. Could be included as part of National Energy Policy Plan.

- Require Energy Impact Analysis for new regulations.

- Enhance regulatory certainty, e.g., avoid retroactive reinterpretation of regulations such as in recent EPA NSR enforcement actions.

Incentives

- Accelerated depreciation for clean fuels upgrades.

- Accelerated depreciation for pollution control equipment on stationary sources.

- Tax credits for energy efficiency improvements.

- Investment tax credit for clean fuel capital investments.

- Relief from Alternative Minimum Tax to ensure any incentives offered are not automatically recaptured.

- Excise tax incentives for early introduction of clean fuels, e.g. for low sulfur gasoline and diesel.

Streamlining/Flexibility

- Reasonable guidance on BACT and LAER for Tier 2 gasoline and diesel sulfur programs. Guidance on the emissions level and cost used to determine BACT/LAER requirements. [NOTE: Current draft guidance is not reasonable on this point].

- Allow for trading of credits from mobile source emission reductions with stationary sources.

- Expedited permitting review. Provision of greater certainty that once permits are approved, they will not have to be reopened/renegotiated due to third party intervention.

- Linkage between regulatory implementation deadlines and permitting process, e.g., if delay in permitting despite good-faith efforts to comply, the regulatory deadline is adjusted.

Fuels

- Reassess the sequencing of major fuel regulatory programs. Eliminate the overlap in timing between the gasoline sulfur and diesel sulfur requirements.

- Eliminate 1.5% minimum oxygen requirement for RFG.

- No additional product specifications (such as aromatics caps) that will further constrict gasoline supplies. Focus on performance goals not product specs.

- Reassess mobile source air toxics program to allow greater flexibility through trading among refineries. Reevaluate baseline calculation to remove penalty on refiners who are cleaner than average. Reevaluate standard in light of state programs that limit MTBE use (e.g., Connecticut, New York) which could make regulatory requirement unattainable or very expensive.

- National Academy of Sciences study of MTBE to provide a science-based assessment of impact on groundwater and effectiveness of remediation technologies and including assessment of role of MTBE in meeting gasoline demand.

- Determine appropriate sequencing for any future off-road diesel requirements. Avoid overlap with other regulations, set a reasonable standard for sulfur content.

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50% more energy efficient homes!

Pulte Homes southwest division has utilized technical assistance from DOE's Building America program to create what one residential expert calls "the best production house in the world," which won the 2001 National Association of Home Builders Energy Value Award. In Tucson, Phoenix and Las Vegas, Pulte Homes has worked with DOE to redesign the energy features of its basic models. Using advanced insulation techniques, highly efficient equipment and windows, and right-sized heating and cooling systems, the homes look the same but perform so well they use half the energy for heating and cooling at virtually *no increase in construction costs*. The whole building, systems engineering approach used in Building America allows the builder to add more insulation and more efficient windows while reducing the size of the heating and cooling equipment. The trade-off means no added cost to the builder, better value for the buyer, reduced electric load for the utility, and improved affordability.

For more information, you may contact Randy Foltz or Dave Beck at Pulte Homes (702 256-7900).

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Martin, Adrienne

From: Anderson, Margot
Sent: Wednesday, March 21, 2001 11:57 AM
To: Cook, Trevor
Subject: as we discussed

sec8.doc

Helpful to use redline method if you can/

3778

CORE PRINCIPLES FOR RELIABILITY LEGISLATION

Accreditation of a single North American SRRO

- FERC to approve a single SRRO.
- Procedures for an applicant to apply for SRRO status, and the procedures and requirements for FERC to approve such an application.
- Requires that all system operators be members of the SRRO.
- Provides procedures for the SRRO to modify its procedural, governance and funding rules.

Authority for that SRRO to set and enforce standards

- Specifies the procedures for the SRRO to file with FERC for approval of reliability standards.
- Provides that such proposed standards are to be approved unless FERC finds that they are unjust, unreasonable, unduly discriminatory or preferential, or otherwise not in the public interest.
- Provides that FERC is to give due weight to the technical expertise of the SRRO.
- Gives the SRRO the authority to enforce its standards, subject to FERC review.

Allowance for the SRRO to delegate authority for implementation of standards and enforcement of compliance to regional organizations

- Permits the SRRO to delegate certain authority to regional entities by agreement.
- Such agreements would be filed with FERC for approval.

Funding authority

- Provides for the assessment and allocation of SRRO and regional entity costs to system operators, to be recovered from system users, through a non-bypassable charge.

International arrangements

- Governs international agreements and recognition of the SRRO.

Anti-trust protections

- Provides for a rebuttable presumption that activities undertaken under the Act are in compliance with the antitrust laws.

Transition mechanism

- Provides for the optional filing with FERC of existing standards by NERC and regional councils prior to approval of an SRRO, which FERC could approve and enforce.

JT I

b5

Kelliher, Joseph

From: Dana Contratto [dcontratto@msn.com]
Sent: Thursday, March 22, 2001 12:04 AM
To: Kelliher, Joseph
Subject: RE: national energy policy

Importance: High

Joe,

Of course, if I were King we would already have a national energy policy that would have kept California out of the mess in which it now finds itself. Also, I was pleased to see that the Secretary is now saying that OPEC pricing is the action of a cartel and not market forces -- he is certainly on the right track.

Now, to the point of your question, what to do about pipeline certification and pricing. Frankly, I do not recall much of the gas title that was basically dropped from the 92 EPAct. I do recall that much of what the pipelines wanted was on the pricing side, and not just market pricing, but "cost of service" at such, in my view, ridiculous things as replacement pricing, which is basically "profiteering" of the worst kind because it is with the government as "regulator," and market pricing for existing systems irrespective of the pipeline's market power. Anyway, enough bemoaning what he pipelines will seek.

As to certification or licensing, the process is both mature and daunting. There seems to be little that can be done in terms of reducing intervenors rights (such as restricting intervention from competing fuels, like oil jobbers -- by the way, this notion once "had legs", but I would not pursue it for the simple reason that, while one could theorectically restrict the rights of such intervenors, the EIS process still requires the consideration of alternatives and that, perforce, brings in the alternative fuel issues anyway). There are some things around the edges that could be done, such as what FERC just proposed for California service -- that is, raising the dollar level for facilities built under blanket certificates, which helps in terms of adding compression. In short, I do think that the certificate process is seriously process constrained, but, absent suggestions that would be highly controversial, I do not see much procedurally that can be done in terms of really expediting it. (Remember the ill-fated Optional Expeditied Certificate procedure -- basically saying that if the pipeline agrees to "take the economic risk" of the project, it could proceed much more rapidly. nfortunately, pipeline certificates come with rights of eminent domain and allowing such on an expedited basis is truly problematic, if not at the

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certificate stage itself, then when the pipeline goes to court to condemn property and is challenged on public benefit grounds.)

So, having said that, what can be done. Here are some ideas: First, while the process itself is constrained with environmental assessments and EISs, it seems to me that the government could do something to make sure that the process is not resource constrained. In other words, my guess is that more resources at FERC for some period of time -- perhaps outside contractors so as not to commit to higher staffing for the next century -- could expedite pipeline certificates substantially. Presently, my recollection is that FERC costs the government nothing -- that is, the fees and charges generated by FERC are sufficient to cover its costs of operations. Nonetheless, the idea is that if it takes two FERC staff people two weeks to review an application, four staff people should be able to do so in less time. Granted that this increase in FERC resources might cost the surplus some few tens of millions of dollars, it probably could have a significantly beneficial impact on the time it takes to complete a certificate application review.

Second, and in a similar vein, I do not think that FERC has the power to control other agencies that are necessary to process a pipeline certificate -- for example, the Corps of Engineers for water crossings or dredge and fill permits or DOI's Fish and Wildlife for endangered species determinations. I believe that one idea floated in the past was for FERC to be the central clearing agency. The problem is, what do you do when the agencies do not comply with FERC deadlines -- it is politically unacceptable to say, well, if you do not meet the deadline, whatever you are looking into will be deemed done and acceptable. So, again, this is another kind of process constraint that in my view can also be viewed as a resource constraint -- that is, if more money could be put into the process to hire (again, perhaps contracting out is the real answer) qualified people to get the job done in a more time manner, it could in fact be done in a more timely manner. So, again, increase the resources as necessary to move pipeline certificate applications and related requirements of other agencies in a faster manner. Do not compromise the substance, just get it done quicker with more resources.

Finally, the norm for gas transmission operating pressures in the U.S. is around 1000 psi. In other parts of the world, pipelines are operating at higher pressures -- the Bolivia-Brazil line is 1400 psi. With higher pressures, more gas moves. Obviously, some pipelines could not handle such higher pressures, but new pipelines could be built to move more gas at such higher pressures. This is an idea I would take up with INGAA, also with the obvious first order being safety.

As mentioned above, rates, that is money and returns on equity, are
central
to incentives. To my mind, rolled in pricing is problematic from the
outset
unless there are truly system benefits that are fairly evenly spread in
terms of better service or lower rates. Incremental pricing in my mind
should, however, be the order of the day -- that is, those who use the
incremental capacity created by the project or system enhancement pay
for
it. The good thing about this is that it quells complaints by existing
customer, which can kill projects. Another interesting pricing idea is
to
allow market rates on new projects where there are more than one
competing
pipeline for the customers and where the pipeline does not possess
market
power -- obviously, it is quite difficult for a pipeline to possess
market
power when it is trying to enter a new market. The downside to this
from an
existing coustomer perspective is, how do we know that the pipeline will
really be able to operate at such prices -- that is, what happens when
it
fails and tries to put the cost on other customers or tries to increase
rates to cover its higher cost of capital for having a large failed
project.
Having said this, I still believe that negotiated, market rates on new
projects would greatly enhance the pipelines' incentives to build new
projects. The customers are usually large and sophisticated and do not
need
government protection from the hands of market power because the
pipeline
just does not have market power in these circumstances where it is
trying to
build new facilities to serve new customers. The key, to me, is to
require
the pipeline to bear the risk of failure on such projects.

So, there you have it. The best of my quick thinking at the moment
recognizing that I am also on vacation in St. Lucia at the moment. I
will
be back next week and be able to discuss this or other items further
with
you if you want. By the way, as to ANGTS, I have not reviewed it for
some
time. However, anything done in 1976 probably should be revisited to
see if
it is still viable. Sorry I do not have more at this time to offer on
that
subject.

Good luck.

Dana

-----Original Message-----
From: Kelliher, Joseph [mailto:Joseph.Kelliher@hq.doe.gov]
Sent: Sunday, March 18, 2001 5:44 PM
To: 'Dana Contratto'
Subject: national energy policy

If you were King, or Il Duce, what would you include in a national
energy

8-5

policy, especially with respect to natural gas issues? Should I look at any
of the gas pipeline provisions in the House EPAct bill that were dropped in
conference? I am just looking for your immediate thoughts, please do not
put a lot of time into this. I am working up the policy elements, and am
less confident of my judgement on gas pipeline issues than other areas, and
thought I would pick your brain. With respect to the Alaska Natural Gas
Transportation Act cf 1976, I am operating a suspicion that law would have
to be substantially amended to serve as a basis for licensing an Alaskan gas
pipeline. Do you agree?

B-5

4637

Braitsch, Jay

From: Como, Anthony
Sent: Thursday, February 22, 2001 11:18 AM
To: Braitsch, Jay

Per George's request, I've attached some comments on the National Energy Policy paper he gave me this morning.

comments to jay.wpd

The White House

Office of the Press Secretary

For Immediate Release September 27, 1993

Fact Sheet
Nonproliferation And Export Control Policy

The President today established a framework for U.S. efforts to prevent the proliferation of weapons of mass destruction and the missiles that deliver them. He outlined three major principles to guide our nonproliferation and export control policy:

- Our national security requires us to accord higher priority to nonproliferation, and to make it an integral element of our relations with other countries.

- To strengthen U.S. economic growth, democratization abroad and international stability, we actively seek expanded trade and technology exchange with nations, including former adversaries, that abide by global nonproliferation norms.

- We need to build a new consensus - embracing the Executive and Legislative branches, industry and public, and friends abroad - to promote effective nonproliferation efforts and integrate our nonproliferation and economic goals.

The President reaffirmed U.S. support for a strong, effective nonproliferation regime that enjoys broad multilateral support and employs all of the means at our disposal to advance our objectives.

Key elements of the policy follow.

Fissile Material

The U.S. will undertake a comprehensive approach to the growing accumulation of fissile material from dismantled nuclear weapons and within civil nuclear programs. Under this approach, the U.S. will:

- Seek to eliminate where possible the accumulation of stockpiles of highly-enriched uranium or plutonium, and to ensure that where these materials ~~already~~ exist they are subject to the highest standards of safety, security, and international accountability.

- Propose a multilateral convention prohibiting the production of highly-enriched uranium or plutonium for nuclear explosives purposes or outside of international safeguards.

- Encourage more restrictive regional arrangements to constrain fissile material production in regions of instability and high proliferation risk.

- Submit U.S. fissile material no longer needed for our deterrent to inspection by the International Atomic Energy Agency.

- Pursue the purchase of highly-enriched uranium from the former Soviet Union and other countries and its conversion to peaceful use as reactor fuel.

- Explore means to limit the stockpiling of plutonium from civil nuclear programs, and seek to minimize the civil use of highly-enriched uranium.

- Initiate a comprehensive review of long-term options for plutonium disposition, taking into account technical, nonproliferation, environmental, budgetary and economic considerations. Russia and other nations with relevant interests and experience will be invited to participate in this study.

The United States does not encourage the civil use of plutonium and, accordingly, does not itself engage in plutonium reprocessing for either nuclear power or nuclear explosive purposes. The United States, however, will maintain its existing commitments regarding the use of plutonium in civil nuclear programs in Western Europe and Japan.

Export Controls

To be truly effective, export controls should be applied uniformly by all suppliers. The United States will harmonize domestic and multilateral controls to the greatest extent possible. At the same time, the need to lead the International policy interests may justify unilateral export controls in specific cases. We will review our unilateral dual-use export controls and policies, and eliminate them unless such controls are essential to national security and foreign policy interests.

We will streamline the implementation of U.S. nonproliferation export controls. Our system must be more responsive and efficient, and not inhibit legitimate exports that play a key role in American economic strength while preventing exports that would make a material contribution to the proliferation of weapons of mass destruction and the missiles that deliver them.

Nuclear Proliferation

The U.S. will make every effort to secure the indefinite extension of the Non-Proliferation Treaty in 1995. We will seek to ensure that the International Atomic Energy Agency has the resources needed to implement its vital safeguards responsibilities, and will work to strengthen the Iaea's ability to detect clandestine nuclear activities.

Missile Proliferation

We will maintain our strong support for the Missile Technology Control Regime. We will promote the principles of the Mtcr Guidelines as a global missile nonproliferation norm and seek to use the Mtcr as a mechanism for taking joint action to combat missile proliferation. We will support prudent expansion of the Mtcr's membership to include additional countries that subscribe to international nonproliferation standards, enforce effective export controls and abandon offensive ballistic missile programs. The United States will also promote regional efforts to reduce the demand for missile capabilities.

The United States will continue to oppose missile programs of proliferation concern, and will exercise particular restraint in missile-related cooperation. We will continue to retain a strong presumption of denial against exports to any country of complete space launch vehicles or major components.

The United States will not support the development or acquisition of space-launch vehicles in countries outside the Mtcr.

For Mtcr member countries, we will not encourage new space launch vehicle programs, which raise questions on both nonproliferation and economic viability grounds. The United States will, however, consider exports of Mtcr-controlled items to Mtcr member countries for peaceful space launch programs on a case-by-case basis. We will review whether additional constraints or safeguards could reduce the risk of misuse of space launch technology. We will seek adoption by all Mtcr partners of policies as vigilant as our own.

Chemical and Biological Weapons

To help deter violations of the Biological Weapons Convention, we will promote new measures to provide increased transparency of activities and facilities that could have biological weapons applications. We call on all nations -- including our own -- to ratify the Chemical Weapons Convention quickly so that it may enter into force by January 13, 1995. We will work with others to support the international Organization for the Prohibition of Chemical Weapons created by the Convention.

Regional Nonproliferation Initiatives

Nonproliferation will receive greater priority in our diplomacy, and will be taken into account in our relations with countries around the world. We will make special efforts to address the proliferation threat in regions of tension such as the Korean peninsula, the Middle East and South Asia, including efforts to address the underlying motivations for weapons acquisition and to promote regional confidence-building steps.

In Korea, our goal remains a non-nuclear peninsula. We will make every effort to secure North Korea's full compliance with its nonproliferation commitments and effective implementation of the North-South denuclearization agreement.

In parallel with our efforts to obtain a secure, just, and lasting peace in the Middle East, we will promote dialogue and confidence-building steps to create the basis for a Middle East free of weapons of mass destruction. In the Persian Gulf, we will work with other suppliers to contain Iran's nuclear, missile, and Cbw ambitions, while preventing reconstruction of Iraq's activities in these areas. In South Asia, we will encourage India and Pakistan to proceed with multilateral discussions of nonproliferation and security issues, with the goal of capping and eventually rolling back their nuclear and missile capabilities.

In developing our overall approach to Latin America and South Africa, we will take account of the significant nonproliferation progress made in these regions in recent years. We will intensify efforts to ensure that the former Soviet Union, Eastern Europe and China do not contribute to the spread of weapons of mass destruction and missiles.

Military Planning and Doctrine

We will give proliferation a higher profile in our intelligence collection and analysis and defense planning, and ensure that our own force structure and military planning address the potential threat from weapons of mass destruction and missiles around the world.

Conventional Arms Transfers

We will actively seek greater transparency in the area of conventional arms transfers and promote regional confidence- building measures to encourage restraint on such transfers to regions of instability. The U.S. will undertake a comprehensive review of conventional arms transfer policy, taking into account national security, arms control, trade, budgetary and economic competitiveness considerations.

# # #

The White House

Office of the Press Secretary

For Immediate Release September 27, 1993

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National Energy Policy: Themes

- Stable, reliable and affordable supplies of energy and more efficient energy use are essential to maintaining living standards and supporting economic growth.

- Greater emphasis should be placed on diversifying the sources of US energy supplies. Domestic supplies can be enhanced through incentives for improved recovery from existing fields and through improved access to promising acreage.

- Energy policy cannot just focus on the "upstream" sector, i.e. exploration and production. There needs to be a clear understanding that local/regional bottlenecks can occur in producing and distributing feedstocks and products. Further, refineries have been operating near maximum capacity and it has been almost twenty years since a new refinery has been built.

- Petroleum product pipelines are increasingly challenged by the proliferation of "boutique" (area-specific fuels) due to limits on their ability to handle segregated shipments and availability of adequate storage tank capacity. And, additional constraints may arise from the need to gain regulatory approvals for new facilities or pipelines, e.g., the Longhorn pipeline recently agreed not to carry MTBE products in order to gain approval.

- Siting and permitting challenges can seriously delay needed modifications/expansions of existing manufacturing (refining and petrochemical) capacity and constrain additions to downstream infrastructure (e.g. pipelines).

- No single action or single fuel can resolve all energy concerns. The nation needs a balanced mix of policies – which fosters a mix of fuels and balances environmental goals and energy supply concerns.

- A balanced approach to energy policy should examine both demand and supply. Incentives for greater energy efficiency (e.g. through the use of lighter weight materials in vehicles) can play an important role.

- Regulatory programs that distort markets can divert energy supplies from essential (i.e., where there are limited, if any, substitutes) and/or highest valued markets. For example, environmental programs are increasingly drawing natural gas to use in electric generation, thus depriving petrochemical manufacturers of feedstocks or making them so costly that the US petrochemical industry is placed at a competitive disadvantage in global markets.

- Both energy and environmental policy should be based on sound science and the best and most current data available. Cost-benefit analyses and reasonable risk assessment are key tools for choosing the most effective policies to achieve national goals. Regulations should:

  - take into account the cumulative effect of regulations in that sector;
  - set performance goals and avoid mandating specific technologies or setting product specifications;
  - provide adequate leadtime and avoid overlapping requirements wherever possible;
  - provide flexibility through the use of market-based incentives; explicitly evaluate their impact on energy supplies; and

- be fairly and consistently enforced, without retroactive reinterpretation of regulations through enforcement programs.

Potential Energy Policy Improvements

Process

- Require annual study by Secretary of Energy of refining and product distribution infrastructure including assessment of cumulative impact of regulations and specific recommendations for improvements.

- Periodic OMB-led review of supply impact of environmental regulations. Could be included as part of National Energy Policy Plan.

- Require Energy Impact Analysis for new regulations.

- Enhance regulatory certainty, e.g., avoid retroactive reinterpretation of regulations such as in recent EPA NSR enforcement actions.

Incentives

- Accelerated depreciation for clean fuels upgrades.

- Accelerated depreciation for pollution control equipment on stationary sources.

- Tax credits for energy efficiency improvements.

- Investment tax credit for clean fuel capital investments.

- Relief from Alternative Minimum Tax to ensure any incentives offered are not automatically recaptured.

- Excise tax incentives for early introduction of clean fuels, e.g. for low sulfur gasoline and diesel.

Streamlining/Flexibility

- Reasonable guidance on BACT and LAER for Tier 2 gasoline and diesel sulfur programs. Guidance on the emissions level and cost used to determine BACT/LAER requirements. [NOTE: Current draft guidance is not reasonable on this point].

- Allow for trading of credits from mobile source emission reductions with stationary sources.

- Expedited permitting review. Provision of greater certainty that once permits are approved, they will not have to be reopened/renegotiated due to third party intervention.

- Linkage between regulatory implementation deadlines and permitting process, e.g., if delay in permitting despite good-faith efforts to comply, the regulatory deadline is adjusted.

Fuels

- Reassess the sequencing of major fuel regulatory programs. Eliminate the overlap in timing between the gasoline sulfur and diesel sulfur requirements.

- Eliminate 1.5% minimum oxygen requirement for RFG.

- No additional product specifications (such as aromatics caps) that will further constrict gasoline supplies. Focus on performance goals not product specs.

- Reassess mobile source air toxics program to allow greater flexibility through trading among refineries. Reevaluate baseline calculation to remove penalty on refiners who are cleaner than average. Reevaluate standard in light of state programs that limit MTBE use (e.g., Connecticut, New York) which could make regulatory requirement unattainable or very expensive.

- National Academy of Sciences study of MTBE to provide a science-based assessment of impact on groundwater and effectiveness of remediation technologies and including assessment of role of MTBE in meeting gasoline demand.

- Determine appropriate sequencing for any future off-road diesel requirements. Avoid overlap with other regulations, set a reasonable standard for sulfur content.

Kelliher, Joseph

b6

From: Anderson, Margot
Sent: Saturday, March 24, 2001 11:04 AM
To: Kelliher, Joseph
Subject: FW: NPRA Recommendations on National Energy Policy

Did I send this to you? PO guys took a look at the NPRA recommendations.

b(5)

-----Original Message-----
From: Breed, William
Sent: Friday, March 23, 2001 5:05 PM
To: Anderson, Margot
Cc: McNutt, Barry
Subject: RE: NPRA Recommendations on National Energy Policy

After talking with Barry, here are some comments:

Comments on NPRA energy policy ideas (23 MAR 01)

b(5)

b5

b(5)

William Breed
Acting Director, Office of Energy Efficiency,
Alternative Fuels, and Oil Analysis (PO-22)
202-586-4763

-----Original Message-----
From: Anderson, Margot
Sent: Friday, March 23, 2001 11:58 AM
To: Breed, William
Subject: FW: NPRA Recommendations on National Energy Policy

Bill,

Can you ask your crack staff if any of these policy recommendations from NPRA have merit?

'argot

-----Original Message-----
From: Kelliher, Joseph
Sent: Friday, March 23, 2001 9:04 AM
To: Anderson, Margot
Subject: NPRA Recommendations on National Energy Policy

Do any of these have merit? Many of the recs are so general is it hard to figure out exactly what the action is.

-----Original Message-----
From: Slaughter, Bob [mailto:Bob_Slaughter@npradc.org]
Sent: Thursday, March 22, 2001 3:52 PM
To: Kelliher, Joseph
Cc: Anthony, Betty; Sternfels, Urvan
Subject: NPRA Recommendations on National Energy Policy

Joe Kelliher: Attached is a short document which includes NPRA's current thinking as to what changes in national energy policy are needed to help the refining sector.

I would like specifically to highlight three:

One. We believe that the Administration is missing an important opportunity to improve energy policy by not addressing the onroad diesel sulfur rule. This rule will have a greater adverse supply impact than any other in the next five years and should be reviewed. Instead of requiring essentially 100% of onroad diesel output to be reduced from 500 ppm to 15 ppm sulfur by mid-2006, at a cost of $8 billion, the Administration could move the

6374

required supply date back to 2008-9 and provide a reduction in the diesel
excise tax for 15ppm sulfur diesel sold in advance of the 2008 date. This
could provide all the necessary supply for new trucks which need the diesel
in 2006-7 (probably only 5% of demand). There are no environmental benefits
from using the new diesel in old truck engines, so the program in its current form constitutes massive waste, since those trucks aren't a sufficient force in the market until 2008 at the earliest. This change will help prevent loss of diesel supply and refinery closures which will take place under the rule in its current form. The overall benefits of the
program are not reduced. We would like to talk with you more on this.

Two. The EPA's enforcement campaign against U.S. refineries should be halted and reexamined. As you know, it is impossible to build new refineries, so the industry has had to add capacity at existing sites in an
attempt to maintain an adequate supply of products for consumers in the past
twenty years. Even at that, the industry has been able to keep U.S. capacity only flat over the past decade, so new demand has been met by increased imports of refined products. The Browner EPA launched an extensive
and coordinated campaign against the industry, alleging that capacity additions diring the past twenty years were not appropriately permitted. This despite the fact that refinery improvements were made with the knowledge of both state and federal environmental agencies and in keeping
with permitting requirements as they were understood at that time. The EPA
has sent section 114 requests, in effect blanket subpoenas, to most refiners, and many are now facing notices of violation and legal action. A
few have settled because they believe that it is easier to pay a fine, sign
a consent decree and move forward than resist. All this comes at a time when federal and state authorities have urged the industry to continue its
herculean efforts to produce product all-out to avoid shortages. EPA's actions are really nothing more than an attempt to discredit the industry
and collect tribute in the form of fines in order to allow refiners to get
on with their business. We believe that everyone in the industry should obey the law, and we believe that they do, often under difficult circumstances. But this activity goes far beyond the pale of reasonable enforcement activity and should cease.

Three. The Unocal patents, recently upheld by a federal court of appeals in
a decision that the Supreme Court let stand, provide no real benefit to the
industry or consumers. The huge royalties granted by a California District
Court-- 5.3/4 cents/gallon--are far in excess of the cost of even the reformulated gasoline program and may well cost consumers over $200 million
per year when implemented. The existence of the payents will increase the
cost of gasoline, reduce supply, and eliminate all of the incentive for overcompliance with environmental regulations. The patent will also make it
even harder to use ethanol in gasoline where ozone problems exist during the

6375

summer months (e.g. Chicago and Milwaukee). The Administration should study
this issue and take steps to put any royalty collections on hold. Otherwise, this situation will affect Midwestern and East Coast gasoline supplies adversely this summer, as it did last year.

The rest of our thinking is attached. Thank you for your call yesterday.
I'm available to discuss these matters with you at any time.

Bob Slaughter
NPRA 202.457.0480 x 152; home] b6

<<natenergypol2.doc>>

6376

RECOMMENDATION TO ENHANCE US NUCLEAR ENERGY RD&D

The Need for Long-term R&D

The Nuclear Energy Research Advisory Committee (NERAC), formed in compliance with the Federal Advisory Committee Act (FACA), has recommended that DOE pursue nuclear energy RD&D programs to:

- revitalize U.S. nuclear energy supply,
- re-instate effective radio-isotope production for medicine and industry,
- increase basic nuclear research, and
- re-build the physical and human infrastructure needed for these purposes

Roadmap for Expanded Nuclear Power Capability

NERAC has also been charged to oversee DOE's development of a Roadmap defining:

- the goals of both a long- and short-term nuclear energy R&D program,
- the technology gaps that need to be closed to reach those goals,
- advanced nuclear power plant candidates with potential for short term (by 2020) and long term (by 2050) deployment,
- appropriate resource requirements and time frames, and
- criteria to measure progress toward the goals.

Goals for Future Nuclear Power Plants

The three primary, and their subsidiary, goals for new nuclear power plants are:

- Sustainability, providing
  - -free energy with essentially no air pollution or greenhouse gas emissions
  - a stable and abundant fuel supply
  - minimum amounts of radioactive waste
  - a reduced long-term stewardship burden
  - route to weapons proliferation.
- Improved safety and reliability, assuring
  - equal or better plant availability factors (>90%) than today
  - reduced chance of accidental fuel damage
  - need for emergency response.
- Economic competitiveness against other energy sources, including
  - a full life-cycle cost advantage
  - a comparable level of financial risk.

These criteria will allow screening down to a small number of candidates on which to place primary focus and resources. Safety, environmental, and non-proliferation goals and criteria, along with cost competitiveness, are of key importance in assuring successful deployment. Of these, NERAC has recommended that internationally accepted methods of assessment and standards for proliferation resistance should be more fully developed, building on the existing international non-proliferation regime. This need is of particular importance for development of acceptable advanced plant candidates slated for long-term deployment that recycle to maximize the use of nuclear fuel.

Industrial and International Cooperation

Two common themes in the NERAC recommendations are:

- industry and DOE, with its national labs, should enter into cost-share partnering, especially for the nuclear power plants slated for near term deployment, and
- international cooperation should be fostered to assure global development consistent with U. S. policies on safety , the environment, and proliferation resistance.

Doe has engaged U.S. industry, and those of its overseas allies with on-going nuclear energy programs, in the development of the Roadmap.

Recommendations to Strengthen Nuclear Energy RD&D

- Strengthen the NERI program to foster innovative nuclear power concepts.
- Strengthen the NEPO program, cost-shared with industry, to assure the continued effective operation of present plants
- Strengthen the university program to develop a new generation of nuclear engineers and scientists.
- Expand long-term R&D by an additional $280 million annually by 2005
- Implement the roadmap by developing a vigorous program to demonstrate the most promising of these technologies. This will require substantial additional funding and will involve a concerted interaction with industry

Re-building the Nuclear Energy Infrastructure

NERAC has advised that to achieve the goals and meet the needs outlined above will require re-building the U.S. nuclear energy infrastructure, both in human skills and facilities. Re-building is required also for national security and the long-term stewardship of defense nuclear materials and facilities as well as the effective management of radioactive wastes and spent fuels from both civilian and defense sectors. A fundamental starting point is the training of qualified personnel in our universities.

This re-building, coupled with the implementation of the RD&D programs recommended above, will entail substantial funding increases and enhanced priority within the federal government and industry, without which the nation's energy needs and national security will not be achieved.
Contact:

CS

65

AGA American Gas Association

March 1, 2001

Natural Gas Utilities
Recommendations for National Energy Policy

Overview

It is in the nation's best interest to cultivate and [redacted] that makes the most of each fuel's unique attributes and advantages. Natural gas is making a significant contribution to meeting Americans' energy needs for an affordable, reliable energy resource. In order to provide Americans an energy future that is free of oil embargoes and rolling power blackouts, we must now adopt [redacted] national energy policy that recognizes the vital [redacted] Such a policy provides the energy to ensure the prosperity of American families and businesses.

Future of Natural Gas in the United States

The United States relies on [redacted]. Natural gas burns [redacted] than any other fossil fuel, is almost [redacted]orth American and provides efficient, responsive heat and energy for consumers. Because of the many advantages that natural gas offers Americans, demand for natural gas could [redacted]percent in the [redacted] decades of the 21st century, according to projections by the Department of Energy and the American Gas Foundation -- but only if recommended policy changes are made.

Results of Greater Use of Natural Gas

The increased use of natural gas would provide numerous benefits for all Americans:

- Lower oil imports by 4.5 million barrels per day, providing **national security**.
- Provide Americans an extremely **efficient** use of energy, especially in its [redacted]ions, such as furnaces, water heaters, microturbines, desiccant dehumidifiers and combined heat and power.
- Supply needed relief to the over-burdened electric grid, along with greater **reliability** to businesses and home offices, through new technologies which generate both heat and electricity and can be sited closer to the consumer.
- Clean up the air by lowering carbon dioxide emissions by 930 million tons per year.

(Over for AGA's specific policy recommendations)

b(5)

AGA
American Gas Association

March 1, 2001

AGA's Recommendations for a National Energy Policy

Protection of low-income consumers: Expand current Low Income Home Energy Assistance Program (LIHEAP) and weatherization funding.

Expansion of natural gas infrastructure: Change the current gas depreciation schedule for natural gas utility expenses to an accelerated 7-year schedule. This will free up capital for natural gas utilities to invest in new pipelines, storage facilities and upgrading the existing infrastructure; ensuring continued reliable service for all natural gas consumers. Also increase RD&D on natural gas infrastructure reliability and safety; repeal tax on new customer connections (Contributions in Aid of Construction.

b(5) b(5)

Development of new natural gas technologies: Provide RD&D funding for new technologies to produce, deliver and use natural gas in a highly-efficient and safe manner; provide favorable tax treatment for highly efficient end-use technologies; reduce or eliminate barriers to market entry. b(5)

Increased energy efficiency: Provide funding to improve the energy efficiency of government facilities and schools; RD&D and tax incentives for highly efficient technologies; policy recognition of total energy efficiency.

Adequate supplies of natural gas: North America has abundant supplies of natural gas. More supply of natural gas means lower prices for consumers. AGA supports the recommendations by natural gas producers for expanded access to federal lands for exploration and production; tax provisions to stimulate domestic production; simplified agency review and permitting process.

\- AGA -

American Gas Association (202) 824-7000
400 N. Capitol St., N.W., Suite 400, Washington, D.C. 20001

6535

American Gas Association

Federal Energy Legislation
Comparison of AGA Recommended Provisions
And Provisions Contained in Senator Murkowski's
National Energy Security Act of 2001 (S. 389)

Summary: **The bill introduced by Senator Murkowski contains almost every provision recommended by AGA. It would:**

- **Encourage increased production of natural gas**
- **Allow seven-year depreciation of all new natural gas distribution, transmission, and storage facilities (representing potential tax savings to AGA gas distribution members of approximately $8 billion over ten years)**
- **Repeal CIAC and PUHCA** b(5)
- **Remove barriers to infrastructure expansion**
- **Create incentives for distributed generation and**
- **Increase LIHEAP authorizations.**

b(5)

On November 30, 2000, the Government Relations Policy Committee and the Executive Committee of the Board of Directors created the AGA Energy Legislative Steering Committee under the leadership of Dick Reiten of NW Natural. During the months of December and January, the steering committee worked closely with AGA Staff to craft a set of core principles essential to any legislation as well as specific legislative proposals embodying the advocacy priorities of AGA member companies. The result of these efforts was circulated on January 16, 2001, and was approved by the GRPC and the AGA Board of Directors on February 26, 2001. AGA Staff has also been working with other associations and Congressional Staff to ensure that these principles and proposals are incorporated in the comprehensive, bipartisan legislation that will soon be a topic of Congressional attention.

On February 26, 2001, Senator Frank Murkowski, Chairman of the Senate Energy and Natural Resources Committee, introduced the National Energy Security Act of 2001 (S. 389.). This bill addresses a broad spectrum of energy issues and incorporates most of the principles and proposals that AGA has advocated throughout this effort. This memorandum highlights the natural gas provisions of interest to AGA members in the bill as well as some of the other more important energy issues it addresses.

Although much effort has already been invested, introduction of the Murkowski bill is only the starting point in the legislative process. AGA Staff will work closely with Senator Murkowski, his staff, other Senators, Members of the House of Representatives, and the Bush Administration in the weeks ahead to advance the AGA legislative proposals approved by the GRPC.

Following is a brief summary of what is included in the bill, organized to follow the order of the legislative proposals as recommended and ultimately approved by the AGA Legislative Steering Committee and GRPC.

Federal E&P Studies
The bill calls for reports on all federal actions affecting energy supply or delivery and annual reports on progress toward energy independence, which would be produced by DOE rather than the National Academy of Sciences. (Sections 101, 102.)

Renewal and Expansion of Infrastructure
Senator Murkowski has decided not to mandate a White House Office of National Energy Policy in light of President Bush's creation of a Cabinet-level "National Energy Policy Development Group" led by Vice President Cheney. The staff director of this group is Andrew Lundquist, until recently the staff director of the Senate Energy and Natural Resources Committee. However, codifying such an effort in the Executive Office of the President is still desirable.

The bill requires federal studies of rights of way over federal lands to determine which of these can support additional energy infrastructure. (Section 104.)

It requires FERC and other pertinent agencies to review the pipeline certification process to determine where time and cost can be saved. (Section 109.)

The bill requires DOE, FERC and other agencies having a role in the pipeline certification process to enter into an interagency agreement regarding environmental review of interstate pipeline certificate applications with deadlines for completion of required review. (Section 113.)

It requires DOT to implement an accelerated cooperative program of R&D regarding pipeline safety. (Section 114.)

The bill contains several significant tax incentives to expand infrastructure that are described under Tax Provisions in this memorandum.

Equitable Energy Efficiency Regulations
The bill does not address the need to give fair and equitable treatment to natural gas in energy-efficiency standards and related administrative proceedings before DOE and other federal agencies. AGA expects to continue to pursue this issue as this bill and others move forward through Congress.

b(5) -

LIHEAP
The bill increases LIHEAP authorization to $3 billion annually for the years 2000-2010 and $1 billion in emergency funds annually. It does not call for indexing authorizations to rising costs. (Section 601.)

Building Efficiency
The bill extends authority regarding federal energy-savings performance contracts. (Section 605.)

The bill creates in DOE an energy-efficient schools program, with authorizations in excess of $200 million. (Section 602.)

6537

b(5)

Tax Provisions

The bill provides for seven-year tax depreciation for new natural gas pipe, storage facilities, equipment and appurtenances. (Section 921.) It also allows the expensing of storage facilities. (Section 922.)

It provides for a tax credit for distributed power facilities used in nonresidential real or rental residential property used in trade or business (in excess of 1 kW) and used in manufacturing or plant activities (in excess of 500 kW). A credit is also extended to combined heat and power systems. (Section 971.)

The bill provides for the repeal of the tax on contributions in aid of construction (CIAC). (Section 959.)

The bill provides tax incentives for NGVs and other alternative-fuel vehicles. (Sections 981-985.)

New Natural Gas Technologies

DOE is required to conduct a five-year RD&D program to increase the reliability, efficiency, safety, and integrity of the natural gas delivery infrastructure and for distributed energy resources with such funds authorized as are necessary. (Section 115.)

Each federal agency is required to carry out periodic review of its regulations to ensure that they do not inhibit market entry of new energy-efficient technologies. (Section 112.)

Production Incentives

- Tax credit for nonconventional fuels (Section 29)
- Expensing geological and geophysical costs and shut-in royalties
- Tax credits for marginal oil and gas wells
- Royalty relief when the Henry Hub price is less than $2.30 per MMBtu
- Deepwater royalty relief

Other significant gas-related provisions included in the Murkowski bill include:

- PUHCA repeal
- Improvements to federal oil and gas leasing management, including the ability of states to assume responsibility for leasing on federal lands
- ANWR leasing program
- FERC jurisdiction over wholesale electric reliability
- Prospective PURPA repeal
- Tax credits for energy-efficient appliances and homes

A copy of the complete bill can be downloaded at:
http://thomas.loc.gov/cgi-bin/query/z?c107:S.389: or at http://energy.senate.gov

AGA Contacts: Darrell Henry 202-824-7219, dhenry@aga.org (Advocacy)
Jeff Petrash 202-824-7231, jpetrash@aga.org (Legislation

The White House

Office of the Press Secretary

For Immediate Release September 27, 1993

Fact Sheet
Nonproliferation And Export Control Policy

The President today established a framework for U.S. efforts to prevent the proliferation of weapons of mass destruction and the missiles that deliver them. He outlined three major principles to guide our nonproliferation and export control policy:

- Our national security requires us to accord higher priority to nonproliferation, and to make it an integral element of our relations with other countries.

- To strengthen U.S. economic growth, democratization abroad and international stability, we actively seek expanded trade and technology exchange with nations, including former adversaries, that abide by global nonproliferation norms.

- We need to build a new consensus - embracing the Executive and Legislative branches, industry and public, and friends abroad - to promote effective nonproliferation efforts and integrate our nonproliferation and economic goals.

The President reaffirmed U.S. support for a strong, effective nonproliferation regime that enjoys broad multilateral support and employs all of the means at our disposal to advance our objectives.

Key elements of the policy follow.

Fissile Material

The U.S. will undertake a comprehensive approach to the growing accumulation of fissile material from dismantled nuclear weapons and within civil nuclear programs. Under this approach, the U.S. will:

- Seek to eliminate where possible the accumulation of stockpiles of highly-enriched uranium or plutonium, and to ensure that where these materials already exist they are subject to the highest standards of safety, security, and international accountability.

- Propose a multilateral convention prohibiting the production of highly-enriched uranium or plutonium for nuclear explosives purposes or outside of international safeguards.

- Encourage more restrictive regional arrangements to constrain fissile material production in regions of instability and high proliferation risk.

- Submit U.S. fissile material no longer needed for our deterrent to inspection by the International Atomic Energy Agency.

- Pursue the purchase of highly-enriched uranium from the former Soviet Union and other countries and its conversion to peaceful use as reactor fuel.

- Explore means to limit the stockpiling of plutonium from civil nuclear programs, and seek to minimize the civil use of highly-enriched uranium.

- Initiate a comprehensive review of long-term options for plutonium disposition, taking into account technical, nonproliferation, environmental, budgetary and economic considerations. Russia and other nations with relevant interests and experience will be invited to participate in this study.

The United States does not encourage the civil use of plutonium and, accordingly, does not itself engage in plutonium reprocessing for either nuclear power or nuclear explosive purposes. The United States, however, will maintain its existing commitments regarding the use of plutonium in civil nuclear programs in Western Europe and Japan.

Export Controls

To be truly effective, export controls should be applied uniformly by all suppliers. The United States will harmonize domestic and multilateral controls to the greatest extent possible. At the same time, the need to lead the International policy interests may justify unilateral export controls in specific cases. We will review our unilateral dual-use export controls and policies, and eliminate them unless such controls are essential to national security and foreign policy interests.

We will streamline the implementation of U.S. nonproliferation export controls. Our system must be more responsive and efficient, and not inhibit legitimate exports that play a key role in American economic strength while preventing exports that would make a material contribution to the proliferation of weapons of mass destruction and the missiles that deliver them.

Nuclear Proliferation

The U.S. will make every effort to secure the indefinite extension of the Non-Proliferation Treaty in 1995. We will seek to ensure that the International Atomic Energy Agency has the resources needed to implement its vital safeguards responsibilities, and will work to strengthen the Iaea's ability to detect clandestine nuclear activities.

Missile Proliferation

We will maintain our strong support for the Missile Technology Control Regime. We will promote the principles of the Mtcr Guidelines as a global missile nonproliferation norm and seek to use the Mtcr as a mechanism for taking joint action to combat missile proliferation. We will support prudent expansion of the Mtcr's membership to include additional countries that subscribe to international nonproliferation standards, enforce effective export controls and abandon offensive ballistic missile programs. The United States will also promote regional efforts to reduce the demand for missile capabilities.

The United States will continue to oppose missile programs of proliferation concern, and will exercise particular restraint in missile-related cooperation. We will continue to retain a strong presumption of denial against exports to any country of complete space launch vehicles or major components.

The United States will not support the development or acquisition of space-launch vehicles in countries outside the Mtcr.

For Mtcr member countries, we will not encourage new space launch vehicle programs, which raise questions on both nonproliferation and economic viability grounds. The United States will, however, consider exports of Mtcr-controlled items to Mtcr member countries for peaceful space launch programs on a case-by-case basis. We will review whether additional constraints or safeguards could reduce the risk of misuse of space launch technology. We will seek adoption by all Mtcr partners of policies as vigilant as our own.

Chemical and Biological Weapons

To help deter violations of the Biological Weapons Convention, we will promote new measures to provide increased transparency of activities and facilities that could have biological weapons applications. We call on all nations -- including our own -- to ratify the Chemical Weapons Convention quickly so that it may enter into force by January 13, 1995. We will work with others to support the international Organization for the Prohibition of Chemical Weapons created by the Convention.

Regional Nonproliferation Initiatives

Nonproliferation will receive greater priority in our diplomacy, and will be taken into account in our relations with countries around the world. We will make special efforts to address the proliferation threat in regions of tension such as the Korean peninsula, the Middle East and South Asia, including efforts to address the underlying motivations for weapons acquisition and to promote regional confidence-building steps.

In Korea, our goal remains a non-nuclear peninsula. We will make every effort to secure North Korea's full compliance with its nonproliferation commitments and effective implementation of the North-South denuclearization agreement.

In parallel with our efforts to obtain a secure, just, and lasting peace in the Middle East, we will promote dialogue and confidence-building steps to create the basis for a Middle East free of weapons of mass destruction. In the Persian Gulf, we will work with other suppliers to contain Iran's nuclear, missile, and Cbw ambitions, while preventing reconstruction of Iraq's activities in these areas. In South Asia, we will encourage India and Pakistan to proceed with multilateral discussions of nonproliferation and security issues, with the goal of capping and eventually rolling back their nuclear and missile capabilities.

In developing our overall approach to Latin America and South Africa, we will take account of the significant nonproliferation progress made in these regions in recent years. We will intensify efforts to ensure that the former Soviet Union, Eastern Europe and China do not contribute to the spread of weapons of mass destruction and missiles.

Military Planning and Doctrine

We will give proliferation a higher profile in our intelligence collection and analysis and defense planning, and ensure that our own force structure and military planning address the potential threat from weapons of mass destruction and missiles around the world.

Conventional Arms Transfers

We will actively seek greater transparency in the area of conventional arms transfers and promote regional confidence- building measures to encourage restraint on such transfers to regions of instability. The U.S. will undertake a comprehensive review of conventional arms transfer policy, taking into account national security, arms control, trade, budgetary and economic competitiveness considerations.

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The White House

Office of the Press Secretary

For Immediate Release September 27, 1993

Fact Sheet
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- We need to build a new consensus - embracing the Executive and Legislative branches, industry and public, and friends abroad - to promote effective nonproliferation efforts and integrate our nonproliferation and economic goals.

The President reaffirmed U.S. support for a strong, effective nonproliferation regime that enjoys broad multilateral support and employs all of the means at our disposal to advance our objectives.

Key elements of the policy follow.

Fissile Material

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- Seek to eliminate where possible the accumulation of stockpiles of highly-enriched uranium or plutonium, and to ensure that where these materials already exist they are subject to the highest standards of safety, security, and international accountability.

- Propose a multilateral convention prohibiting the production of highly-enriched uranium or plutonium for nuclear explosives purposes or outside of international safeguards.

- Encourage more restrictive regional arrangements to constrain fissile material production in regions of instability and high proliferation risk.

- Submit U.S. fissile material no longer needed for our deterrent to inspection by the International Atomic Energy Agency.

Williams, Ronald L

From: Cook, Trevor
Sent: Wednesday, March 07, 2001 9:44 AM
To: Anderson, Margot
Subject: RE: template

I have a meeting on Friday at 2:00pm so sometime before then is good for me.

Trev.

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, March 06, 2001 6:27 PM
To: Haspel, Abe; Zimmerman, MaryBeth; Lockwood, Andrea; Breed, Patricia; Breed, William; KYDES, ANDY; Whatley, Michael; Carter, Douglas; Braitsch, Jay; Melchert, Elena; Cook, Trevor; 'jkstier@bpa.gov'
Cc: Kelliher, Joseph
Subject: RE: template

All,

(b)(5)

Who can meet on Friday afternoon?

Margot

<< File: NEP Policy Issues.doc >> << File: template for policy ideas.doc >>

-----Original Message-----
From: Anderson, Margot
Sent: Tuesday, March 06, 2001 9:33 AM
To: Conti, John; Haspel, Abe; Zimmerman, MaryBeth; Lockwood, Andrea; Breed, Patricia; Breed, William; KYDES, ANDY; Whatley, Michael; Carter, Douglas; Braitsch, Jay; Melchert, Elena; Cook, Trevor; 'jkstier@bpa.gov'
Cc: Kelliher, Joseph
Subject: RE: template

All,

I discussed with Kelliher and received comments from PO and EE. Anyone else going to weigh in before I finalize and set some deadlines?

Margot

-----Original Message-----

7820

From: Anderson, Margot
Sent: Monday, March 05, 2001 4:56 PM
To: Conti, John; Haspel, Abe; Zimmerman, MaryBeth; Lockwood, Andrea; Breed, Patricia; Breed, William; KYDES, ANDY; Whatley, Michael; Carter, Douglas; Braitsch, Jay; Melchert, Elena; Cook, Trevor; 'jkstier@bpa.gov'
Cc: Kelliher, Joseph
Subject: template

<< File: template for policy ideas.doc >>

All,

Comments, please.

Margot

7821

Martin, Adrienne

WH

155

From:	Anderson, Margot
Sent:	Tuesday, April 03, 2001 3:36 PM
To:	'Charles Smith (E-mail)'
Subject:	FW: NA Transmission Line Maps

NAtranslines_bw.doc NAtranslines_color.doc

Charlie,

(b)(5)

Margot

-----Original Message-----
From: Terry, Tracy
Sent: Tuesday, April 03, 2001 9:17 AM
To: Anderson, Margot
Cc: Conti, John
Subject: FW: NA Transmission Line Maps

Margot - Here are the transmission line maps. Let me know if these are OK or if we need something else.

-----Original Message-----
From: Forbes, Leslie [mailto:LForbes@ftenergy.com]
Sent: Friday, March 30, 2001 4:46 PM
To: Terry, Tracy
Subject: NA Transmission Line Maps

March 30, 2001

Dear DOE:

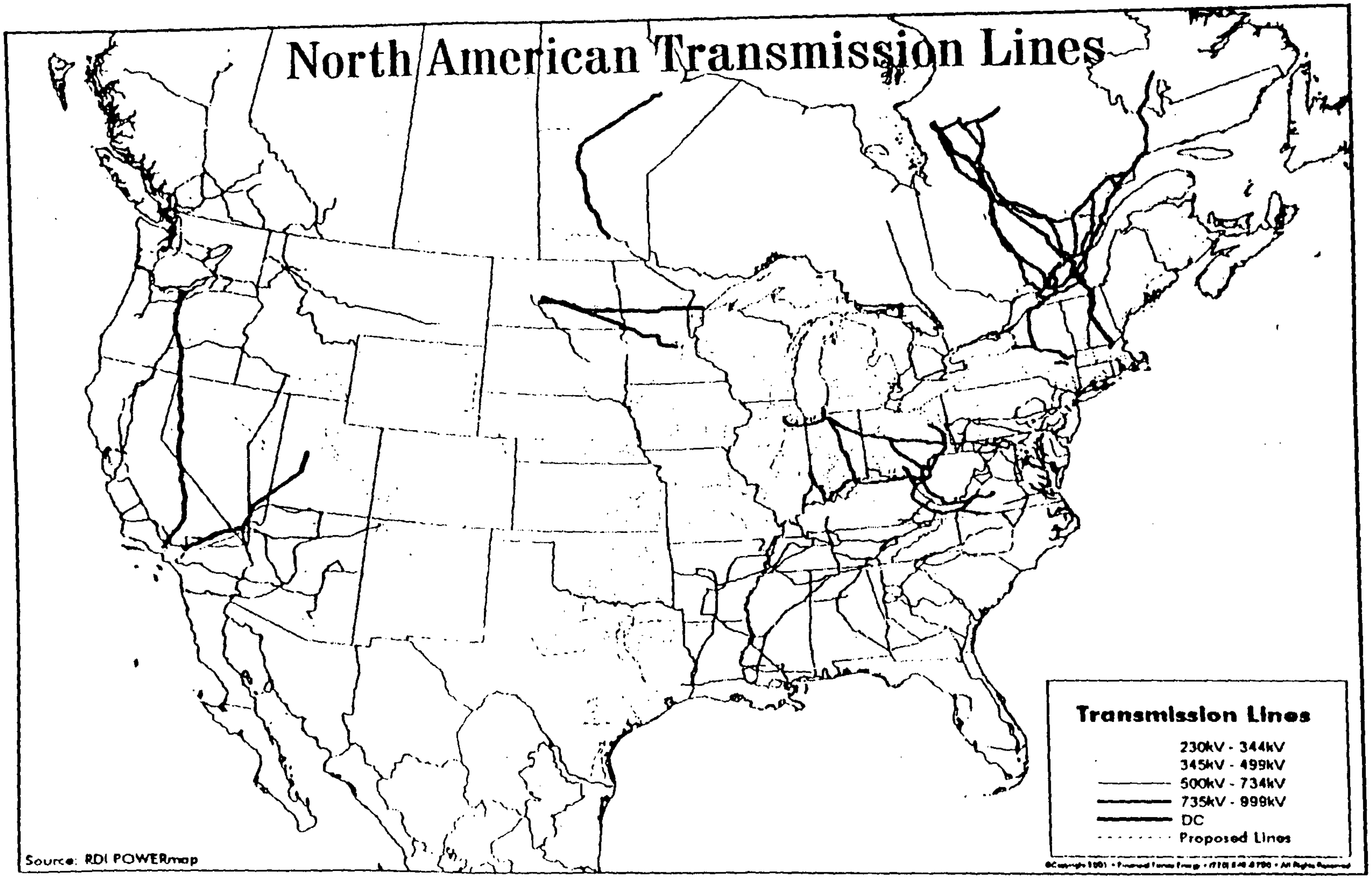
Here are the map images you requested. If you need additional information please let us know.

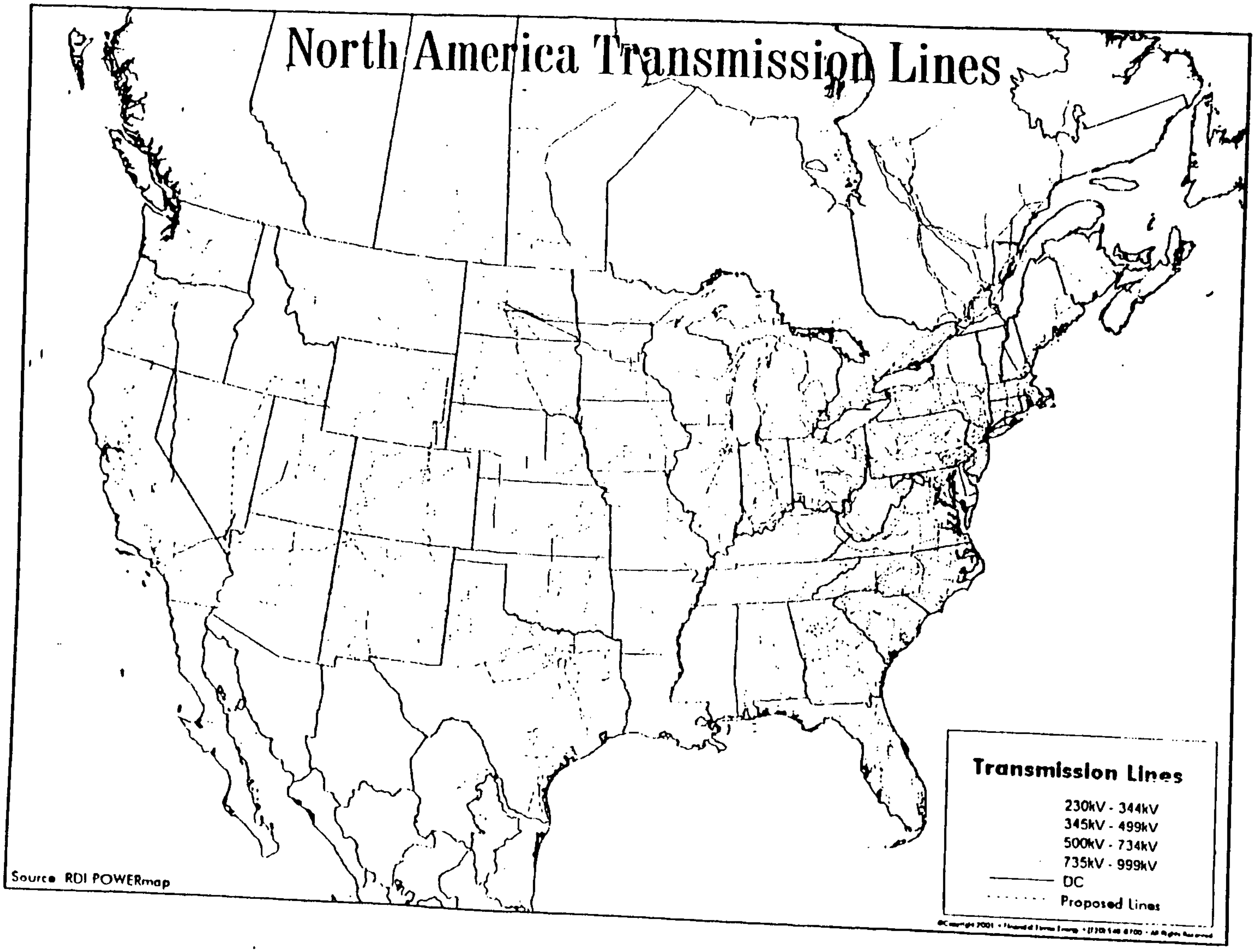
<<NAtranslines_bw.doc>> <<NAtranslines_color.doc>>
Thank you,

Leslie Forbes

Leslie Forbes
GIS Cartographer
Financial Times Energy
720-548-5472

8181


North American Transmission Lines
Transmission Lines
230kV - 344kV
345kV - 499kV
500kV - 734kV
735kV - 999kV
DC
Proposed Lines
Source: RDI POWERmap


North America Transmission Lines
Transmission Lines
230kV - 344kV
345kV - 499kV
500kV - 734kV
735kV - 999kV
DC
Proposed Lines
Source RDI POWERmap

8183

Kelliher, Joseph

From: Kelliher, Joseph
Sent: Tuesday, July 03, 2001 9:30 AM
To: 'Dave Nevius'
Subject: RE: "Energy Legislative Agenda"

There was a reference to the NEP recommendation that DOE develop legislation that would "enhance reliability," among other goals.

-----Original Message-----
From: Dave Nevius [mailto:Dave.Nevius@nerc.net]
Sent: Tuesday, July 03, 2001 9:21 AM
To: Kelliher, Joseph
Cc: Linda Stuntz (E-mail); DNC (E-mail)
Subject: "Energy Legislative Agenda"

Joe
Press accounts say the White House sent an "Energy Legislative Agenda" to the Hill last Thursday. What did this agenda say about reliability legislation?
Thanks.
dave

PS - I may not have anything to you on ideas for how to approach a "national grid study" until early next week. We had to do a little scrambling to respond to Mr. DeLay's request to address a draft electricity restructuring bill, as well as a couple of other crash items. FYI, the Reliability Legislation Coalition is meeting today (July 3, 1-4 pm in CEA offices) to discuss what can be done to bring others on board in support of the consensus reliability legislation that is already supported by 14 industry and state organizations. You're welcome to attend.

8950

DOE015-2293

Kelliher, Joseph

From: Kelliher, Joseph
Sent: Wednesday, June 20, 2001 5:01 PM
To: Glotfelty, Jimmy
Subject: FW: NEPDG Long-Term Strategy Meeting - 4:45 TOMORROW

You should go to the meetnig and reception. What is your SS and DOB?

-----Original Message-----
From: Kjersten_S._Drager@ovp.eop.gov%internet
[mailto:Kjersten_S._Drager@ovp.eop.gov]
Sent: Wednesday, June 20, 2001 4:48 PM
To: Reed, Craig; Kelliher, Joseph;
sue_ellen_wooldridge@ios.doi.gov%internet; gibson.tom@epa.gov%internet
Daigle.stephanie@epa.gov%internet; Dina.ellis@do.treas.gov%internet;
kmurphy@osec.doc.gov%internet; Michelle.poche@ost.dot.gov%internet;
Patricia.stahlschmidt@fema.gov%internet; scott.douglas@fema.gov%internet
Cc: Andrew_D._Lundquist@ovp.eop.gov%internet;
Karen_Y._Knutson@ovp.eop.gov%internet; John_Fenzel@ovp.eop.gov%internet;
Megan_E._McGinn@ovp.eop.gov%internet
Subject: NEPDG Long-Term Strategy Meeting - 4:45 TOMORROW

Andrew Lundquist and Karen Knutson, Director and Deputy Director, respectively, of the National Energy Policy Development Group, have asked
that everyone on this list attend a pre-meeting tomorrow, Thursday, June 21, at 4:45 p.m. in the Vice President's Ceremonial Office, 276 OEOB, to discuss long-term strategy with regard to the National Energy Policy.

Following the meeting in the Ceremonial Office, Andrew and Karen are hosting a reception beginning at 5:30 p.m. just down the hall out on Mrs.
Cheney's balcony, room 200 OEOB. You are all invited. The reception is being held in appreciation for all of the hard work that went into the production of the 2001 National Energy Policy report by NEPDG agency and White House staff. Since some of you are new "liaisons" for your respective agencies, this will be a good way for you to meet the people you
will be working with on the implementation of the Plan. There will be snacks and plenty of beverages.

Please confirm with me whether or not you'll be able to make the 4:45 tomorrow. If you'll be attending, I'll need your social security # and date of birth in order to clear you into the building. If you have already e-mailed me your info., no need to do so again. Otherwise, please
send me your info. as soon as possible.

Thanks. - Kjersten Drager, Assistant to the Director, NEPDG

8956

Table 10.1 Renewable Energy Consumption by Source, 1989-1999

(Quadrillion Btu)

Year	Wood and Waste [1]	Geothermal [2]	Conventional Hydroelectric Power [3,4]	Solar [5]	Wind [6]	Total
1989	R3.050	R0.338	R2.999	R0.059	R0.024	R6.470
1990	R2.665	R0.359	R3.140	0.063	R0.032	R6.260
1991	R2.679	R0.368	R3.222	0.066	R0.032	R6.367
1992	R2.826	0.379	2.863	0.068	0.030	R6.167
1993	R2.782	0.393	3.147	0.071	0.031	R6.424
1994	R2.914	0.395	2.971	0.072	0.036	R6.387
1995	R3.044	0.339	3.474	0.073	0.033	R6.963
1996	R3.104	0.352	R3.915	0.075	0.035	R7.482
1997	R2.982	R0.328	R3.940	0.074	R0.034	R7.358
1998	R2.991	R0.335	R3.552	0.074	R0.031	R6.984
1999E	3.514	0.327	3.417	0.076	0.038	7.373

[1] Wood, wood waste, black liquor, red liquor, spent sulfite liquor, pitch, wood sludge, peat, railroad ties, utility poles, municipal solid waste, landfill gas, methane, digester gas, liquid acetonitrile waste, tall oil, waste alcohol, medical waste, paper pellets, sludge waste, solid byproducts, tires, agricultural byproducts, closed looped biomass, fish oil, and straw.

[2] Includes electricity imports from Mexico that are derived from geothermal energy. Includes grid-connected electricity, and geothermal heat pump and direct use energy. Excludes shaft power and remote electrical power.

[3] Hydroelectricity generated by pumped storage is not included in renewable energy.

[4] Includes electricity net imports from Canada that are derived from hydroelectric power.

[5] Includes solar thermal and photovoltaic energy.

[6] Includes only grid-connected electricity.

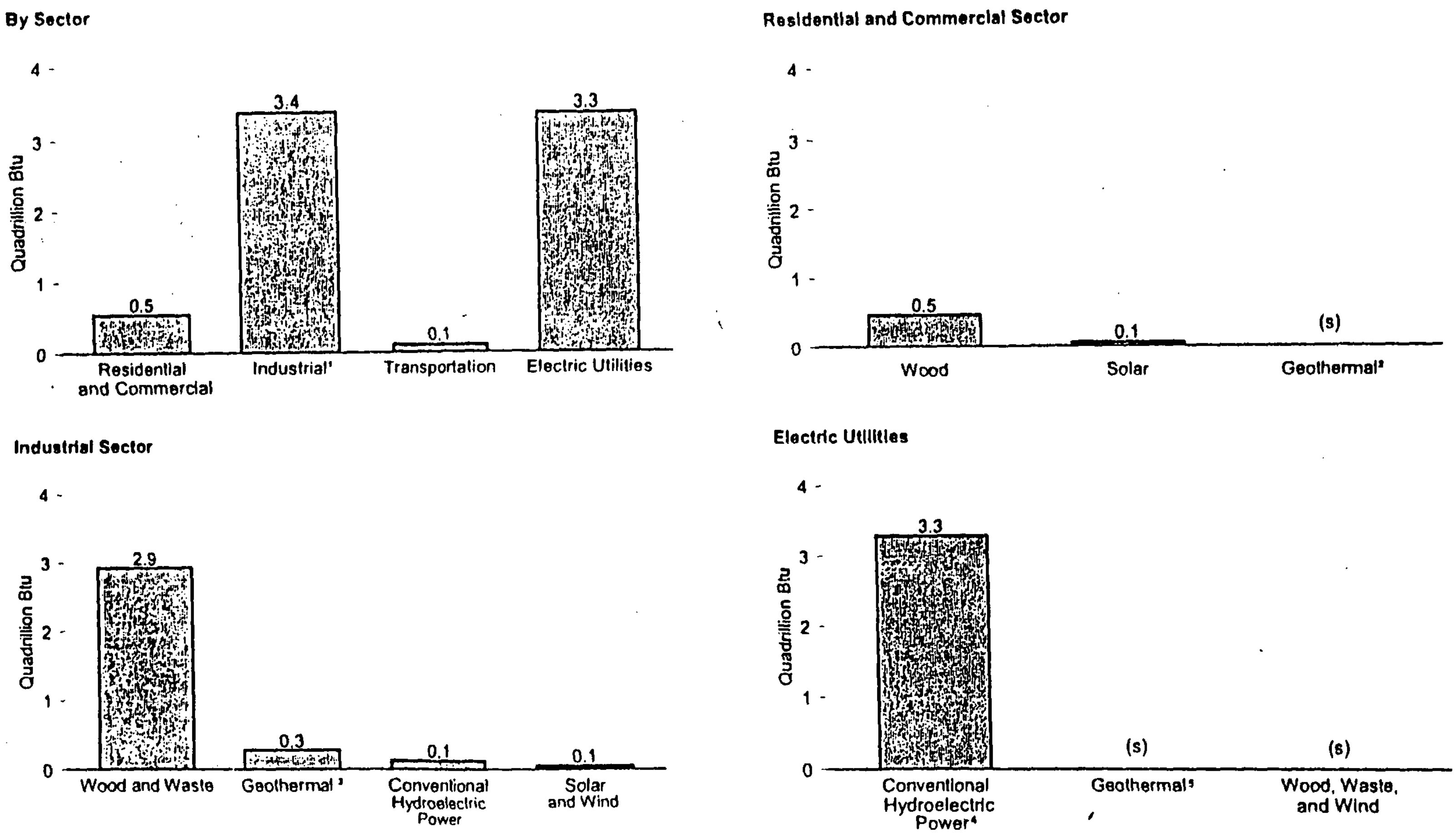
R=Revised. E=Estimated.

Note: Totals may not equal sum of components due to independent rounding.

Web Page: http://www.eia.doe.gov/fuelrenewable.html.

Sources: • 1989—Energy Information Administration (EIA) estimates. • 1990-1993—EIA, *Renewable Energy Annual*, annual reports. • 1994-1998—EIA, *Renewable Energy Annual 1999* (December 1999). • 1999—EIA estimates.

Figure 10.2 Renewable Energy Consumption by Sector, 1999



[1] Generation of electricity by nonutility power producers is included in the industrial sector, not the electric utility sector. Covers facilities of 1 megawatt or greater capacity.
[2] Geothermal heat pump and direct energy use.
[3] Geothermal electricity generation, heat pump, and direct energy use.
[4] Includes electricity net imports from Canada that are derived from hydroelectric power.
[5] Includes electricity imports from Mexico that are derived from geothermal energy.
(s) = Less than 0.05 quadrillion Btu.
Source: Table 10.2.

0963

Table 10.2 Renewable Energy Consumption by Sector, 1989-1999
(Quadrillion Btu)

	Residential and Commercial				Industrial [1]						Transportation	Electric Utilities [2]					
Year	Wood [3]	Geothermal [4]	Solar [5]	Total	Wood and Waste [6]	Geothermal [7]	Conventional Hydroelectric Power [8]	Solar	Wind	Total	Alcohol Fuels [9]	Wood and Waste [6]	Geothermal [10]	Conventional Hydroelectric Power [8,11]	Solar and Wind	Total	Total
1989	R0 952	0.008	0.053	R1.012	R2.007	R0.122	R0.091	R0.007	R0 024	R2.250	0.071	0.020	0.208	2.908	(s)	3.137	R6.470
1990	R0.618	0.008	0.056	R0.682	R1.944	R0.159	R0.101	0.007	R0.032	R2.242	0.082	R0.022	0.192	[illegible]	(s)	3.253	R6.260
1991	R0 652	0.009	0.058	R0.719	R1.940	R0.174	R0.100	0 008	R0.032	R2.254	0.065	0.021	0.185	3.123	(s)	R3.330	R6.367
1992	R0 687	0.010	0.060	R0 756	R2.040	0.182	0.098	0.008	0.030	R2.357	R0.078	0.022	0.188	2.766	(s)	R2.976	R6.167
1993	0.592	0.010	0.062	0.664	R2.082	0.206	0 119	0.009	0.031	R2.447	0.088	R0.021	0.177	3.028	(s)	3.225	R6.424
1994	0.582	0.010	0.064	0.656	R2.214	0.214	0.136	0.009	0.036	R2.610	0.097	R0.021	0.170	2.834	(s)	3.024	R6.387
1995	0.641	0.011	0.065	0.717	R2.281	0.210	0.152	0.008	0.033	R2.685	0.104	0.017	0.118	3.322	(s)	3.467	R6.963
1996	0 644	0.012	0.066	0.722	R2.386	0.217	0.171	0.009	0.035	R2.798	0.074	0.020	0.123	R[illegible]	(s)	R3.888	R7.482
1997	R0.480	0.013	0.065	R0.558	R2.385	R0.200	0.185	0.009	R0.034	2.813	0.097	R0.021	0.115	R3.754	(s)	R3.890	R7.358
1998	R0 424	0.015	0.065	R0.503	R2.441	R0.211	R0.151	R0.0090.	R 031	R2.844	0.105	R0 021	R0.110	R3.401	(s)	R3.5328.	R 984
1999E	0.461	0.015	0.063	0.539	2.922	0.276	0.125	0.013	0.038	3.373	0.112	0.020	0.038	3.292	(s)	3.349	7.373

[1] Nonutility power producers' use of renewable energy to produce electricity and useful thermal output is included in the industrial sector, not the electric utility sector. Covers facilities of 1 megawatt or greater capacity.

[2] For Btu conversion rates, see Appendix Table A6.

[3] Wood.

[4] Geothermal heat pump and direct use energy.

[5] The solar thermal component of 0.06 quadrillion Btu for residential and commercial use is calculated by presuming an overall efficiency of 50 percent for all three categories of solar thermal collectors (low temperature, medium temperature, and high temperature), a 1,500-Btu per square foot average daily insolation, and the potential thermal energy production from the 219 million square feet of solar thermal collectors produced between 1980 and 1999. This is a simplified approach since low-temperature and high-temperature collectors have been rated at more than 50 percent efficient and medium-temperature collectors are generally less than 50 percent efficient. Included also is a very small amount of photovoltaic solar energy.

[6] Wood, wood waste, black liquor, red liquor, spent sulfite liquor, pitch, wood sludge, peat, railroad ties, utility poles, municipal solid waste, landfill gas, methane, digester gas, liquid acetonitrile waste, tall oil, waste alcohol, medical waste, paper pellets, sludge waste, solid byproducts, tires, agricultural byproducts, closed looped biomass, fish oil, and straw.

[7] Geothermal electricity generation, heat pump, and direct use energy.

[8] Hydroelectricity generated by pumped storage is not included in renewable energy.

[9] Ethanol blended into motor gasoline.

[10] Includes electricity imports from Mexico that are derived from geothermal energy.

[11] Includes electricity net imports from Canada that are derived from hydroelectric power.

R=Revised. E=Estimated. (s)=Less than 0.0005 quadrillion Btu.

Note: Totals may not equal sum of components due to independent rounding.

Web Page: http://www.eia.doe.gov/fuelrenewable.html.

Sources: • 1989—Energy Information Administration (EIA) estimates. • 1990-1993—EIA, *Renewable Energy Annual*, annual reports. • 1994-1998—EIA, *Renewable Energy Annual 1999* (December 1999). • 1999—EIA estimates.

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Table 1: Coal Production by State, 1989, 1994-1998 (Thousand Short Tons)

Coal-Producing State and Region	1998	1997	1996	1995	1994	1989	Percent Change 1997-1998	Average Annual Percent Change 1994-1998	Average Annual Percent Change 1989-1998
Alabama	23,013	24,468	24,637	24,640	23,266	27,992	-5.9	-0.3	-2.1
Alaska	1,344	1,450	1,481	1,698	1,567	1,582	-7.3	-3.8	-1.8
Arizona	11,315	11,723	10,442	11,947	13,056	11,935	-3.5	-3.5	-.6
Arkansas	24	18	21	29	51	70	32.3	-16.8	-11.0
California	-	-	-	-	-	41	-	-	-
Colorado	29,631	27,449	24,886	25,710	25,304	17,123	7.9	4.0	6.3
Illinois	39,732	41,159	46,656	48,180	52,797	59,267	-3.5	-6.9	-4.3
Indiana	36,803	35,497	29,670	26,007	30,927	33,641	3.7	4.4	1.0
Iowa	-	-	-	-	46	430	-	-	-
Kansas	341	360	232	285	284	856	-5.3	4.6	-9.7
Kentucky Total	150,295	155,853	152,425	153,739	161,642	167,389	-3.6	-1.8	-1.2
Eastern	116,654	120,918	116,951	118,541	124,447	125,739	-3.5	-1.6	-.8
Western	33,641	34,936	35,474	35,198	37,195	41,649	-3.7	-2.5	-2.3
Louisiana	3,216	3,545	3,221	3,719	3,463	2,983	-9.3	-1.8	.8
Maryland	4,060	4,160	4,093	3,667	3,632	3,376	-2.4	2.8	2.1
Missouri	372	401	710	548	838	3,378	-7.2	-18.4	-21.7
Montana	42,840	41,005	37,891	39,451	41,640	37,742	4.5	.7	1.4
New Mexico	28,597	27,025	24,067	26,813	28,041	23,702	5.8	.5	2.1
North Dakota	29,912	29,580	29,861	30,112	32,286	29,566	1.1	-1.9	.1
Ohio	28,048	29,154	28,572	26,118	29,897	33,689	-3.8	-1.6	-2.0
Oklahoma	1,661	1,621	1,701	1,876	1,911	1,753	2.5	-3.4	-.6
Pennsylvania Total	81,036	76,198	67,942	61,576	62,237	70,596	6.3	6.8	1.5
Anthracite	5,231	4,678	4,751	4,682	4,621	3,348	11.8	3.1	5.1
Bituminous	75,805	71,520	63,190	56,893	57,616	67,248	6.0	7.1	1.3
Tennessee	2,696	3,300	3,651	3,221	2,987	6,480	-18.3	-2.5	-9.3
Texas	52,583	53,328	55,164	52,684	52,346	53,854	-1.4	.1	-.3
Utah	26,075	26,683	27,507	25,167	24,399	20,102	-2.3	1.7	2.9
Virginia	33,747	35,837	35,590	34,099	37,129	43,006	-5.8	-2.3	-2.6
Washington	4,638	4,495	4,565	4,868	4,893	5,039	3.2	-1.3	-.9
West Virginia Total	171,145	173,743	170,433	162,997	161,776	153,580	-1.5	1.4	1.2
Northern	44,618	42,802	45,910	46,114	49,316	56,018	4.2	-2.5	-2.5
Southern	126,527	130,941	124,523	116,883	112,460	97,562	-3.4	3.0	2.9
Wyoming	314,409	281,881	278,440	263,822	237,092	171,558	11.5	7.3	7.0
Appalachian Total[1]	**460,400**	**467,778**	**451,868**	**434,861**	**445,370**	**464,457**	**-1.6**	**.8**	**-.1**
Interior Total[1]	**168,374**	**170,863**	**172,848**	**168,526**	**179,858**	**197,880**	**-1.4**	**-1.6**	**-1.8**
Western Total[1]	**488,762**	**451,291**	**439,140**	**429,587**	**408,276**	**318,391**	**8.3**	**4.6**	**4.9**
East of Miss. River	**570,576**	**579,369**	**563,668**	**544,246**	**566,289**	**599,015**	**-1.5**	**.2**	**-.5**
West of Miss. River	**546,960**	**510,563**	**500,188**	**488,728**	**467,216**	**381,714**	**7.1**	**4.0**	**4.1**
U.S. Total	**1,117,535**	**1,089,932**	**1,063,856**	**1,032,974**	**1,033,504**	**980,729**	**2.5**	**2.0**	**1.5**

1/ For a definition of coal-producing regions, see Appendix C.

Notes: Coal production excludes silt, culm, refuse bank, slurry dam, and dredge operations except for Pennsylvania anthracite. Totals may not equal sum of components due to independent rounding.

Sources: Energy Information Administration, Form EIA-7A, "Coal Production Report"; State Mining Agency Coal Production Reports; and/or U.S. Department of Labor, Mine Safety and Health Administration, Form 7000-2, "Quarterly Mine Employment and Coal Production Report."

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Residential Heating Oil Prices:
What Consumers Should know

Introduction

Heating oil is a petroleum product used by many Americans to heat their homes. Historically, heating oil prices have fluctuated from year to year and month to month, generally being higher during the winter months when demand is higher. This winter, consumers are even more concerned about the potential for higher prices. To understand the reasons for these price variations, consumers need to understand how heating oil is used and how and where it is produced.

Who uses heating oil?

Of the 101.5 million households in the United States, approximately 7.7 million use heating oil. Residential space heating is the primary use for heating oil, making the demand highly seasonal. Most of the heating oil use occurs during October through March. The area of the country most reliant on heating oil is the Northeast.

Some customers try to beat rising winter prices by filling their storage tanks in the summer or early fall when the prices are likely to be lower. However, most homeowners do not have large enough storage tanks to store the full amount needed to meet winter demands. Because homeowners may have to refill their tanks as often as 4 or 5 times during the heating season, rising or spiking prices are a concern.

Where does heating oil come from?

The United States has two sources of heating oil: domestic refineries and imports from foreign countries. Refineries produce heating oil as a part of the "distillate fuel oil" product family, which includes heating oils and diesel fuel. Distillate products are shipped throughout the United States by pipelines, barges, tankers, trucks and rail cars. Most imports of distillate come from Canada, the Virgin Islands and Venezuela.

Refiners are limited in the amount of heating oil they can make to meet the demands of the winter heating season. Some winter heating oil is produced by refineries in the summer and fall months and stored for winter use. During the coldest winter months, the inventories that are built in summer and fall are used to help meet the high demand. Refiners can increase heating oil production in the winter to a modest degree, but they quickly reach a point where, to produce more heating oil, they would also have to produce more of other petroleum products which could not be sold in sufficient quantities during the winter months. On the other hand, if consumer demand is high for a seasonal product, such as gasoline, refiners may delay producing heating oil for the winter, which may lower inventories at the start of the heating season.

Heating oil is brought into oil storage terminals in an area by refiners and other suppliers. For example, heating oil may be delivered to a central distribution area, such as New York Harbor, where it is then redistributed by barge to other consuming areas, such as New England. Once heating oil is in the consuming area, it is redistributed by truck, to smaller storage tanks closer to a retail dealer's customers, or directly to residential customers.

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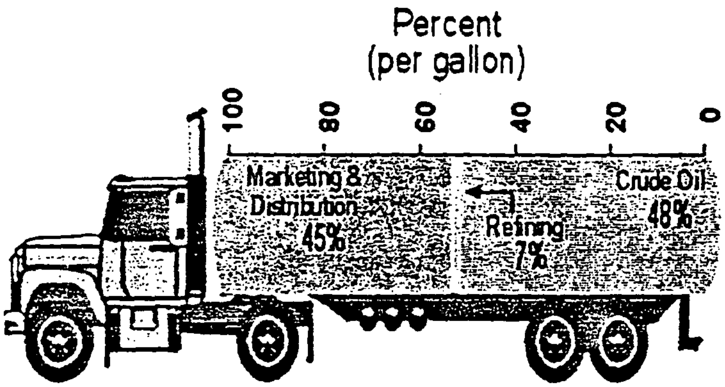
How much does a gallon of heating oil cost?

Heating oil prices paid by consumers are determined by the cost of crude oil, the cost to produce the product, the cost to market and distribute the product, as well as the profits (sometimes losses) of refiners, wholesalers and dealers. In 1999, crude oil accounted for approximately 48 percent of the cost of a gallon of heating oil. The next largest component of heating oil price (45 percent) included the cost of distribution and marketing. Lastly, refinery processing costs accounted for another 7 percent (Figure 1).

Figure 1. Heating Oil Price Components, 1999



Source: EIA's *Petroleum Marketing Annual, 1999*

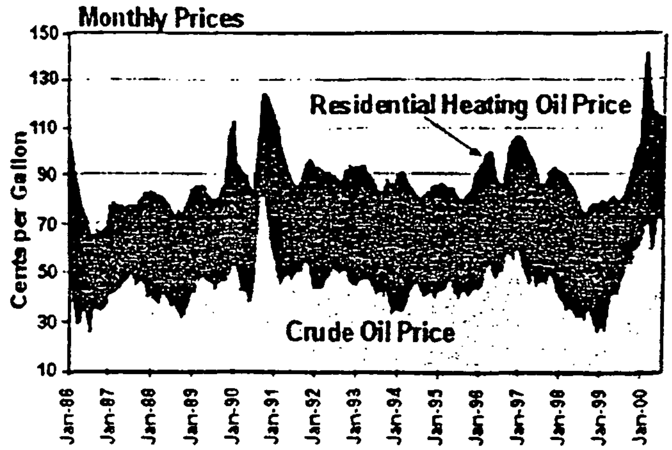
Why do heating oil prices fluctuate?

Heating oil prices paid by consumers can vary over time and by where a consumer lives. Prices can change for a variety of reasons. These include:

Seasonality in the demand for heating oil - When crude oil prices are stable, home heating oil prices tend to gradually rise in the winter months when demand is highest. However, at times, prices can surge quickly to very high levels, as occurred in January/February 2000 (see box on "What Causes a Surge in Heating Oil Prices"). A homeowner in the Northeast might use 650-1,000 gallons of heating oil during a typical winter, while consuming very little during the rest of the year.

Changes in the cost of crude oil - Since crude oil is a major price component of heating oil, changes in the price of crude oil will generally affect the price of heating oil (Figure 2). Crude oil prices are determined by worldwide supply and demand. Demand can vary worldwide with the economy and with weather. Supply can be influenced by the Organization of Petroleum Exporting Countries (OPEC) and other factors.

Figure 2. Heating Oil Prices Follow Crude Oil



Source: DRI Platt's Spot Prices, EIA *Petroleum Marketing Monthly*, 1980 - Present

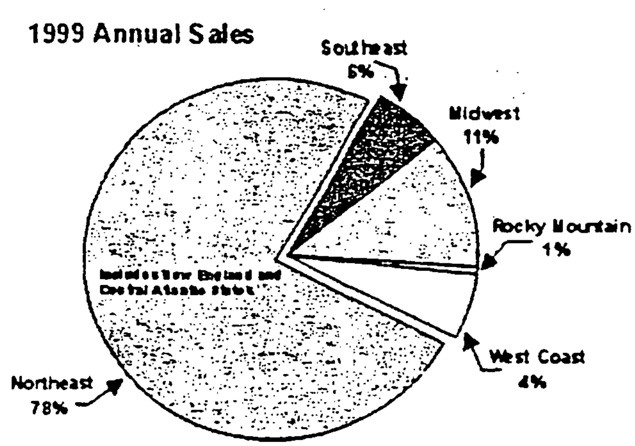
Competition in local markets - Competitive differences can be substantial between a locality with only one or a few suppliers or dealers versus an area with a large number of competitors. Consumers in remote or rural locations may face higher prices because there are fewer competitors.

Regional operating costs - Prices also are impacted by higher costs of transporting the product to locations. In addition, the cost of doing business by dealers can vary substantially depending on the area of the country in which the dealer is located. Costs of doing business include wages and salaries, benefits, equipment, lease/rent, insurance, overhead, and state and local fees.

Heating Oil is Important to Consumers in the Northeast

Of the 7.7 million households in the United States that use heating oil to heat their homes, 5.3 million households or roughly 69 percent reside in the Northeast region of the country. The Northeast region (which includes the New England and Central Atlantic States) remains the area with an appreciable share of oil-heated single family homes. In other regions, older homes have been converted from oil heat to gas heat, and oil no longer has a noticeable share of the new home construction market. Thus, the seasonal increase in inventories and demand (sales of heating oil) is largely confined to the Northeast. In 1999, 4.9 billion gallons of heating oil were sold to residential consumers in the Northeast; this is 78 percent of total U. S. residential fuel oil sales (Figure 3).

Figure 3. Residential Heating Oil Sales by Region



Source: EIA *Fuel Oil and Kerosene Sales*, 1999.
Note: Gulf Coast Sales too small to display.

What Causes a Surge in Heating Oil Prices?

Home heating oil prices sometimes can change dramatically in a short period of time. Why does this happen? If refiners, wholesalers, dealers and consumers have enough heating oil in storage and temperatures do not drop rapidly, prices hold fairly steady (assuming crude oil prices are also not changing much). However, a rapid change to colder weather can impact both supply and demand; people want more fuel at the same time that harbors and rivers are frozen or delivery systems are interrupted. During this time, the available heating oil in storage is used much faster than it can be replenished. Refineries normally cannot keep up with demand during these cold periods. Wholesale buyers become concerned that supplies are not adequate to cover short-term customer demand and bid up prices for available product. In the Northeast, for example, additional supplies may have to come from some distance away such as the Gulf Coast or Europe. It costs more to transport heating oil from these sources to the Northeast, and it also can take two to three weeks to arrive. During the time that resupply from distant markets is occurring, the supply of heating oil that sellers in the region have in storage drops further, buyers' anxiety about finding heating oil in the short term rises, and so do prices – sometimes sharply – until new supplies arrive.

Additionally, during very cold periods, prices of other heating fuels (such as natural gas or kerosene) may increase even more than heating oil. In this case, some consumers may switch from using their normal heating fuel to using heating oil, thereby increasing the demand for heating oil.

What can you do to lower your heating oil bill?

You can arrange to have your tank filled in late summer or early fall when prices are generally lower. Talk to your heating oil dealer about participating in a budget plan to help stabilize your monthly bill. You can also talk to your heating oil dealer about "cap" or fixed price protection programs, which can help keep costs down. You can obtain a home energy audit to ensure that your furnace and appliances are running efficiently before the season begins. You can achieve conservation gains by weatherizing your home, i.e., installing the proper insulation in your house and around your hot water heater. Quick and easy fixes such as caulking and weather stripping windows and doors to seal out cold air also help save energy. Installing a programmable thermostat and reducing temperature settings on your thermostat, especially when you are not at home, are other ways to reduce your heating fuel costs.

Lastly, energy assistance programs are available to heating oil customers who have a limited budget. For example, the Low Income Home Energy Assistance Program (LIHEAP) is a Federal program that distributes funds to States to help low-income households pay heating bills. Additional State energy assistance and fuel fund programs may be available to help households during a winter emergency. To find out if you qualify for assistance in your State, see:
www.acf.dhhs.gov/programs/liheap/states.htm
or contact your local heating oil dealer.

Information about heating oil prices...

For the latest update on heating oil demand, prices, and inventories, see our "Heating Oil and Propane Update" section of the web site at:

http://www.eia.doe.gov/oil_gas/petroleum/special/heating_update/heating_update.html

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Table A10: Net Generation from Gas by Census Division and State, 1999 and 1998

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Census Division and State	Industry 1999 Generation (million kWh)	Industry 1998 Generation (million kWh)	Utility 1999 Generation (million kWh)	Utility 1998 Generation (million kWh)	Nonutility 1999 Generation (million kWh)	Nonutility 1998 Generation (million kWh)
Kentucky	458	498	453	496	5	2
Mississippi	8,412	6,982	7,605	5,635	808	1,347
Tennessee	558	865	234	551	324	315
WestSouthCentral	245,198	246,804	166,899	169,222	78,299	77,582
Arkansas	4,849	5,070	3,764	3,704	1,084	1,366
Louisiana	47,731	46,004	30,163	28,318	17,568	17,686
Oklahoma	17,952	18,315	16,614	17,000	1,339	1,315
Texas	174,666	177,417	116,358	120,201	58,308	57,216
Mountain	25,144	22,528	17,198	14,788	7,946	7,741
Arizona	5,027	3,914	4,557	3,472	470	441
Colorado	5,019	3,927	2,050	964	2,969	2,963
Idaho	337	322	--	--	337	322
Montana	37	87	20	41	17	46
Nevada	9,295	8,687	6,736	6,189	2,559	2,497
New Mexico	4,235	4,542	3,304	3,631	931	910
Utah	798	674	515	463	283	211
Wyoming	397	376	16	27	381	349
PacificContiguous	**94,376**	**89,516**	**17,255**	**30,987**	**77,121**	**58,528**
California	84,177	77,652	13,918	26,385	70,258	51,266
Oregon	6,668	7,252	2,759	3,467	3,909	3,785
Washington	3,531	4,612	578	1,135	2,953	3,477
PacificNoncontiguous	4,053	3,719	2,839	2,549	1,214	1,170
Alaska	3,713	3,396	2,839	2,549	874	848
Hawaii	340	323	--	--	340	323
U.S.Total	**565,403**	**549,215**	**296,381**	**309,222**	**269,021**	**239,992**

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* = For detailed data, the absolute value is less than 0.5; for percentage calculations, the absolute value is less than 0.05 percent. kWh = Kilowatthours.

Notes: •Gas includes natural gas, waste heat, waste gas, butane, methane, propane, other gas, and digester gas. Values for the industry and nonutilities for 1999 are preliminary; utility values for 1999 are final. Values for 1998 are final. •Totals may not equal sum of components because of independent rounding. •For a given fuel type, estimated totals for nonutility data at the Census division level will not exactly equal the sum of the estimated totals for all corresponding States. This is because Census division level estimation is done by combining data regardless of State; thus avoiding the need to add State level estimates that may not all be available.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report," Form EIA-860B, "Annual Electric Generator Report-Nonutility." Form EIA-900, "Monthly Nonutility Power Plant Report."

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Table A7: Net Generation by Census Division and State, 1999 and 1998

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Census Division and State	Industry 1999 Generation (million kWh)	Industry 1998 Generation (million kWh)	Utility 1999 Generation (million kWh)	Utility 1998 Generation (million kWh)	Nonutility 1999 Generation (million kWh)	Nonutility 1998 Generation (million kWh)
Kentucky	92,633	90,936	81,658	86,150	10,974	4,786
Mississippi	35,025	34,434	32,212	31,991	2,813	2,442
Tennessee	93,444	97,730	89,683	94,142	3,761	3,588
WestSouthCentral	549,207	546,311	451,705	453,828	97,502	92,484
Arkansas	47,592	45,663	44,131	43,200	3,461	2.463
Louisiana	89,316	89,622	64,837	66,107	24,479	23,515
Oklahoma	54,849	56,189	50,279	51,453	4,570	4,737
Texas	357,450	354,837	292,458	293,068	64,992	61,769
Mountain	310,931	307,433	296,479	294,208	14,452	13,225
Arizona	83,921	82,081	83,096	81,300	825	781
Colorado	39,546	38,851	36,167	35,471	3,379	3,380
Idaho	14,454	13,849	12,456	11,978	1,998	1,871
Montana	29,263	28,461	27,597	27,618	1,666	844
Nevada	30,751	30,591	26,486	26,553	4,265	4,038
New Mexico	32,589	32,342	31,655	31,429	935	913
Utah	36,760	35,910	36,071	35,161	689	750
Wyoming	43,646	45,347	42,951	44,699	695	649
PacificContiguous	**357,550**	**341,976**	**251,646**	**258,408**	**105,905**	**83,569**
California	184,630	188,760	87,875	114,928	96,754	73,832
Oregon	56,491	51,141	51,698	46,351	4,793	4,790
Washington	116,429	102,075	112,072	97,128	4,357	4,947
PacificNoncontiguous	16,230	16,082	11,061	10,886	5,169	5,196
Alaska	5,908	5,859	4,609	4,588	1,299	1,271
Hawaii	10,322	10,223	6,452	6,298	3,870	3.926
U.S.Total	3,691,073	3,617,873	3,173,674	3,212,171	517,400	405,702

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kWh = Kilowatthours.

Notes: •Values for the industry and nonutilities for 1999 are preliminary; utility values for 1999 are final. Values for 1998 are final. •Totals may not equal sum of components because of independent rounding. •For a given fuel type, estimated totals for nonutility data at the Census division level will not exactly equal the sum of the estimated totals for all corresponding States. This is because Census division level estimation is done by combining data regardless of State; thus avoiding the need to add State level estimates that may not all be available.

Source: Energy Information Administration, Form EIA-759, "Monthly Power Plant Report." Form EIA-860B, "Annual Electric Generator Report-Nonutility." Form EIA-900, "Monthly Nonutility Power Plant Report."

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Energy in the United States: A Brief History and Current Trends

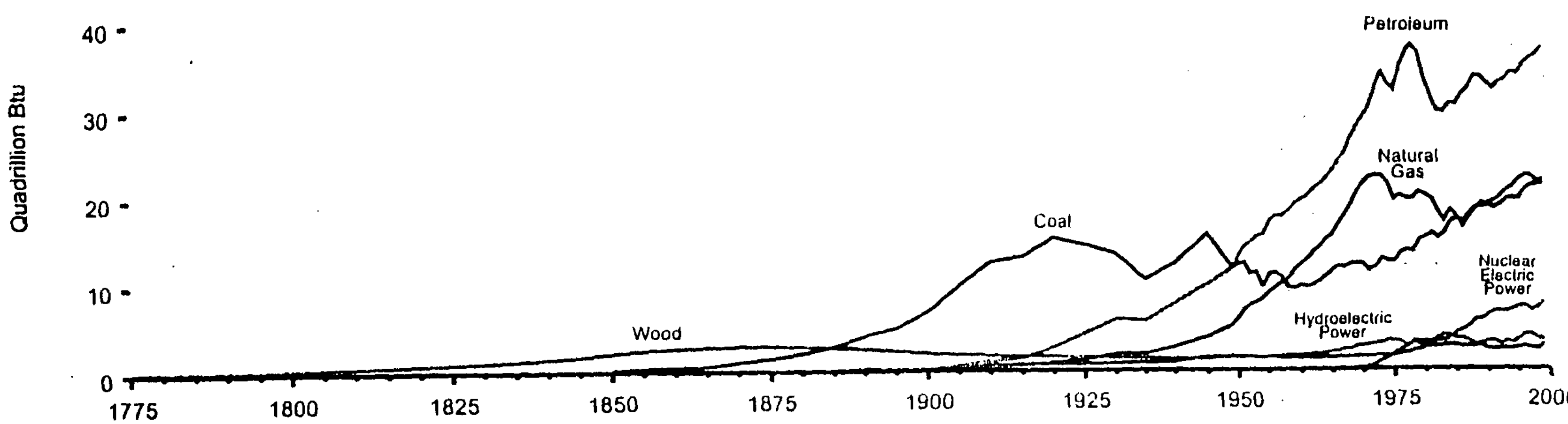
Energy is essential to life. Living creatures draw on energy flowing through the environment and convert it to forms they can use. The most fundamental energy flow for living creatures is the energy of sunlight, and the most important conversion is the act of biological primary production, in which plants and sea-dwelling phytoplankton convert sunlight into biomass by photosynthesis. The Earth's web of life, including human beings, rests on this foundation.

Over millennia, humans have found ways to extend and expand their energy harvest, first by harnessing draft animals and later by inventing machines to tap the power of wind and water. The watershed social and economic development of the modern world, industrialization, was accompanied by the widespread and intensive use of fossil fuels. This development freed human society from the limitations of natural energy flows by unlocking the Earth's vast stores of coal, oil, and natural gas. By tapping these ancient, concentrated deposits of solar energy, the rate at which energy could be poured into the human economy was enormously multiplied.

The result was one of the most profound social transformations in history. The new river of energy wrought astonishing changes and did so with unprecedented speed. The energy transformations experienced by traditional societies—from human labor alone to animal muscle power and later windmills and watermills—were very slow, and their consequences were equally slow to take effect. In contrast, industrialization and its associated socioeconomic changes took place in the space of a few generations.

The history of energy use in the United States reflects these general themes of transformation and its consequences. Consider the evolution of the U.S. energy mix. Wood energy has been a significant part of that mix for a very long time (Figure 1); in fact, fuelwood was overwhelmingly the dominant energy source from the founding of the earliest colonies until late in the last century. Thereafter, the modern era is notable for the accelerated appearance of new sources of energy, in contrast to the imperceptible pace of change in earlier times. Coal ended the long dominance of fuelwood in the United States about 1885, only itself to be surpassed in 1951 by petroleum and then

Figure 1. Energy Consumption in the United States, 1775-1999



by natural gas a few years later. Hydroelectric power and nuclear electric power appeared about 1890 and 1957, respectively. Solar photovoltaic, advanced solar thermal, and geothermal technologies also represent recent developments in energy sources. The most striking of these entrances, however, is that of petroleum and natural gas. The curves depicting their consumption remain shallow for several decades following the haphazard success of Colonel Drake's drilling rig in 1859, but begin to rise more steeply in the 1920s. Then, interrupted only by the Depression, the curves climb at increasingly alpine angles until 1973. Annual consumption of petroleum and natural gas exceeded that of coal in 1947 and then quadrupled in a single generation. Neither before nor since has any source of energy become so dominant so quickly.

As for the social, economic, and ecological consequences of evolving energy sources, they are too deep and numerous to do more than give suggestive examples. One of the most significant is the shift between muscle- and machine power. Horses, mules, and other draft animals were invaluable prime movers well into the first half of the 20th century, and despite increasing reliance on fossil fuels and the engines they powered, the number of draft animals in the United States continued to rise until about 1920. As late as 1870, draft animals accounted for more than half of the total horsepower of all prime movers. Their displacement by fossil-fuel driven engines meant, eventually, the disappearance from city and farm alike of millions of animals, along with the vast stables that housed the city-based animals, the mountains of dung they left on city streets, and the hordes of English sparrows that fed on the grain therein.

As fossil fuels and the machines that ran on them proliferated, the nature of work itself was transformed along with the fundamental social, political, and geopolitical circumstances of the Nation. In the middle of the 19th century, most Americans lived in the countryside and worked on farms. The country ran mainly on wood fuel and was relatively unimportant in global affairs. A hundred years later, after the Nation had become the world's largest producer and consumer of fossil fuels, most Americans were city-dwellers and only a relative handful were agricultural workers. The United States had roughly tripled its per-capita consumption of energy and become a global superpower.

Although coal, oil, and natural gas are the world's most important energy sources, their dominance does not extend to all corners of the globe. In most places and times diversity and evolution in energy supplies has been the rule. In many areas muscle power and biomass energy remain indispensable. The shifting emphasis over time is clear not only in the long sweep of history but also in the short term, especially in the industrialized world. Electricity, for example, was essentially unavailable until the 1880s; now it is ubiquitous. And as the data in this volume show, in the span of a few decades nuclear electric power in the United States was born, peaked, and began to decline in its contribution to total energy production.

No doubt we have not seen the end of evolution in energy sources. The pages that follow briefly discuss the major energy sources now in use in the United States, including a bit of history, trends, and snapshots of current consumption. The story they tell is one of diversity and transformation, driven by chance, the play of economic forces, and human ingenuity. Whatever energy future awaits us, that part of the story seems unlikely to change.

Total Energy

The United States has always been a resource-rich nation, but in 1776, the year the Nation declared its independence from Great Britain, nearly all energy was still supplied by muscle power and fuelwood. America's vast deposits of coal and petroleum lay untapped and mostly undiscovered, although small amounts of coal were used to make coke, vital for casting the cannon that helped win the war. Mills made use of waterpower, and of course the wind enabled transport by ship.

Fuelwood use continued to expand in parallel with the Nation's economic growth, but chronic shortages of energy in general encouraged the search for other sources. During the first 30 years or so of the 19th century, coal began to be used in blast furnaces and in making coal-gas for illumination. Natural gas also found limited application in lighting during the period. Even electricity sought a niche; for example, experiments were conducted with battery-powered electric trains in the 1840s and 1850s. Still, muscle power remained an important source of energy for decades. Although a number of mechanical innovations appeared, including the cotton gin and the mechanical reaper, they had the effect of multiplying the productivity of human and animal muscle power rather than spurring the development of machine power. It was not until well after mid-century that the total work output from all types of engines exceeded that of work animals.

The westward expansion helped change that. As railroads drove west to the plains and the mountains, they left behind the fuelwood so abundant along the eastern seaboard. Coal became more attractive, both because deposits were often found near the new railroad rights of way and because its higher energy content increased the range and load of steam trains. Demand for coal also rose because the railroads were laying thousands of miles of new track, and the metals industry needed an economical source of coke to make iron and steel for the rails and spikes. The transportation and industrial sectors in general began to grow rapidly during the latter half of the century, and coal helped fuel their growth.

Petroleum got its start as an illuminant and nostrum ingredient and did not catch on as a fuel for some time. At the end of World War I, coal still accounted for about 75 percent of U.S. total energy use. About the same time, the horse and mule population reached 26 million and then went into permanent decline. The beginning of the transition from muscle power was over.

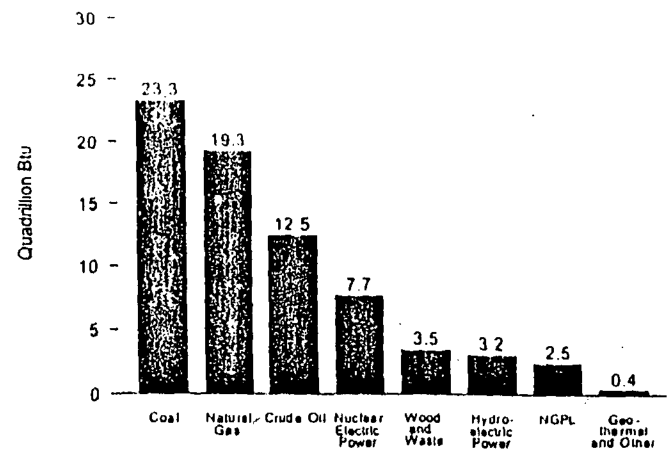
America's appetite for energy as it industrialized was prodigious, roughly quadrupling between 1880 and 1918. Coal fed much of this growth, while electricity expanded in applications and total use alike. Petroleum got major boosts with the discovery of Texas's vast Spindletop Oil Field in 1901 and with the advent of mass-produced automobiles, several million of which had been built by 1918.

In the years after World War II, "Old King Coal" relinquished its place as the premier fuel in the United States. The railroads lost business to trucks that ran on petroleum and also began switching to diesel locomotives themselves. Labor troubles and safety standards drove up coal production costs. The declining demand for natural gas as an illuminant forced that industry to look for other markets. Heating applications had obvious potential, and natural gas replaced coal in many household ranges and furnaces. The coal industry survived in part because nationwide electrification created new demand for coal among electric utilities despite regional competition from hydroelectric and petroleum-fired generation.

Most energy produced today in the United States, as in the rest of the industrialized world, comes from fossil fuels—coal, natural gas, crude oil, and natural gas plant liquids (Figure 2). Although U.S. energy production draws from many sources, fossil fuels together far exceed all other forms. In 1999 they accounted for 80 percent of total energy production and were valued at an estimated $94 billion (nominal dollars).

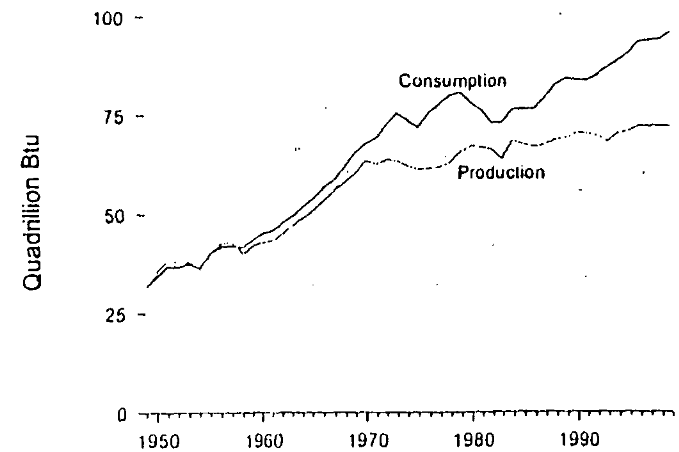
For much of its history, the United States was mostly self-sufficient in energy, although small amounts of coal were imported from Britain in colonial times. Through the late 1950s, production and consumption of energy

Figure 2. Energy Production, 1999



were nearly in balance. Over the following decade, however, consumption slightly outpaced domestic production and by the early 1970s a more significant gap had developed (Figure 3).

Figure 3. Production and Consumption



In 1999 the United States produced 73 quadrillion British thermal units (Btu) of energy and exported 4 quadrillion Btu, about 40 percent of it as coal. Consumption totaled 97 quadrillion Btu, requiring imports of 27 quadrillion Btu (Figure 4), 18 times the 1949 level.

This appetite for imported energy is driven by petroleum consumption. U.S. petroleum imports in 1973 totaled 6.3 million barrels per day (3.2 million barrels per day of crude oil and 3.0 million barrels per day of petroleum products). In October 1973, however, the Arab members of the Organization of Petroleum Exporting Countries (OPEC) embargoed the sale of oil to the United States, prices rose sharply, and petroleum imports fell for two years (Figure 5). They increased again until the price of crude oil rose dramatically (roughly 1979 through 1981) and suppressed imports. The rising-import trend resumed by 1986, and in 1998 U.S. petroleum net imports reached an annual record level of 9.8 million barrels per day. In 1999, net imports fell slightly to 9.6 million barrels per day.

The efficiency with which Americans use energy has improved over the years. One such measure is the amount of energy consumed to produce a (constant) dollar's worth of gross domestic product (GDP). By that measure, efficiency improved 47 percent between 1949 and 1999, as the amount of energy required to generate a dollar of output (chained 1996 dollars) fell from 20.6 thousand Btu to 10.9 thousand Btu. Nevertheless, a growing population and economy drove total energy use up. As the U.S. population expanded from 149 million people in 1949 to 273 million in 1999 (an increase of 83 percent), total energy consumption grew from 32 quadrillion Btu to 97 quadrillion Btu (up 202 percent). Per-capita energy consumption rose 65 percent, from 215 million Btu in 1949 to 354 million Btu in 1999.

Figure 4. Energy Flow, 1999
(Quadrillion Btu)

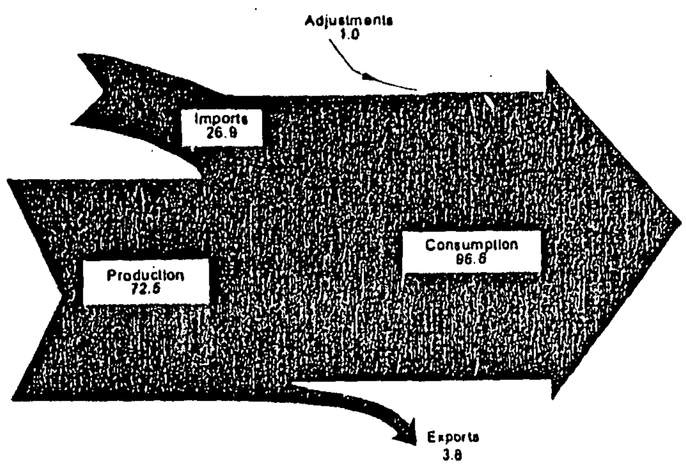
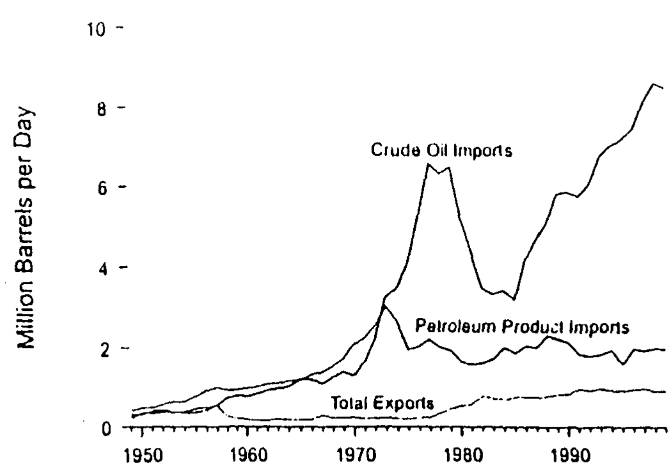


Figure 5. Petroleum Trade



Energy plays a central role in the operation of the industrialized U.S. economy, and energy spending is commensurately large. In recent years, American consumers have spent over half a trillion dollars a year on energy. That energy is consumed in three broad end-use sectors: the residential and commercial sector, the industrial sector, and the transportation sector. Industry, historically the largest consuming sector of the economy, ran just ahead of the residential and commercial sector in recent years, followed by the transportation sector (Figure 6).

The industrial sector reveals occasional sharp fluctuations in its use of energy. In contrast, trends in the residential and commercial sector are smoother. Within the sectors, energy sources have changed dramatically over time. For example, in the residential and commercial sector, coal was the leading source as late as 1951 but disappeared rapidly thereafter (Figure 7). Petroleum usage grew slowly to its peak in 1972 and then subsided. Natural gas became an important resource, growing strongly until 1972, when its growth stalled. Electricity, only an incidental source in 1949, expanded in almost every year since

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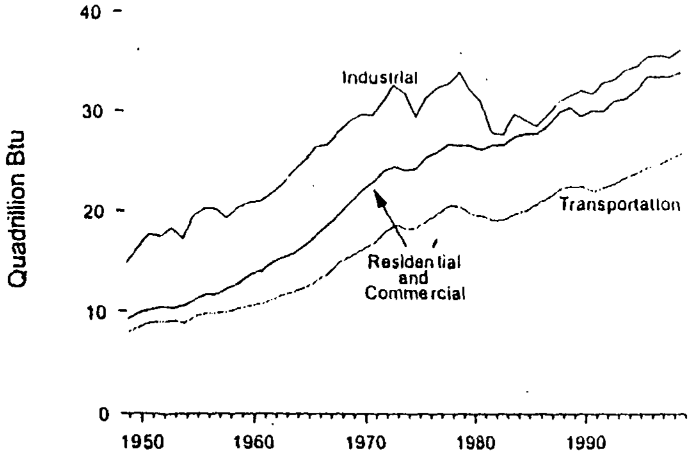
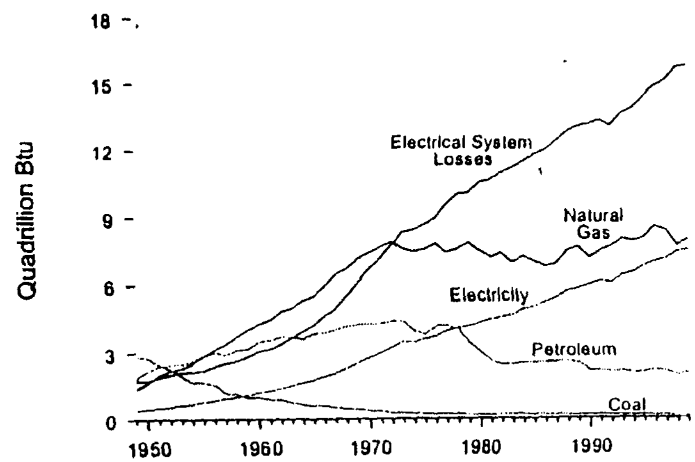
Figure 6. Energy Consumption by End-Use Sector



then, as did the energy losses associated with producing and distributing the electricity. (See page xxxi for an explanation of these losses.)

The expansion of electricity use reflects the increased electrification of U.S. households, which typically rely on a wide variety of electrical

Figure 7. Residential and Commercial Consumption



appliances and systems. In 1997, 99 percent of U.S. households had a color television and 47 percent had central air conditioning. Eighty-five percent of all households had one refrigerator; the remaining 15 percent had two or more. New products continued to penetrate the market; for example, in 1978 only 8 percent of U.S. households had a microwave oven, but by 1997 microwaves could be found in 83 percent. EIA first collected household survey data on personal computers in 1990, when 16 percent of households owned one or more. By 1997 that share had more than doubled to 35 percent.

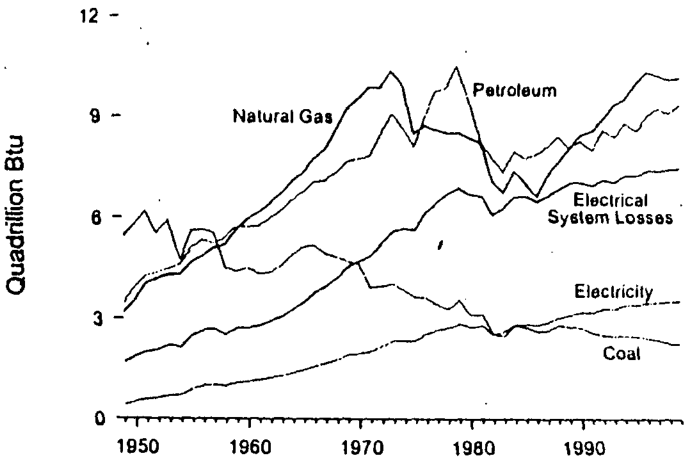
U.S. home heating also underwent a big change. Over a third of all U.S. housing units were warmed by coal in 1950, but by 1997 that share was only 0.2 percent. Distillate fuel oil lost just over half its share of the home-heating market during the same period, falling from 22 percent. Natural gas and electricity gained as home-heating sources: the share of natural gas rose from about a quarter of all homes to over half, while electricity's share shot up from only 0.6 percent in 1950 to 29 percent in 1997. In recent times, electricity and natural gas have been the most common sources of energy used by commercial buildings as well.

In the industrial sector, the consumption of both natural gas and petroleum rose steadily and in tandem until the oil embargo in 1973, after which their use fluctuated (Figure 8). Consumption of coal, once the leading source in the sector, shrank. Electricity and its associated losses grew steadily.

About three-fifths of the energy consumed in the industrial sector is used for manufacturing. The remainder goes to mining, construction, agriculture, fisheries, and forestry. Within manufacturing, large consumers of energy are the petroleum and coal products, chemicals and allied products, paper and allied products, and primary metal industries. Natural gas is the most commonly consumed energy source in manufacturing. The predominant end-use activity is process heating, followed by machine drive and then facility heating, ventilation, and air conditioning combined.

Just under 7 percent of all energy consumed in the United States is used for nonfuel purposes, such as asphalt and road oil for roofing products and road building and conditioning; liquefied petroleum gases for feedstocks at petrochemical plants; waxes for packaging, cosmetics, pharmaceuticals, inks, and adhesives; and still gas for chemical and rubber manufacture.

Figure 8. Industrial Consumption



While variety and change in energy sources are the hallmarks of the industrial sector and the residential and commercial sector, transportation's reliance on petroleum has been nearly total since 1949 (Figure 9).

Figure 9. Transportation Consumption

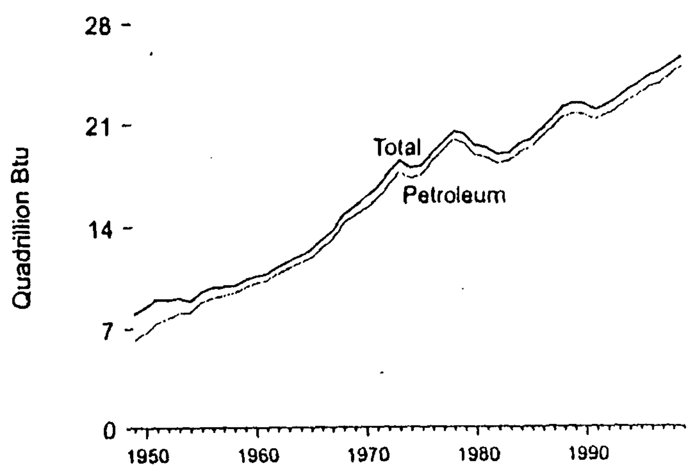
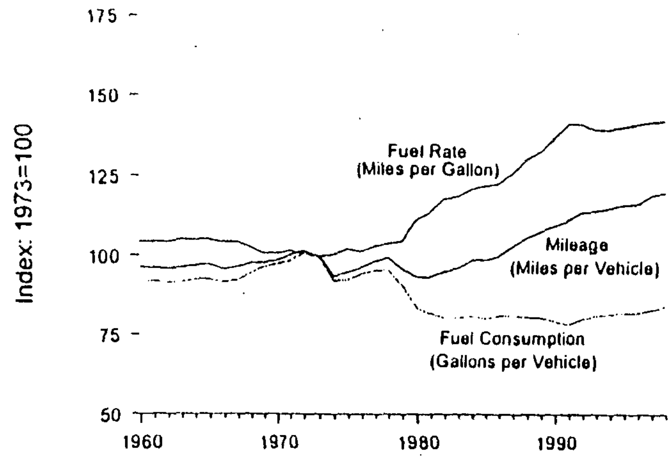


Figure 10. Motor Vehicle Efficiency



Compared with trends just prior to the oil embargo of 1973, fuel consumption per motor vehicle fell in the two decades that followed, miles traveled per vehicle generally fell until the early 1980s and then resumed a pattern of increase, and the fuel rate (i.e., miles per gallon) improved greatly (Figure 10).

Petroleum

It is hard to imagine a world without petroleum, partly because humans have been using it since at least 3000 B.C. Mesopotamians of that era used "rock oil" in architectural adhesives, ship caulks, medicines, and roads. The Chinese of two millennia ago refined crude oil for use in lamps and in heating homes. Seventh-century Arab and Persian chemists discovered that petroleum's lighter elements could be mixed with quicklime to make "Greek fire," the napalm of its day. From these scattered uses, petroleum has come to occupy a central place in modern civilization. Today petroleum still finds applications in buildings, shipping, medicine, roads, and warfare. It is crucial to many industries, including chemicals and agriculture. Needless to say, it dominates the world energy scene.

Petroleum was known to native peoples in the northeastern parts of what was to become the United States, and was put to various uses by some of them. A French military officer noted in 1750 that Indians living near Fort Duquesne (now the site of Pittsburgh) set fire to an oil-slicked creek as part of a religious ceremony. As settlement by Europeans proceeded, oil was discovered in many places in northwestern Pennsylvania and western New York—to the frequent dismay of the well-owners, who were drilling for salt brine.

In the mid-1800s expanding uses for oil extracted from coal and shale began to hint at the value of rock oil and encouraged the search for readily accessible supplies. This impetus launched the modern petroleum age, which began on a Sunday afternoon in August 1859 at Oil Creek, near Titusville in northwestern Pennsylvania. The credit has traditionally gone to "Colonel" Edwin L. Drake, a railroad conductor on sick leave employed by the Pennsylvania Rock Oil Company. After months of effort and many setbacks, Drake's homemade drilling rig drove down to 70 feet, and the bit came up coated with oil. Ironically, Drake wasn't there that day to witness the historic event. And except for the slow and uncertain mails of the time, which delayed a letter from his financial backers ordering him to cease operations, it might not have happened in Oil Creek at all.

"Great excitement ensued" following Drake's discovery, according to the account in the 1883 edition of *Mineral Resources of the United States*. The succeeding oil boom was driven by strong demand for lighting fuel and lubricants. Over the next four decades the boom spread to Texas and California in the United States and to Romania, Baku (in Azerbaijan), Sumatra, Mexico, Trinidad, Iran, and Venezuela. Overproduction temporarily drove prices down, but the rapid adoption and spread of internal combustion engines in the late 19th century helped create vast new markets. With only temporary interruptions, world petroleum consumption has expanded ever since.

Until the 1950s the United States produced nearly all the petroleum it needed. But by the end of the decade the gap between production and consumption began to widen and imported petroleum became a major component of the U.S. petroleum supply (Figure 11). After 1992, imports exceeded production.

Production of petroleum (crude oil and natural gas plant liquids) in the U.S. lower 48 States reached its highest level in 1970 at 9.4 million barrels per day (Figure 12). A surge in Alaskan oil output at Prudhoe Bay beginning in the late 1970s helped postpone the decline in overall U.S. production, but Alaska's production peaked in 1988 at 2.0 million barrels per day and fell to 1.0 million barrels per day in 1999. By then U.S. total output had dropped to 7.8 million barrels per day, 31 percent below its peak.

Figure 11. Petroleum Production and Consumption

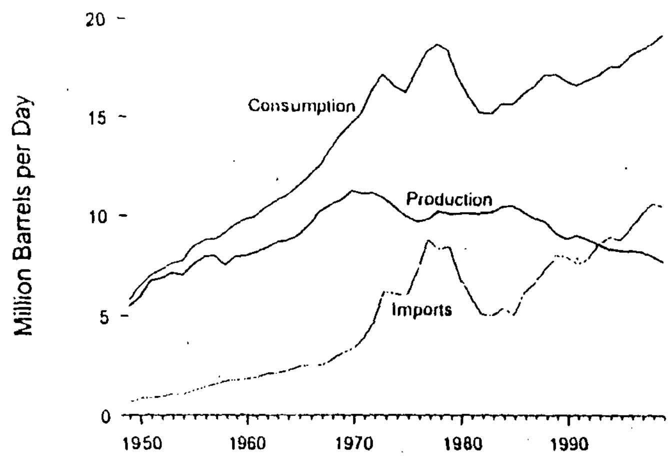
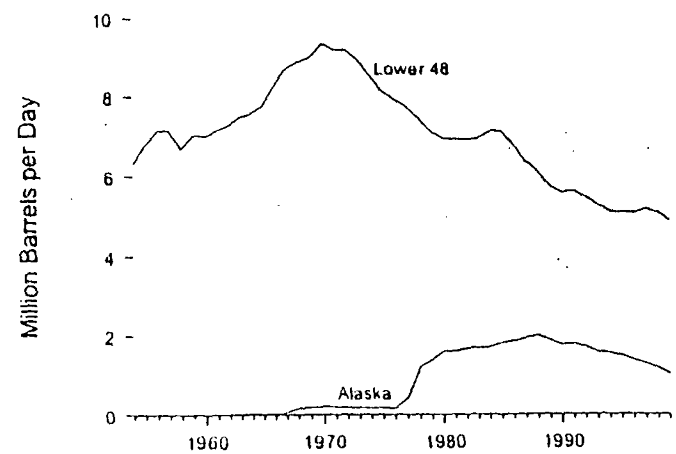


Figure 12. Lower 48 and Alaskan Crude Oil Production



Another index of the Nation's petroleum output is oil well productivity, which fell from a high of 18.4 barrels per day per well in 1972 to 10.7 barrels per day per well in 1999 (Figure 13).

U.S. petroleum consumption rose annually until 1973, when the Arab OPEC embargo stalled the annual increases for two years. The increases then resumed, raising consumption to 18.8 million barrels per day in 1978, before rising prices drove it down to a post-embargo low of 15.2 million barrels per day in 1983. Consumption began to rebound the following year and was boosted by plummeting crude oil prices in 1986. By 1999 it had reached 19.4 million barrels per day, an all-time high.

Of every 10 barrels of petroleum consumed in the United States in 1999, more than 4 barrels were consumed in the form of motor gasoline. The transportation sector alone accounted for two-thirds of all petroleum used in the United States in 1999 (Figure 14).

To meet demand, crude oil and petroleum products were imported at the rate of 10.5 million barrels per day in 1999, while exports measured 0.9 million barrels per day. Between 1985 (when net imports fell to a post-embargo low) and 1999, net imports of crude oil and petroleum products more than doubled from 4.3 million barrels per day to 9.6 million barrels per day. The share of U.S. net imports that came from OPEC nations reached 72 percent in 1977, subsided to 42 percent in 1985, and climbed back to 50 percent in 1999. Total net imports as a share of petroleum consumption reached a record high of 52 percent in

Figure 14. Petroleum Consumption by Sector

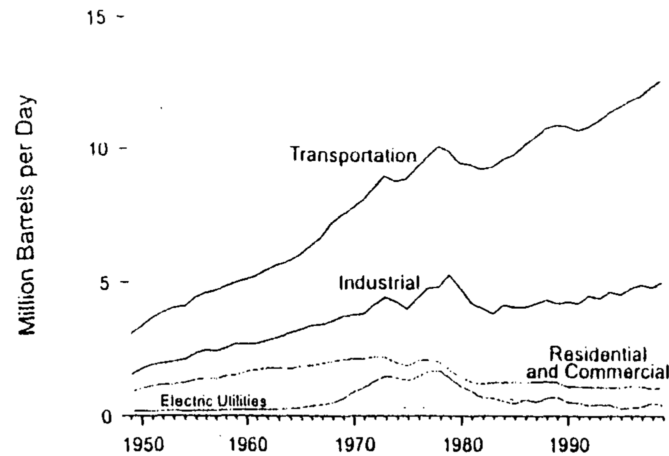


Figure 13. Oil Well Productivity

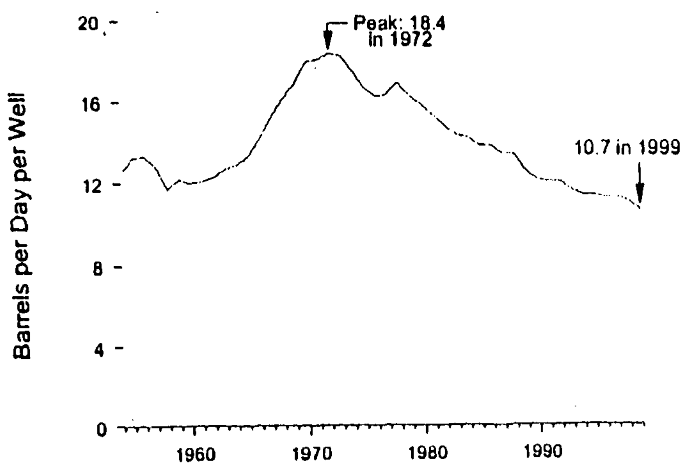


Figure 15. Strategic Petroleum Reserve Stocks

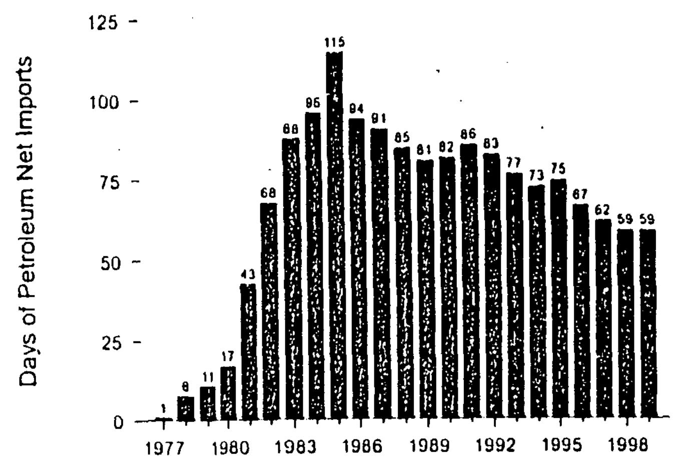
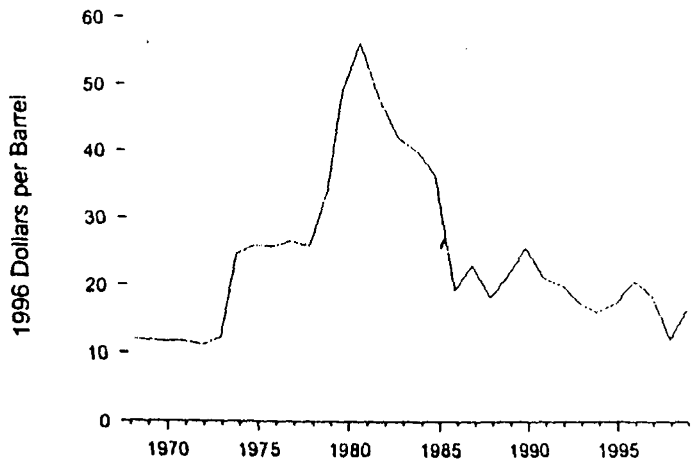


Figure 16. Inflation-Adjusted Cost of Crude Oil



1998 before declining to 50 percent the following year. The five leading suppliers of petroleum to the United States in 1999 were Saudi Arabia, Venezuela, Canada, Mexico, and Nigeria.

To protect against supply disruptions, the United States began to build a Strategic Petroleum Reserve in the late 1970s. By 1985 the reserve's holdings reached 493 million barrels, which would have provided enough crude oil to replace about 115 days' worth of net petroleum imports that year (Figure 15). In 1999, the reserve held 567 million barrels of crude oil. Due to the increased rate of imports, however, that amount would replace only 59 days' worth of net imported petroleum.

Despite recent price increases, petroleum remains relatively cheap in the United States. Refiners' acquisition costs for crude oil in 1999 averaged $17.46 per barrel. When adjusted for inflation, the cost was $16.69 (chained 1996 dollars), 37 percent above the previous year's cost but 70 percent below 1981's record inflation-adjusted cost of $56.50 per barrel (Figure 16).

Natural Gas

Natural gas is mostly a mixture of methane, ethane, and propane, with methane making up 73 to 95 percent of the total. Often encountered when drilling for oil, natural gas was once considered mainly a nuisance. When either uses or—more likely today—accessible markets were lacking, it was simply flared (burned off) at the wellhead. Major flaring sites were sometimes the brightest areas visible in nighttime satellite images. Today, however, the gas is mostly reinjected for later use and to encourage greater oil production.

The first practical use of natural gas dates to 200 B.C. and is attributed, like so many technical developments, to the Chinese. They used it to make salt from brine in gas-fired evaporators, boring shallow wells with crude percussion rigs and conveying the gas to the evaporators via bamboo pipes. Natural gas was used extensively in Europe and North America in the 19th century as a lighting fuel, until the rapid development of electricity beginning in the 1890s ended that era. The development of steel pipelines and related equipment, which allowed large volumes of gas to be easily and safely transported over many miles, launched the modern natural gas industry. The first all-welded pipeline over 200 miles in length was built in 1925, from Louisiana to Texas. U.S. demand for natural gas grew rapidly thereafter, especially following World War II. Residential demand grew fifty-fold between 1906 and 1970.

Figure 17. Natural Gas Overview

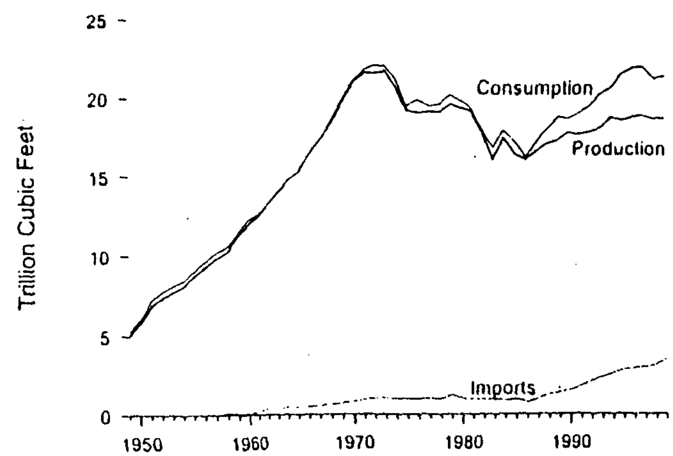


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Figure 18. Natural Gas Net Imports as Share of Consumption

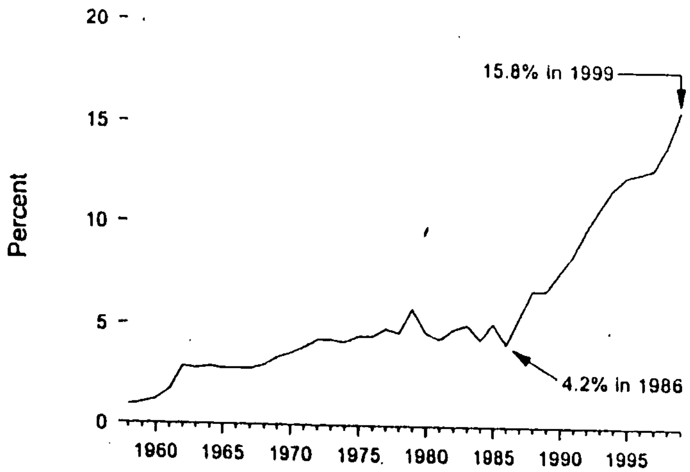
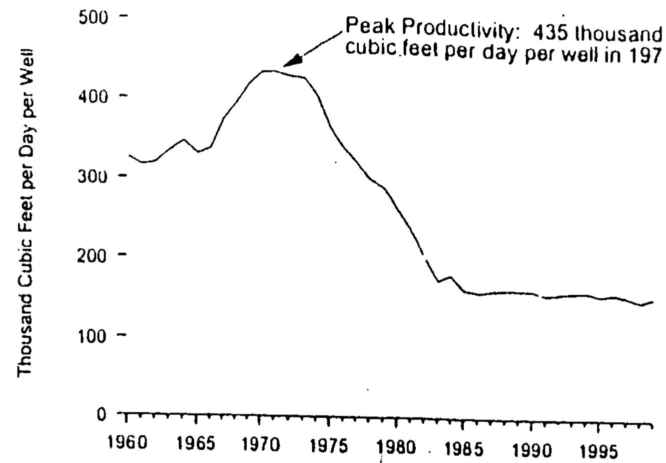


Figure 19. Natural Gas Well Productivity



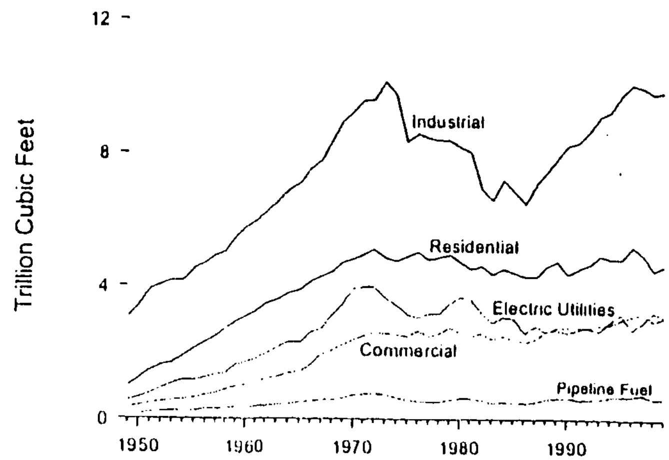
The United States had large natural-gas reserves and was essentially ~~self-sufficient in natural gas until the late 1980s, when consumption~~ began to significantly outpace production (Figure 17). Imports rose to make up the difference, nearly all coming by pipeline from Canada, although small volumes were brought by tanker in liquefied form from Algeria and, in recent years, from a few other countries as well. Net imports as a share of consumption more than tripled from 1986 to 1999 ~~(Figure~~ 18).

U.S. natural gas production in 1999 was 18.7 trillion cubic feet, well below the record-high 21.7 trillion cubic feet produced in 1973. Gas well productivity peaked at 435 thousand cubic feet per well per day in 1971, then fell steeply through the mid-1980s before stabilizing. Productivity in 1999 was 157 thousand cubic feet per well per day (Figure 19).

Three States (Texas, Louisiana, and Oklahoma) account for over half of all natural gas produced in the United States. Texas alone produced 6.9 trillion cubic feet in 1999. Advancing drilling technology has made offshore sites more important, and over the last two decades about one-fifth of all U.S. production has come from offshore sites.

~~For decades, the industrial~~ sector of the economy has been the heaviest user of natural gas (Figure 20). In 1999 industrial entities (including most electric power producers other than utilities) accounted for nearly half of all natural gas consumption, followed by the residential sector, which used another fifth of the total. In recent years, very small amounts of natural gas (about 5 billion cubic feet in 1998) have been reported for use in vehicles.

Figure 20. Natural Gas Consumption by Sector



The price of natural gas at the wellhead (i.e., where the gas is produced) was $1.98 per thousand cubic feet in 1999, in real terms (chained 1996 dollars), well below the historical high of $3.76 per thousand cubic feet in 1983. In nominal dollars, the 1999 wellhead price was $2.07 per thousand cubic feet.

Coal

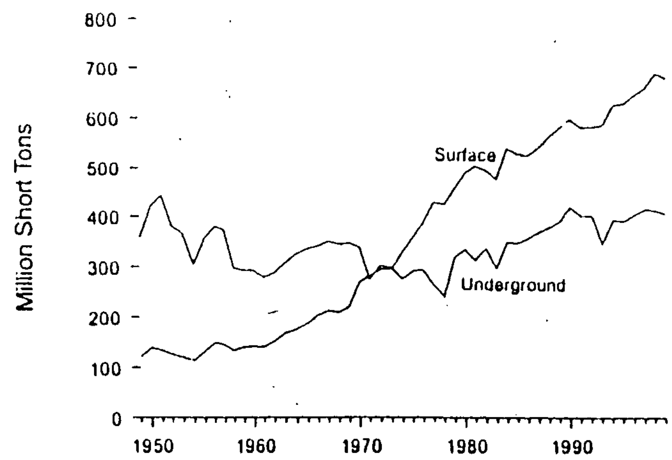
Scattered records of the use of coal as a fuel date from at least 1100 B.C. However, coal was not used extensively until the Middle Ages, when small mining operations in Europe began to supply it for forges, smithies, lime-burners, and breweries. The invention of firebricks in the late 1400s, which made chimneys cheap to build, helped create a home heating market for coal. Despite its drawbacks (smoke and fumes), coal was firmly established as a domestic fuel by the 1570s. By that time, production in England was high enough that exports were thriving. Eventually, some of that coal went to the American colonies.

The total amount of coal consumed in the United States in all the years before 1800 was an estimated 108,000 tons, much of it imported. The U.S. market for coal expanded slowly and it was not until 1885 that the young and heavily forested nation burned more coal than wood. However, the arrival of the industrial revolution and the development of the railroads in the mid-nineteenth century inaugurated a period of generally growing production and consumption of coal that continues to the present time. Today, the United States extracts coal in enormous quantities. In 1998 U.S. production of coal reached a record 1.12 billion short tons and was second worldwide after China. U.S. 1999 production was 1.10 billion short tons.

From 1885 through 1951, coal was the leading source of energy produced in the United States. Crude oil and natural gas then vied for that role until 1982. Coal regained the position of the top resource that year and again in 1984, and has retained it since. At 23 quadrillion Btu in 1999, coal accounted for a third of all energy produced in the country.

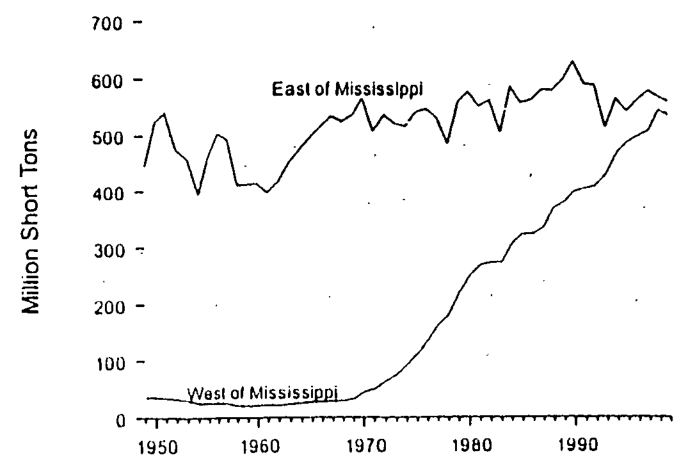
Over the past several decades, coal production shifted from primarily underground mines to surface mines (Figure 21). In addition, the coal resources of Wyoming and other areas west of the Mississippi River underwent tremendous development (Figure 22).

Figure 21. Coal Production by Mining Method



Technological improvements in mining and the shift toward more surface-mined coal, especially west of the Mississippi, have led to great improvements in coal mining productivity. In 1949 U.S. miners produced 0.7 short tons of coal per miner hour; by 1998 that rate had increased to 6.2 short tons per miner hour.

Figure 22. Coal Production by Location



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Since 1950, the United States has produced more coal than it has consumed. The excess production allowed the United States to become a significant exporter of coal to other nations. In 1999 U.S. coal exports totaled 58 million short tons, which, measured in Btu, accounted for 40 percent of all U.S. energy exports. About 38 percent of the year's coal exports went to Europe, while the individual nations buying the most American coal were Canada, Japan, Brazil, Italy, and the Netherlands. While the quantities of coal leaving the country are huge, in 1999 they represented only 7 percent of the Btu content of the petroleum coming *into* the United States.

The uses of coal in the United States have changed dramatically over the years. In the 1950s, most coal was consumed in the industrial sector, but many homes were still heated by coal and the transportation sector still consumed significant amounts in steam-driven trains and ships (Figure 23). In 1999 the industrial sector used less than half as much coal as in 1949. Today only 9 percent of all coal consumed in the United States goes to the industrial sector. Ninety percent is used in the electric power sector; coal-fired units accounted for 51 percent of U.S. electricity generation in 1999 (Figure 24).

Coal-fired electric generating units emit gases that are of environmental concern. In 1998 U.S. carbon dioxide emissions from the combustion of coal for electric utility generation were nearly half a billion metric tons of carbon, 32 percent of total carbon dioxide emitted from all U.S. fuel sources.

Figure 23. Coal Consumption by Sector

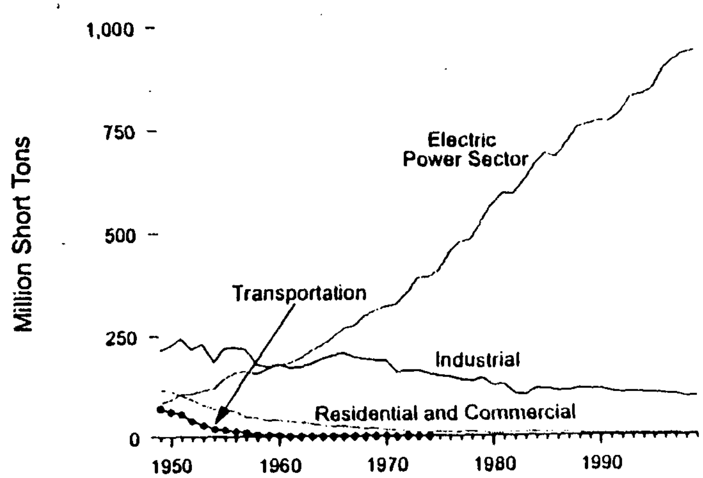
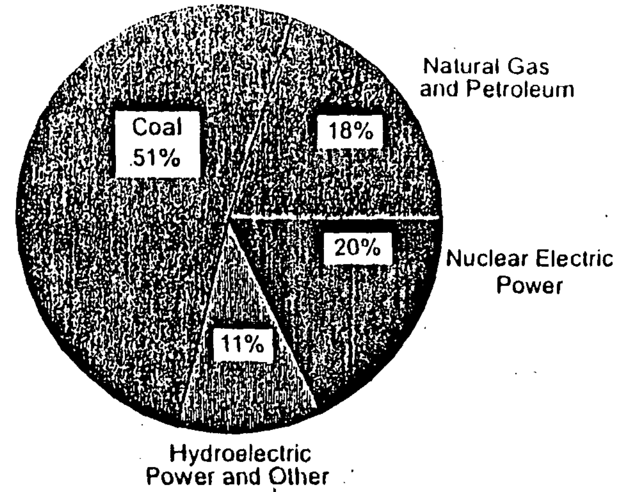


Figure 24. Electricity Net Generation by Source, 1999



Except for a post-oil-embargo price spike that peaked in 1975, real (inflation adjusted) coal prices have generally fallen over the last half-century. The average price in 1999 was 44 percent lower than it was in 1949. Coal is the least expensive of the major fossil fuels in this country: in nominal dollars, 1999 production prices for coal were 84 cents per million Btu compared with $1.86 per million Btu for natural gas and $2.68 per million Btu for crude oil.

Electricity

Electric power arrived barely a hundred years ago, but it has radically transformed and expanded our energy use. To a large extent, electricity defines modern technological civilization.

The reasons may not be easy to appreciate for those who have never known the filth, toil, danger, scarcity and/or inconvenience historically associated with obtaining and deploying such fuels as wood, coal, and whale oil. By contrast, at the point of use electricity is clean, flexible, controllable, safe, effortless, and instantly available. In homes, it runs everything from toothbrushes and televisions to heating and cooling systems. Outdoors, electricity guides traffic, aircraft, and ships, and lights up the night. In business and industry, electricity enables virtually instantaneous global communication and powers everything from trains, auto plant assembly lines, and restaurant refrigerators to the computers that run the New York Stock Exchange and the automatic pin-setting machines at the local bowling alley.

Electric power developed slowly, however. Humphrey Davy built a battery-powered arc lamp in 1808 and Michael Faraday an induction dynamo in 1831, but it was another half-century before Thomas Edison's primitive cotton-thread filament burned long enough to prove that a workable electric light could be made. Once past that hurdle, progress accelerated. Edison opened the first electricity generating plant (in London) less than 3 years later, in January 1882, and followed with the first American plant (in New York) in September. Within a month, electric current from New York's Pearl Street station was feeding 1,300 lightbulbs, and within a year, 11,000—each a hundred times brighter than a candle. Edison's reported goal was to "make electric light so cheap that only the rich will be able to burn candles."

Though he fathered the electric utility industry, Edison failed in his attempts to dominate its business and technical sides. Other companies surpassed his efforts to build central power stations, and Edison's dogged faith in direct current (DC) betrayed him. DC could only be transmitted 2 miles, while a rival alternating-current (AC) system developed by George Westinghouse and Nikola Tesla (whom Edison had fired) enabled long-distance transmission of high-voltage current and stepdowns to lower voltages at the point of use—essentially the system in place today. Edison even subsidized construction of an AC-powered electric chair to convince the public that AC was dangerous, but to no avail.

The process of electrification proceeded in fits and starts. Industries like mining, textiles, steel, and printing electrified rapidly during the years between 1890 and 1910. Electricity's penetration of the residential sector was slowed by competition from gas companies, which had a large stake in the lighting market. Nevertheless, by 1900 there were 25 million electric incandescent lamps in use and homeowners had been introduced to electric stoves, sewing machines, curling irons, and vacuum cleaners. In parallel, generating equipment and distribution systems developed to meet the demand. By 1903 utility executive Samuel Insull had commissioned a 5 megawatt steam-driven turbine generator—the first of its type and the largest of any generator then built—and launched a revolution in generating hardware.

The cities received electric service first, because it has always been cheaper, easier, and more profitable to supply large numbers of customers when they are close together. High costs and the Great Depression, which dried up most investment capital, delayed electric service to rural Americans until President Franklin Roosevelt signed into law the Rural Electrification Administration (REA) in 1935. The REA loaned money at low interest and helped to set up electricity cooperatives. Though interrupted by World War II, rural electrification proceeded rapidly thereafter. By 1967 more than 98 percent of American farms were using electricity from central station power plants.

The depth of electricity's penetration into our economy and way of life is reflected in the fact that, over the last half century, annual increases in total electricity sales by electric utilities faltered only twice, in 1974 and 1982; in every other year, sales grew. From 1949 to 1999, while the population of the United States expanded 83 percent, the amount of electricity sold by utilities grew 1,180 percent. Per-capita average consumption of electricity in 1999 was seven times as high as in 1949. Electricity's broad usage in the economy can be seen in the sector totals, which were led in 1999 by the residential sector, followed closely by the industrial sector, and then the commercial sector (Figure 25).

Where does all this electricity come from? In the United States, coal has been and continues to be the source of most electricity, accounting for over half of all electricity generated by utilities in 1999 (Figure 26).

Figure 25. Electric Utility Retail Sales of Electricity, 1999

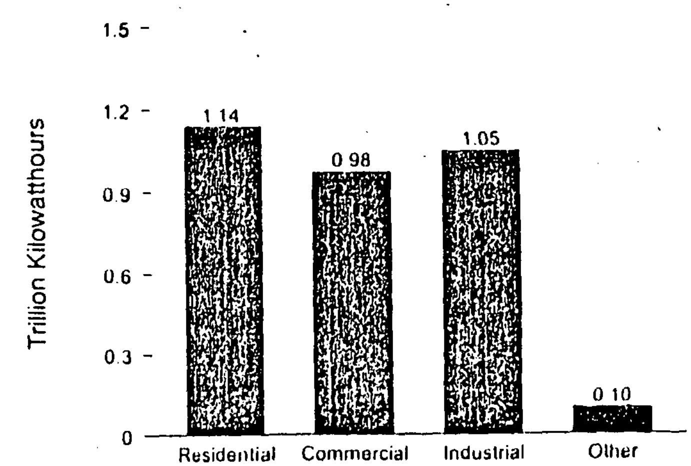


Figure 26. Electricity Net Generation at Utilities

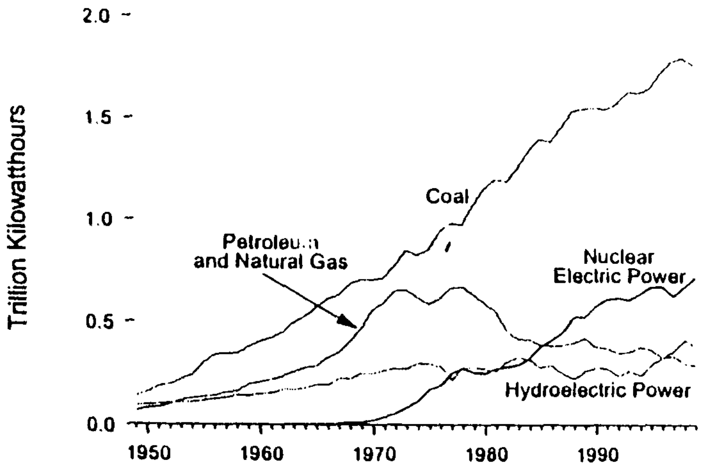
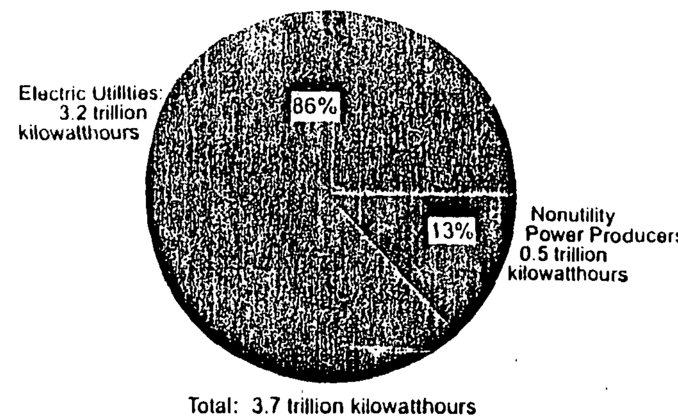


Figure 27. Electricity Net Generation, 1999

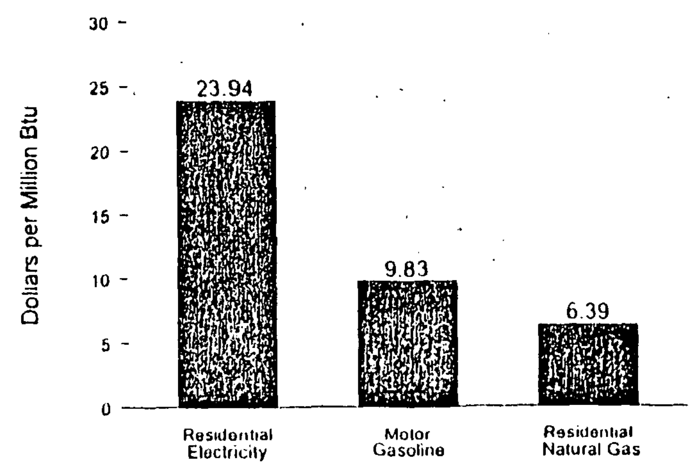


Hydroelectric power was an early source of U.S. electricity—accounting for almost a third of all utility generation in 1949—and remains a dependable contributor (over 9 percent of the total in 1999). Natural gas and petroleum grew steadily as sources of electricity in the late 1960s. Their combined usage peaked at 37 percent of the total in 1972 and stood at 18 percent in 1999. Meanwhile, a new source entered the picture: nuclear electric power. A trickle of nuclear electricity began flowing in 1957, and the stream widened steadily except for downturns in 1979 and 1980, following the accident at Three Mile Island, and again in 1993. Nuclear generation declined 7 percent in 1997 but rebounded 16 percent between 1997 and 1999.

Just as electricity's applications and sources change over time, so is the structure of the electric power sector itself evolving. The sector is now moving away from the traditional, highly regulated organizations known for many decades as electric utilities and toward an environment marked by lighter regulation and greater competition from and among nonutility power producers. In 1999, 13 percent of the total net generation of electricity came from nonutility power producers, such as independent power producers and nonutility cogenerators (Figure 27).

Electricity's great assets as a form of energy are reflected in its cost to the end user. The price paid by the consumer includes the cost of converting the energy from its original form, such as coal, into electricity and the cost of delivering it. In 1999 consumers paid an average of $23.94 per million Btu for the electricity delivered to their residences (Figure 28). In contrast, consumers paid an average of only $6.39 per million Btu for the natural gas

Figure 28. Consumer Prices, 1999



purchased for their homes and an average of $9.83 per million Btu for the motor gasoline to fuel their vehicles.

The unit cost of electricity is high because most of the energy that must be purchased to generate it does not actually reach the end user but is expended in creating the electricity and moving it to the point of use. In 1999, for example, approximately 35 quadrillion Btu of energy were consumed to generate electricity at utilities in the United States, but only 11 quadrillion Btu worth of electricity were actually used directly by consumers. Where did the other 24 quadrillion Btu go? Energy is never destroyed but it does change form. The chemical energy contained in fossil fuels, for example, is converted at the generator to the desired electrical energy. Because of theoretical and practical limits on the efficiency of conversion equipment, much of the energy in the fossil fuels is "lost," mostly as waste heat. The overall energy efficiency of a system can be increased through the tandem production of electricity and some form of useful thermal energy. This process, known as cogeneration, reduces waste energy by utilizing otherwise unwanted heat in the form of steam, hot water, or hot air for other purposes, such as operating pumps or for space heating or cooling.

In addition to the conversion losses, line losses occur during the transmission and distribution of electricity as it is transferred via connecting wires from the generating plant to substations (transmission), where its voltage is lowered, and from the substations to end users (distribution), such as homes, hospitals, stores, schools, and businesses. The generating plant itself uses some of the electricity. In the end, for every three units of energy that are converted to create electricity, only about one unit actually reaches the end user.

Nuclear Energy

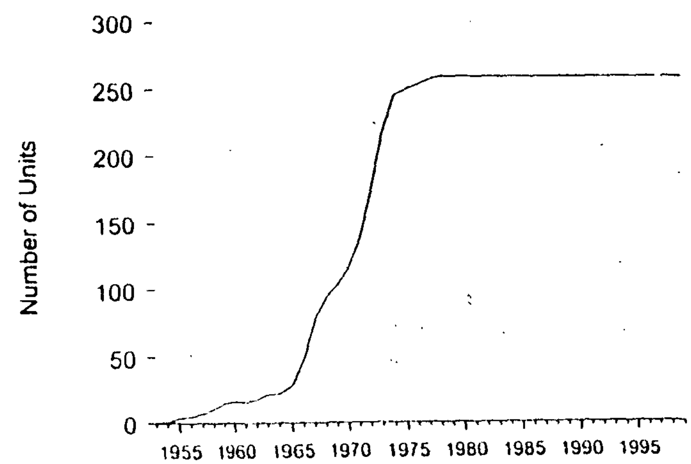
Among all the major forms of energy now in use, only nuclear power is native to the 20th century. The central insight—that the controlled fission of heavy elements could release enormous energies—came to British physicist Ernest Rutherford in 1904, and research during the 1930s convinced scientists that a controlled chain reaction was possible. Enrico Fermi's group achieved such a reaction for the first time in December 1942 at the University of Chicago in a primitive graphite-moderated reactor built on a vacant squash court.

World War II postponed further progress toward commercial nuclear electric power, but the theoretical foundation had been established and several factors encouraged nuclear power's development when peace returned. It was believed that fuel costs would be negligible and therefore that nuclear power would be relatively inexpensive. In addition, both the United States and Western Europe became net importers of crude oil in the early 1950s and nuclear power was seen as critical to avoiding energy dependence. Geopolitics appear to have played a role as well; President Dwight Eisenhower's Atoms for Peace program was intended in part to divert fissionable materials from bombs to peaceful uses such as civilian nuclear power.

In 1951 an experimental reactor sponsored by the U.S. Atomic Energy Commission generated the first electricity from nuclear power. The British completed the first operable commercial reactor, at Calder Hall, in 1956. The U.S. Shippingport unit, a design based on power plants used in nuclear submarines, followed a year later. In cooperation with the U.S. electric utility industry, reactor manufacturers then built several demonstration plants and made commitments to build additional plants at fixed prices. This commitment helped launch commercial nuclear power in the United States.

The success of the demonstration plants and the growing awareness of U.S. dependency on imported crude oil led to a wave of enthusiasm for

Figure 29. Cumulative Orders for Nuclear Generating Units



nuclear electric power that sent orders for reactor units soaring between 1966 and 1974 (Figure 29). The number of operable units increased in turn, as ordered units were constructed, tested, licensed for full power operation, and connected to the electricity grid (Figure 30). However, the curve of operable units lagged behind the curve of ordered units somewhat because of the long construction times required for the large, complex plants. The total number of U.S. operable reactor units peaked in 1990 at 112.

Orders for new units fell off sharply after 1974. Of the total of 259 units ordered to date, none was ordered after 1978. Although safety concerns, especially after the accident at Three Mile Island in 1979, reinforced a growing wariness of nuclear power, the chief reason for its declining momentum in the United States was economic. The promise of nuclear electric power had been that it would, in the now-famous phrase, make energy "too cheap to meter." In reality, nuclear power plants have always been costly to build and, for several reasons, became radically more costly between the mid-1960s and the mid-1970s. Utilities began building large plants before much experience had been gained with small ones. Expected economies of scale did not materialize. Many units were forced to undertake costly design changes and equipment retrofits, partially as a result of the Three Mile Island accident. Meanwhile, nuclear power plants have also had to compete with conventional coal- or natural gas-fired plants with declining operating costs.

Figure 30. Operable Nuclear Generating Units

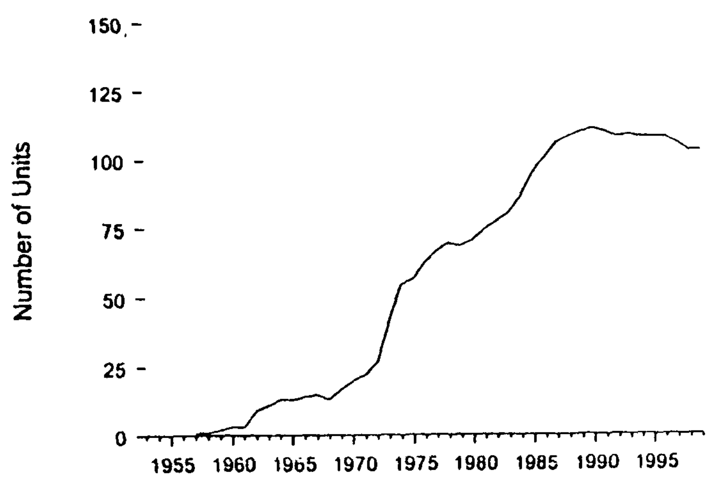
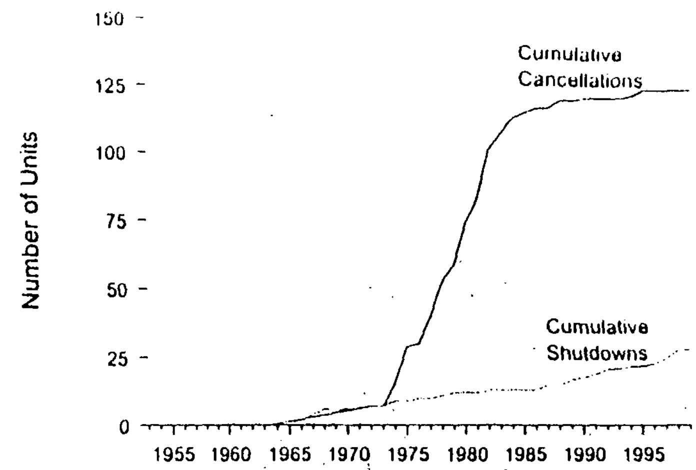


Figure 31. Nuclear Generating Units Cancelled or Shut Down



These trends disillusioned many utilities and investors. Interest in further orders subsided and many ordered units were cancelled before they were built. By the end of 1999, 124 units had been cancelled, 48 percent of all ordered units (Figure 31).

The average capacity factor of U.S. nuclear units—the ratio of the electricity they actually produced in a given year to the electricity they could have produced if run at continuous full power—has improved steadily over the years, and reached 86 percent in 1999. However, as operable nuclear power plants have aged, some have become uneconomic to operate or have otherwise reached the end of their useful lives. By the end of 1999, 28 once-operable units had been shut down permanently. The joint effect of shutdowns and lack of new units coming on line is that the number of U.S. operable units has fallen off since 1990 to 104. In its *Annual Energy Outlook 2000*, EIA projects that 41 percent of the nuclear generating capacity that existed at the end of 1998 will be retired by 2020. No new plants are expected to be built during the period.

Renewable Energy

For all but the most recent fraction of humanity's time on Earth, virtually all energy was renewable energy. Prior to the widespread use of fossil fuels and nuclear power, which arrived only an eyeblink ago in relative terms, there was essentially nothing else. Our ancestors warmed themselves directly in the sun, burned brush and fuelwood fashioned by photosynthesis from sunlight and nutrients, harnessed the power of wind and water created mainly by sun-driven atmospheric and hydrologic cycles, and of course used their own musclepower and that of animals.

We still depend heavily on renewable energy in these primeval forms. But various cultures have also found more inventive means of harnessing renewable resources, from mounting sails on wheelbarrows, as did ancient Chinese laborers, to gathering and burning buffalo dung, as did American settlers making their way west. The story of renewable energy is one of the invention and refinement of technologies for extracting both more energy and more useful forms of it from a wider variety of renewable sources. Many energy experts believe that the age of fossil fuels is only an interlude between pre- and post-industrial eras dominated by the use of renewable energy.

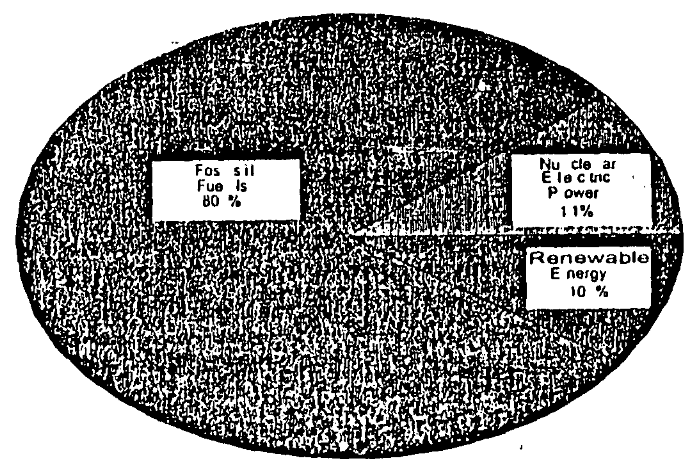
Some renewable energy technologies, such as water- and wind-driven mills, have been in use for centuries. Grain mills powered by waterwheels have existed since at least the first century B.C. and became commonplace long ago. In England, for example, the Domesday Book survey of 1086 counted 5,624 mills in the south and east alone. They were to be found throughout Europe and elsewhere and were used for a wide variety of mechanical tasks in addition to milling, from pressing oil to making wire. Some installations were surprisingly large. The Romans built a mill with 16 wheels and an output of over 40 horsepower near Arles in France. A giant 72-foot waterwheel with an output of 572 horsepower, dubbed Lady Isabella, was erected at a mine site on the Isle of Man in 1854. Further development of waterwheels ended with the invention of water turbines. Both types of machines were supplanted by large steam engines, which could be sited nearly anywhere. Turbines, however, found an important niche with the development of hydroelectric power.

Windmills are a younger but still ancient technology, dating at least to the 10th century in the Middle East, a bit later in Europe. In one form or another, windmills have remained in use ever since, for milling grain, pumping water, working metal, sawing, and crushing chalk or sugar cane. As mentioned in the introduction, American farms of the 19th century erected millions of small windmills to pump water for livestock or household use. In the modern era, technologically advanced windmills have been developed for generating electricity.

Modern renewable sources in the United States contribute about as much (roughly one-tenth) to total energy production as does nuclear power (Figure 32). Just as water power was relatively more important than wind energy in pre-industrial times, renewable energy today is dominated by hydroelectric power. About 45 percent of the U.S. renewable total in 1999 came from hydroelectric power generation, which uses dam-impounded water to drive turbine generators that make electricity. The American hydropower infrastructure is extensive and includes the great dams of the intermountain West, the Columbia basin, and the Tennessee River valley, as well as hundreds of other smaller installations nationwide.

Most of the rest of the U.S. renewable energy total came from wood and waste, a diverse category that includes not only the obvious candidates (such as wood, methanol, and ethanol) but also peat, wood liquors, wood sludge, railroad ties, pitch, municipal solid waste, agricultural waste, straw, tires, landfill gas, fish oil, and other things. Wood and wood byproducts are the most heavily used form of biomass and figure prominently in the energy consumption of such industries as paper manufacturing and lumber, which have ready access to them. Geothermal was third in 1999, accounting for about 5 percent of U.S. renewable energy production.

Figure 32. Renewable Energy in Total Energy Production, 1999



Despite their cachet, solar energy (photovoltaic and thermal) and wind energy contribute relatively little to the renewable total (about 1 percent and one-half percent respectively). The peak year for U.S. manufacturers' shipments of solar thermal collectors was 1981, when 21 million square feet were shipped. From 1991 through 1998, an average of 7.4 million square feet were shipped each year. Over 90 percent of the solar thermal collectors went to the residential sector in 1998. Ninety-three percent of the newly shipped collectors were used to heat swimming pools, while 6 percent were used for water heating and less than 1 percent for space heating. Prices for photovoltaic cells have fluctuated in recent years, while the volume of shipments in 1998 was nearly nine times the 1985 volume. U.S. wind energy production rose 58 percent between 1989 and 1999 but remains a very small factor in renewable energy here.

Environmental Indicators

The use of energy brings undisputed benefits, but it also incurs costs. Some of these costs show up on consumers' utility bills. The charges levied on consumers by an energy producer (an electric utility with a coal-fired generating plant, for instance) are designed to cover the producer's costs of building the power plant, extracting coal from the ground, transporting it to the power plant, crushing it to the proper size for combustion, maintaining the generating turbines, paying workers and managers, and so on.

One important category of costs that often is not reflected in consumers' bills is energy-related environmental effects. These unwanted effects can be thought of as the tail end of the energy cycle, which begins with extraction and processing of fuels (or gathering of wind or solar energy), proceeds with conversion to useful forms by means of petroleum refining, electricity generation, and other processes, and then moves on to distribution to, and consumption by, end-users. Once the energy has rendered the services for which it is consumed, all that is left are the byproducts of energy use, i.e., waste heat, mine tailings, sulfur dioxide and carbon dioxide gases, spent nuclear fuel, and many others.

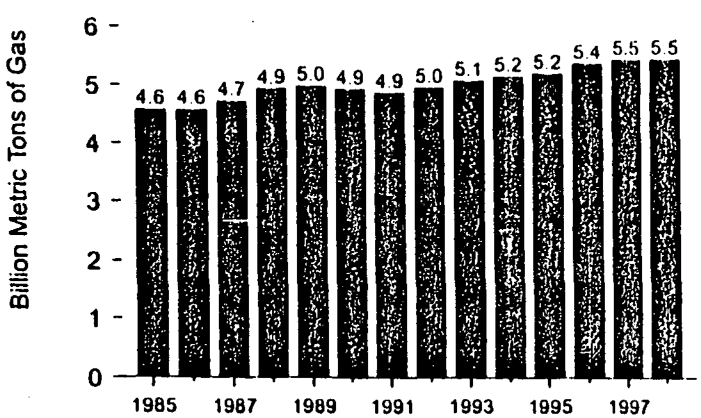
All energy use has unwanted effects of one kind or another; even a simple campfire produces eye-stinging smoke as well as warmth. The effects can be local or widespread, and neither type is only a concern of modern times. King Edward I of England, for instance, so objected to the noxious smoke and fumes from London's many coal-burning fires that in 1306 he tried (unsuccessfully) to ban its use by anyone except blacksmiths. But the enormous scale of modern energy use has sharply increased concerns about unwanted environmental effects. No form of energy production is entirely free of them, including renewable energy. Damming rivers and streams for hydropower facilities radically alters natural stream flows in ways that can threaten or endanger aquatic species. Wind-turbine generators can make noise and kill birds. Biomass generating plants that rely on plantation forestry for fuel can displace natural forest habitat and reduce biological diversity.

Among the most significant environmental effects of energy production and consumption is the emission of greenhouse gases. Such gases—carbon dioxide, methane, nitrous oxide, and others—block infrared radiation from the Earth to space and retain the captured heat in the atmosphere. This greenhouse effect keeps the Earth's climate hospitable to life. But the possibility of carbon-dioxide-forced warming of the climate has been postulated since 1861, and in recent years many scientists have come to believe that anthropogenic (human-caused) additions to greenhouse gases are raising global average temperatures and may produce harmful changes in the global climate. Energy-related greenhouse gas emissions make up a significant fraction of all such emissions, and the United States, as one of the world's largest producers and consumers of fossil fuels, is responsible for a major portion of global energy-related emissions.

Carbon dioxide (CO_2) accounts for the largest share of combined anthropogenic greenhouse gas emissions. In 1998 U.S. anthropogenic CO_2 emissions totaled about 5.5 billion metric tons (of gas; 1 ton of carbon equals 3.667 tons of carbon dioxide gas), 0.2 percent higher than the year before and 20 percent higher than in 1985 (Figure 33). Nearly 99 percent of this total was energy-related emissions, especially from petroleum consumed by the transportation sector, coal burned by electric utilities, and natural gas used by industry, homes, and businesses.

Energy-related emissions of methane, another important greenhouse gas, remained at 10 million metric tons in 1998. While about 35 percent of U.S. methane emissions stemmed from energy use, most came from landfills and such agricultural sources as ruminant animals (cattle and sheep) and their wastes. Emissions of a third potent greenhouse gas, nitrous oxide, remained about the same in 1998, at 1.2 million metric tons.

Figure 33. Carbon Dioxide Emissions



All sectors of the U.S. economy contribute to energy-related greenhouse gas emissions, especially CO_2. Of 1998 energy-related CO_2 emissions of 1.5 billion metric tons of carbon (5.4 billion tons of gas), the industrial and transportation sectors each accounted for about one-third, the residential sector for about one-fifth, and the commercial sector for the remainder. Industry's emissions derive from a broad mix of fossil-origin energy, including electricity, petroleum, natural gas, and coal. Not surprisingly, the transportation sector emits carbon dioxide mostly via the consumption of petroleum (especially motor gasoline, distillate fuels such as diesel, and jet fuel). Residential- and commercial-sector emissions are owed mostly to the use of electricity and natural gas.

The U.S. Energy Outlook

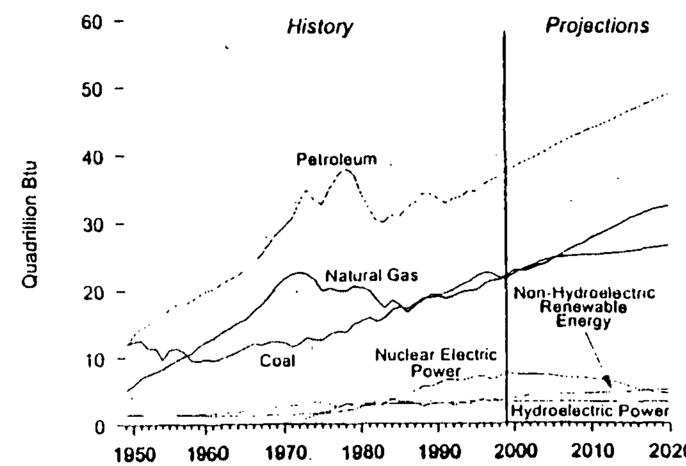
Future patterns of energy production, use, and consequences in the United States are, of course, purely speculative. But educated guesses can be made by means of sophisticated computer models, such as the Energy Information Administration's National Energy Modeling System (NEMS). EIA's current projections are published in its *Annual Energy Outlook 2000* (*AEO 2000*) and extend through 2020. Although emphatically not to be taken as predictions—no existing or imaginable model pretends to be able to foresee critical but unexpected events, such as the 1973 oil embargo—the projections can sketch a plausible general picture of future developments given known trends in technology and demographics and current laws and regulations.

The projections in *AEO 2000* suggest our near-term energy future will be one of more: consumption, production, imports, and emissions. Real energy prices are expected either to increase slowly (petroleum and natural gas) or to decline (coal and electricity). These circumstances will encourage greater consumption (Figure 34), and *AEO 2000* projects U.S. total consumption to reach 121 quadrillion Btu in 2020, 27 percent higher than in 1998. Consumption rises in all sectors, but growth is especially strong in transportation because of more travel and greater freight requirements.

Despite the general increase in energy consumption, efficiency gains and rising population keep per-capita use of energy roughly stable through 2020, according to the projections. Energy intensity, expressed as energy use per dollar of gross domestic product, has declined since 1970 and is expected to continue falling.

More energy consumption, of course, means more energy production—somewhere. Because the output of aging U.S. oil fields will continue to drop, rising demand for petroleum will have to be met by imports. The share of U.S. petroleum consumption met by net imports is projected to

Figure 34. Energy Consumption by Fuel, 1949-2020



rise from 52 percent in 1998 to 64 percent in 2020. Domestic natural gas production, on the other hand, increases 1.5 percent per year on average, an increase sufficient to meet most of the higher demand. Output from the Nation's vast coalfields likewise increases to meet rising domestic demand. Growth in production of energy from renewable sources is less than 1 percent per year, while output from nuclear power facilities declines significantly.

Unless policies to reduce emissions of carbon dioxide (such as those proposed under the 1997 Kyoto Protocol) are adopted, greater use of fossil fuels, slow market penetration by renewable energy sources, and less use of nuclear power will inevitably lead to higher emissions. *AEO 2000* projects U.S. energy-related carbon dioxide emissions to reach nearly 2 billion metric tons of carbon (7.3 billion tons of gas) in 2020, 33 percent more than in 1998.

What of our long-term energy future? That is even more speculative. Many would argue that the world is destined to move beyond fossil fuels eventually; if the threat of global climate change does not compel it, then exhausted supplies and rising prices may. The far future seems likely to belong to renewable sources of energy. Although the form they take may be radically different than in the past—solar hydrogen and advanced photovoltaics, perhaps, rather than fuelwood and dung—humankind's sources of energy thus will have come full circle.

Figure Source Notes

1. *Annual Energy Review 1999*, Appendix F, Tables F1a and F1b.
2. Ibid., Table 1.2.
3. Ibid., Tables 1.2 and 1.3.
4. Ibid., Table 1.1.
5. Ibid., Table 5.1.
6. Ibid., Table 2.1.
7. Ibid.
8. Ibid.
9. Ibid., Table 1.15.
10. Ibid., Table 2.9.
11. Ibid., Table 5.1.
12. Ibid., Table 5.2.
13. Ibid.
14. Ibid., Tables 5.12a and 5.12b.
15. Ibid., Table 5.15.
16. Ibid., Table 5.19.
17. Ibid., Table 6.1.
18. Ibid., Table 6.3.
19. Ibid., Table 6.4.
20. Ibid., Table 6.5.
21. Ibid., Table 7.2.
22. Ibid.
23. Ibid., Table 7.3.
24. Ibid., Table 8.2.
25. Ibid., Table 8.9.
26. Ibid., Table 8.3.
27. Ibid., Table 8.1.
28. Calculated from data in *Annual Energy Review 1999*, Tables 8.13 (residential electricity) and A6, 5.22 (all types of motor gasoline) and A3, and 6.9 (residential natural gas) and A4.
29. *Annual Energy Review 1999*, Table 9.1.
30. Ibid.
31. Ibid.
32. Ibid., Table 1.2.
33. Ibid., Table 12.1.
34. **History:** Energy Information Administration, *Annual Energy Review 1999*, Table 1.3. **Projections:** Energy Information Administration, *Annual Energy Outlook 2000*, Tables A1 and A18.

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Kelliher, Joseph

From: Kolevar, Kevin
Sent: Thursday, May 31, 2001 10:40 AM
To: Kelliher, Joseph; Hutto, Chase
Subject: NEP action plan

NEP Action Plan.doc

Kelliher, Joseph

rom: JWeisgal: :internet [

Sent: Wednesday, May 23, 2001 11:21 AM

To: Kelliher, Joseph

Cc: tdbonner@midamerican.com%internet

Subject: Geothermal recommendations

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See attached. Please feel free to call with any questions or comment

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CONCEPTS FOR AN EXECUTIVE ORDER

FOR GEOTHERMAL DEVELOPMENT ON FEDERAL PUBLIC LANDS

<u>POLICY</u> – Consistent with the National Energy Policy relating to all energy sources, and specifically to renewable sources, all federal agencies, under the lead of the Departments of Energy and Interior are directed, consistent with applicable law, to undertake appropriate actions to expedite the development and production of geothermal resources from federal lands and to facilitate the sale of electricity from geothermal sources into the energy market.

<u>SPECIFIC DIRECTIVES</u>

- It is a national priority, consistent with other laws, to develop and expand the use of geothermal energy resources on federal lands. Federal agencies including, but not limited to the Bureau of Land Management (BLM) and the U.S. Forest Service (USFS), involved in geothermal leasing, permitting or other reviews are directed to give geothermal energy projects expeditious and priority consideration and minimize impediments and unnecessary requirements upon geothermal operations;

- The Department of the Interior (DOI) is directed to review its regulations and existing legal authority to enhance BLM's authority under the Geothermal Steam Act to ensure timely decisions or actions involving geothermal leases and subsequent permitting or review, including actions taken by other agencies, and to establish specific goals and timeframes for completion of leasing, permitting and other actions;

- The DOI is directed to expeditiously review all moratoria and withdrawals of land preventing exploration and development in Known Geothermal Resource Areas, and where considerations of additional energy supply outweigh the original purposes of the moratoria or withdrawal, to modify any such order to permit consideration of development under applicable law;

- The DOI is directed that all active pending administrative appeals concerning geothermal energy development should be expedited, including the consideration of assumption of jurisdiction of such appeals by the Secretary in order to reach final decisions on such appeals;

- The BLM is directed to decide whether or not to issue leases or hold a competitive lease sale within 90 days for all pending lease applications;

- DOI is directed to examine whether a portion of the federal share from geothermal royalties should be set aside for Native American Tribes that demonstrate historical ties to the land or operate as local units of government and to take appropriate regulatory action or propose legislative amendments as it determines necessary;

- BLM is directed to work with the U.S. Geological Survey, DOE, and USFS to fund geophysical studies, including the drilling of temperature gradient core holes.

to help characterize new potential geothermal resources in order to define high potential areas that can be offered for competitive bidding;

- BLM is directed to review its geothermal lease management rule, guidelines and practices to ensure that they promote and facilitate development;

- Federal agencies, especially the power marketing administrations, are directed to consider purchasing geothermal energy as part of their "green" power promotion efforts, and DOD is directed to consider long-term geothermal contracts in order to promote new development; and

- DOI is directed to review geothermal leasing and regulations by other agencies (including DOD) and to report on actions that could be taken to promote geothermal development and ensure uniform lease terms, administration and royalty policies;

- The Department of Energy is directed to establish a National Geothermal Coordinating Committee (as recommended by the February 28, 2001 NREL Report) to facilitate agency actions supporting and expediting the expanded production or energy from geothermal resources; and

- The Department of the Treasury is directed, in cooperation with the Department of Energy, to consider expanding the production tax credit to geothermal energy as part of its deliberations implementing the tax recommendations of the NEPDG.

SR/OIAF/2001-01

The Transition to Ultra-Low-Sulfur Diesel Fuel: Effects on Prices and Supply

May 2001

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

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Preface

In December 2000 the U.S. Environmental Protection Agency (EPA) issued a final rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements. The purpose of the rulemaking is to reduce emissions of nitrogen oxides and particulate matter from heavy-duty highway engines and vehicles that use diesel fuel. The rulemaking requires new emissions standards for heavy-duty highway vehicles that will take effect in model year 2007. "The pollution emitted by diesel engines contributes greatly to our nation's continuing air quality problems," the EPA noted in its regulatory announcement. "Even with more stringent heavy-duty highway engine standards set to take effect in 2004, these engines will continue to emit large amounts of oxides of nitrogen (NO_x) and particulate matter (PM), both of which contribute to serious public health problems in the United States."

While the review of this rule was underway, the Committee on Science of the U.S. House of Representatives asked the Energy Information Administration (EIA) to provide an analysis of the proposal (Appendix A). The Committee noted that the proposed rule would reduce the level of sulfur in highway diesel by 97 percent. "These deep sulfur reductions will require significant investment s that not all refiners may choose to make. As a result, diesel fuel supplies could be affected," the Committee's letter stated.

In response to the Committee's request, EIA undertook an analysis incorporating two different analytical approaches. Mid-term issues and trends are addressed through scenario analysis using EIA's National Energy Modeling System. In addition, refinery cost analysis addresses the uncertainty of supply in the short term. Discussion of the key issues and uncertainties related to the distribution of ultra-low-sulfur diesel is based on interviews with a number of pipeline carriers. As suggested by the Committee, most of the major assumptions in this report are consistent with those used by the EPA in its Regulatory Impact Analysis (RIA) of the Rule.

Within its Independent Expert Review Program, EIA arranged for leading experts in the fields of energy and economic analysis to review earlier versions of this analysis and provide comment. The reviewers provided comments on two draft versions of the report and discussed their comments in a joint meeting. All comments from the reviewers either have been incorporated or were thoroughly considered for incorporation. As is always the case when peer reviews are undertaken, not all the reviewers may be in agreement with all the methodology, inputs, and conclusions of the final report. The contents of the report are solely the responsibility of EIA. The assistance of the following reviewers in preparing the report is gratefully acknowledged:

Raymond E. Ory
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The legislation that established EIA in 1977 vested the organization with an element of statutory independence. EIA does not take positions on policy questions. It is the responsibility of EIA to provide timely, high-quality information and to perform objective, credible analyses in support of the deliberations of both public and private decisionmakers. The information contained herein should be attributed to the Energy Information Administration and should not be construed as advocating or reflecting any policy position of the U.S. Department of Energy or any other organization.

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Executive Summary

This study was undertaken at the request of the Committee on Science, U.S. House of Representatives. The Committee asked the Energy Information Administration (EIA) to provide an analysis of the Final Rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, which was signed by President Clinton in December 2000.[1]

The purpose of the rulemaking is to reduce emissions of nitrogen oxides (NO_x) and particulate matter (PM) from heavy-duty highway engines and vehicles that use diesel fuel. The new rule requires refiners and importers to produce highway diesel meeting a 15 parts per million (ppm) maximum requirement, starting June 1, 2006; however, pipelines are expected to require refiners to provide diesel fuel with an even lower sulfur content, somewhat below 10 ppm, in order to compensate for contamination from higher sulfur products in the system, and to provide a tolerance for testing. Diesel meeting the new specification will be required at terminals by July 15, 2006, and at retail stations and wholesalers by September 1, 2006. Under a "temporary compliance option" (phase-in), up to 20 percent of highway diesel fuel produced may continue to meet the current 500 ppm sulfur limit through May 2010; the remaining 80 percent of the highway diesel fuel produced must meet the new 15 ppm maximum.

The purpose of this study is to assess the possible impact of the new sulfur requirement on the diesel fuel market. The study discusses the implications of the new regulations for vehicle fuel efficiency and examines the technology, production, distribution, and cost implications of supplying diesel fuel to meet the new standards. In order to address both the short-term and mid-term supply issues identified by the Committee on Science, this analysis incorporates two different analytical approaches. Refinery cost analysis addresses the uncertainty of supply in the short term, during the transition to ultra-low-sulfur diesel fuel (ULSD) in 2006. Mid-term issues and trends (2007 through 2015) are addressed through scenario analysis using EIA's National Energy Modeling System (NEMS). The Committee on Science requested that these analyses use assumptions consistent with the Regulatory Impact Analysis published by the U.S. Environmental Protection Agency (EPA). Discussion of the key issues and uncertainties related to the distribution of ULSD is based on interviews with a number of pipeline carriers.

Although highway-grade diesel is the second most consumed petroleum product, gasoline is the most important product by far. In 1999 highway diesel accounted for 12 percent of total petroleum consumption and gasoline 43 percent.[2] Consumption of highway-grade diesel (500 ppm) accounted for 68 percent of the distillate fuel market in 1999, although 9 percent went to non-road (rail, farming, industry) and home heating uses.[3] Higher sulfur distillate (more than 500 ppm sulfur), used exclusively for non-road and home heating needs, accounted for the other 2 percent of the distillate market.

Assessment of Short-Term Effects of the Rule

Whether there will be adequate supply of diesel fuel as the new standard becomes effective in June 2006 is one of the key questions raised by the House Committee on Science in the request for analysis. To assess this possibility, cost increases for individual refineries to produce ULSD were estimated, the cost increases were arrayed from smallest to largest, and the resulting cost curves were matched against projected demand and imports. The cost curves reflect investment requirements and operating costs for refineries in Petroleum Administration for Defense Districts (PADDs) I through IV.[4] ULSD production costs were estimated for different groups of refineries based on size, sulfur content of feeds, fraction of cracked stocks in the feed,[5] boiling range of the feed, and fraction of highway diesel produced. Unlike ULSD analyses conducted by the EPA and others, the cost curves relied on proprietary stream data collected by

[1] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Parts 69, 80, and 86 (January 18, 2001).

[2] Energy Information Administration, *Petroleum Supply Annual 1999*, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), Table 3

[3] Energy Information Administration, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0525(99) (Washington, DC, September 2000), Tables 19-23.

[4] PADD V was not included in this analysis, because supply concerns are less of an issue in the transition period, and the requirement for California Air Resources Board diesel makes the PADD V market different from those in PADDs I-IV.

[5] Cracked stocks are previously processed streams that are more difficult to treat

EIA.[6] The capital and operating costs for the different groups were developed for EIA by the staff of the National Energy Technology Laboratory (NETL), consistent with the EPA analysis. Return on investment was assumed to be 5.2 percent after taxes, consistent with the EPA's assumption of a 7-percent before-tax return on investment. Costs were not adjusted to take sulfur credit trading into account, because of the uncertainty about whether trading would occur and the value of the credits. If credit trading occurred, costs could be reduced.

Cost representations of desulfurization units were used to develop four sets of cost curves, based on four different investment rationales (Table ES1). Within a given supply curve, the relative costs of different groups of refineries provide an indicator of possible supply shortfalls at the beginning of the ULSD requirement in the summer of 2006. Some refiners may be able to produce ULSD at a cost of about 2.5 cents per gallon; however, at the volumes needed to meet demand, costs are estimated at 5.4 to 6.8 cents per gallon,[7] and they could be higher if supply falls short of demand and consumers bid up the price. The behavior of refiners will be influenced by their expectation of what others will do and is therefore subject to considerable uncertainty.

The four refinery investment scenarios have progressively more volume and are defined as follows:

- The **Competitive Investment** scenario includes only those refiners that are very likely to prepare to produce ULSD in 2006. They currently hold market share and are estimated to be able to produce ULSD at a competitive cost. Refiners with highway diesel as a relatively low fraction of their distillate production are assumed to abandon the market unless their cost per unit of production is competitive at current highway diesel production levels.

- In the **Cautious Expansion** scenario, current producers with competitive cost structures for ULSD production and high fractions of highway diesel production (greater than 70 percent) are assumed to maintain current production levels and, possibly, to push production of ULSD toward 100 percent of their distillate production if only minor increases in per-unit production costs occur for the increased volume.

- The **Moderate New Market Entry** scenario assumes that a selective number of refineries currently producing little or no highway diesel will enter the ULSD market. The underlying premise is that a limited number of companies would think that they would be able to gain market share without depressing margins to the extent of undercutting profits.

- The **Assertive Investment** scenario assumes that a larger number of refiners would make the requisite investments to either maintain or gain share in the highway diesel market. In this scenario, refiners would believe that most of their competitors were overly cautious, and that they could succeed by taking a contrary strategy (which in reality would be adopted by far more refiners than anticipated).

As a result of distribution limitations and non-road uses, the amount of ULSD actually needed to balance demand in 2006 is highly uncertain. Accordingly, a range of demand estimates was developed to account for some of the uncertainty (Table ES2 and Figure ES1). The Small Refiner and Temporary Compliance Options demand estimate was calculated as 80 percent of the estimated demand for transportation distillate for both highway and non-road uses in PADDs I-IV in 2006 (excluding production by small refineries, which are allowed to request waivers to delay production until 2010), representing the EPA's requirement to produce 80 percent ULSD after the regulation takes effect. The Small Refiner and Temporary Compliance Options with Imports

Table ES1. Short-Term Scenarios

Scenario	Number of Refineries Producing ULSD	Characteristics
(1) Competitive Investment	66	Current low-sulfur diesel producers maintain market share. Low-fraction producers drop out.
(2) Cautious Expansion	66	Some low-sulfur diesel producers in Scenario 1 expand production.
(3) Moderate New Market Entry	67	One refinery not currently producing low-sulfur diesel enters the ULSD market. Nine other producers in Scenario 2 expand production.
(4) Assertive Investment	74	A larger number of refineries not currently producing low-sulfur diesel enter the ULSD market. Some others expand production.

Notes: Current low-sulfur diesel contains 500 ppm sulfur. ULSD contains 7 ppm sulfur to compensate for contamination and to provide a tolerance for testing.

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

[6]The EPA used EIA data on refinery capacity and diesel production in its refinery-by-refiney analysis.

[7]These are marginal costs on the industry supply curve, based on average refinery costs for producing ULSD. These cost estimates do not include additional costs for distribution, estimated at 1.1 cents per gallon in the mid-term analysis.

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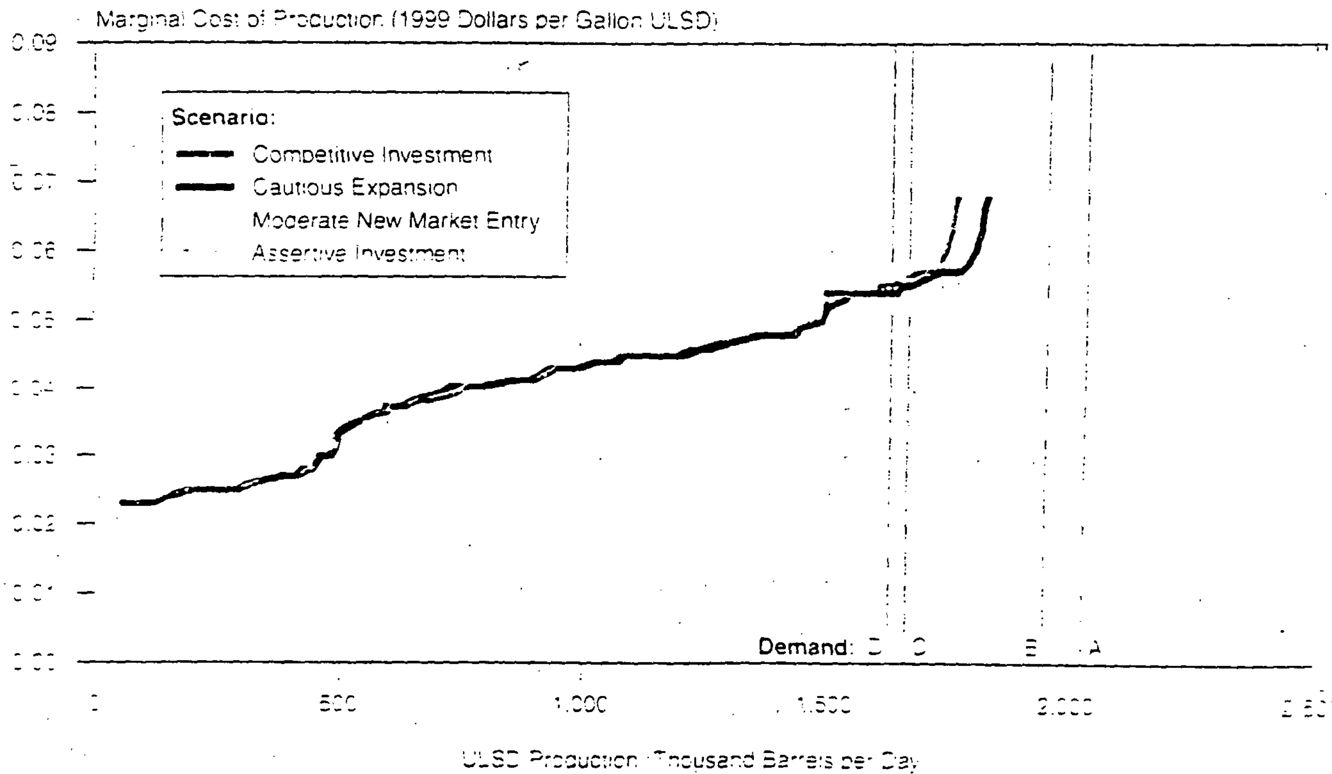
estimate assumes that imports from Canada and the Virgin Islands will continue at historical levels (Demand B, which matches the demand projection in the mid-term analysis described in Chapter 6). The Highway Use Only, Small Refiner and Temporary Compliance Options with Imports estimate (Demand C) assumes that ULSD will be used only to meet highway transportation demand, that the temporary compliance option will further reduce this demand by 20 percent, and that imports will remain at historical levels. Finally, the Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports estimate (Demand D) assumes a higher level of ULSD imports.[8]

Table ES2. Short-Term Demand Estimates, 2006

Estimate	Demand Level (Thousand Barrels per Day)	Characteristics
Demand A: Small Refiner and Temporary Compliance Options	2,026	76 percent of transportation demand.
Demand B: Small Refiner and Temporary Compliance Options with Imports	1,946	Demand estimate A, less projected imports from Canada and the U.S. Virgin Islands.
Demand C: Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,662	65 percent of transportation demand, less projected imports from Canada and the U.S. Virgin Islands.
Demand D: Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,625	Demand estimate C, less higher projected imports

Source: National Energy Modeling System, run DSU7INV.D043001A.

Figure ES1. ULSD Cost Curve Scenarios with 2006 Demand Estimates



Demand A: Small Refiner and Temporary Compliance Options
Demand B: Small Refiner and Temporary Compliance Options with Imports
Demand C: Highway Use Only, Small Refiner and Temporary Compliance Options with Imports
Demand D: Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling System, run DSU7INV.D043001A.

[8] Additional demand estimates are analyzed in Chapter 5.

The combined cost curves for PADDs I-IV show that the total volume of ULSD production on the cost curves for the Competitive Investment and Cautious Expansion scenarios, production reaches the two lowest demand estimates, although at different costs (Figure ES1). In the Moderate New Market Entry scenario, production just reaches the Small Refiner and Temporary Compliance Options with Imports estimate. In the Assertive Investment scenario, production just reaches the Small Refiner and Temporary Compliance Options estimate.

The largest shortfall—estimated at 264,000 barrels per day relative to the Small Refiner and Temporary Compliance Options demand estimate (Demand A, the highest demand estimate in Table ES2)—occurs in the Competitive Investment scenario (which assumes the most cautious investment strategy and has the lowest production estimate). The largest surplus—517,000 barrels per day relative to the Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports estimate (the lowest demand estimate)—occurs in the Assertive Investment scenario (which assumes the most aggressive investment strategy and has the highest production estimate).

With the Highway Use Only, Small Refiner and Temporary Compliance Options with Imports demand estimate (Demand C), all the production scenarios project sufficient supply (at least in the aggregate). For the Small Refiner and Temporary Compliance Options with Imports demand estimate (Demand B), the Moderate New Market Entry and Assertive Investment production scenarios provide supplies that are higher than demand by 197,000 barrels per day and 6,000 barrels per day, respectively. Supplies in the Competitive Investment and Cautious Expansion scenarios fall short of Demand B by 184,000 and 123,000 barrels per day, respectively. For the Small Refiner and Temporary Compliance Options demand estimate (Demand A), only the Assertive Investment production scenario provides sufficient supply.

Two sensitivity cases were used to examine the effects of assumptions about hydrotreater capital costs and about return on investment. The capital costs assumed in the initial set of four scenarios are similar to those used in the EPA analysis. When the capital costs for hydrotreater units are assumed to be about 40 percent higher than assumed in the initial set of scenarios, production of ULSD is projected to be 25,000 to 55,000 barrels per day lower, and the production costs are projected to be from 0.5 to 1.1 cents per gallon higher. When a 10-percent return on investment is assumed, as compared with 5.2 percent assumed in the initial set of scenarios, production is projected to be 40,000 to 66,000 barrels per day lower and costs 0.8 to 1.2 cents per gallon higher. Because of the reduced volumes, estimated production levels in the Moderate New Market Entry Scenario fall short of the demand level projected in the Small Refiner and Temporary Compliance Options with Imports estimate in both the higher capital cost and higher required return on investment sensitivity cases.

The scenarios indicate the possibility of a tight diesel market when the ULSD Rule is implemented. Supply scenarios that assume more cautious investment indicate inadequate supply compared with the demand levels projected in the *Annual Energy Outlook 2001*. Only more aggressive investment scenarios or lower demand scenarios show adequate supply to meet estimated demand. Furthermore, this analysis compares supply and demand at a very aggregate level. Maintaining a balance of supply and demand across regions and throughout the distribution system could be even more difficult.

If supplies fell short of demand, sharp price increases would likely occur to balance supply and demand. Sharply higher prices would curtail demand for diesel fuel. Truckers would reduce consumption to the extent possible and try to pass higher fuel costs on to customers, who would then look for alternative means to transport goods. In this situation refiners would attempt to maximize ULSD production. Some additional production may be possible by, for example, shifting some non-road distillate or jet fuel streams into ULSD. Additional imports of ULSD or jet fuel could be forthcoming if there were large price differentials between markets.

In 2006, little ULSD will actually be needed, because few new vehicles requiring ULSD will be on the road by then. If it becomes apparent that there will be inadequate supply, or if distillate markets are tight, the EPA could temporarily reduce the required proportion of ULSD production, which could make additional diesel supplies available. However, a temporary reduction would reduce the availability of ULSD supplies for new vehicles. In its final rulemaking the EPA required refiners and importers to submit a variety of reports to ensure a smooth transition, and the agency plans to establish an advisory panel to look at issues of diesel supply and monitor the progress of related technologies.

Assessment of Mid-Term Effects of the Rule

The mid-term analysis for this study was performed using the NEMS Petroleum Market Module (PMM) to assess the impact of new requirements for ULSD in the years 2007 through 2015. The PMM represents domestic refinery operations and the marketing of petroleum products to consumption regions. Refining operations are represented by a three-region linear programming formulation of the five PADDs. PADDs I (East Coast) and V (West Coast) are treated as single regions, and

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PADDs II (Midwest), III (Gulf Coast), and IV (Rocky Mountains) are aggregated into one region. Each region is considered as a single firm, for which more than 80 distinct refinery processes are modeled. Refining capacity is allowed to expand in each region.

Unlike previous ULSD analyses, the PMM provides multi-year scenarios. These scenarios reflect market prices rather than average costs and implicitly include investment and import decisions. In contrast to the cost curves used in the short-term analysis, the NEMS projections reflect equilibrium market prices. That is, the results of the PMM scenarios assume that, in the long run, refiners will increase supply to meet demand. As a result, the NEMS analysis reflects more aggressive investment behavior than that portrayed for individual refiners in the short-term analysis.

The PMM was used to develop a ULSD Regulation case based on the provisions of the EPA's final ULSD Rule. A Severe case was developed to combine five sensitivity cases associated with greater uncertainty in industry operations and costs.[9] Finally, a No Imports case and a 10% Return on Investment case were developed.

In the **Regulation case**, highway diesel at the refinery gate is assumed to contain a maximum of 7 ppm sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel somewhat below 10 ppm in order to allow for contamination during the distribution process. Revamping existing units to produce ULSD is assumed to be undertaken by 80 percent of refineries, while 20 percent build new units. The amount of ULSD that is to be downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to total 4.4 percent. The energy content of the ULSD is assumed to decline by 0.5 percent, because undercutting and severe desulfurization will result in a lighter stream composition than 500 ppm diesel. The Rule is assumed to result in no loss in vehicle fuel efficiency. The actual after-tax return on investment is assumed to be 5.2 percent, which is equivalent to a 7-percent before-tax return on investment. As suggested by the Committee, the major assumptions in this case are consistent with those used by the EPA in its Regulatory Impact Analysis (RIA) of the Rule.[10]

The **Severe case** combines five sensitivities at variance with the above assumptions. In the "2/3 Revamp" sensitivity case, two-thirds of upgrades at refineries are assumed to be accomplished by retrofitting existing equipment and one-third by construction of all new units, consistent with the results of the individual refinery analysis. In the "10% Downgrade" case, 10 percent of the 15 ppm diesel produced is assumed to be downgraded to a lower value product because of contamination with higher sulfur products in the distribution system. In the "4% Efficiency Loss" case it is assumed that manufacturers will meet the emissions requirements of the ULSD Rule by installing after-treatment technology on new vehicles beginning in 2010, which would result in a 4-percent loss of fuel efficiency that is phased out as new technology emerges. In the "1.8% Energy Loss" case, a greater loss of energy content is assumed than in the Regulation case. In the "Higher Capital Cost" case, the capital costs of the hydrotreaters are 24 percent higher and 33 percent higher than in the Regulation case, based on a review of the most recent industry cost data.

The **No Imports case** assumes that foreign imports of ULSD will not be available. This assumption was not included in the Severe case because it was deemed to be less likely. Foreign supplies should be available from Canadian refiners, who likely will move to the U.S. standard at the same time as the United States, and from a large refinery in the U.S. Virgin Islands that is jointly owned by Armada Hess and Venezuela's national oil company, PdVSA. Both owners of the Virgin Islands plant see the United States as a strategic market. The greatest uncertainty for import availability is likely to occur in the early years of the program, because foreign refiners may delay investment until the market outlook for ULSD is more certain.

The **10% Return on Investment** case uses the after-tax rate of return assumed in most other studies, which is higher than the 5.2-percent after-tax rate used in the Regulation case and in the other sensitivity cases in this study, consistent with the EPA's assumption. At a rate of return less than 10 percent, investors may hesitate to put money into the refinery industry, especially for equipment designed for a new product.

In the Regulation case, the marginal annual pump price for ULSD is projected to range from 6.5 to 7.2 cents per gallon between 2007 and 2011 (Table ES3 and Figure ES2).[11] The peak differential is projected to occur in 2011, when oil refiners must produce 100 percent ULSD. In absolute terms, real marginal prices range from $1.29 to $1.35 per gallon in the Regulation and Severe cases from 2007 to 2011.[12] Refiners are projected to invest $6.3 to $9.3 billion to meet full compliance with the ULSD Rule through 2011.

[9] Results for the five sensitivity cases are provided in Chapter 6 and Appendix E

[10] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements*, EPA420-R-00-026 (Washington, DC, December 2000).

[11] Analysis of 2006 is discussed above. As a partial year, 2006 is not included in the equilibrium analysis

[12] These cases are based on variations from a reference case similar to that in EIA's *Annual Energy Outlook 2001*

After 2011, the first full year of 100 percent ULSD, the projected differential of marginal prices is generally expected to decline, because of lower distribution and capital investment costs. About 0.7 cents of the projected decline results from using the EPA's assumption that the additional capital investments for distribution and storage of a second highway diesel fuel will be fully amortized during the transition period. The remainder of the drop in the post-2011 differential occurs because refineries are assumed to have completed the upgrades necessary for full compliance, to be making additional investment only to meet incremental demand, to be replacing and upgrading existing equipment, and to be making incremental operating improvements that make ULSD production less challenging. A similar decline in the price differential also occurs in all the sensitivity cases.

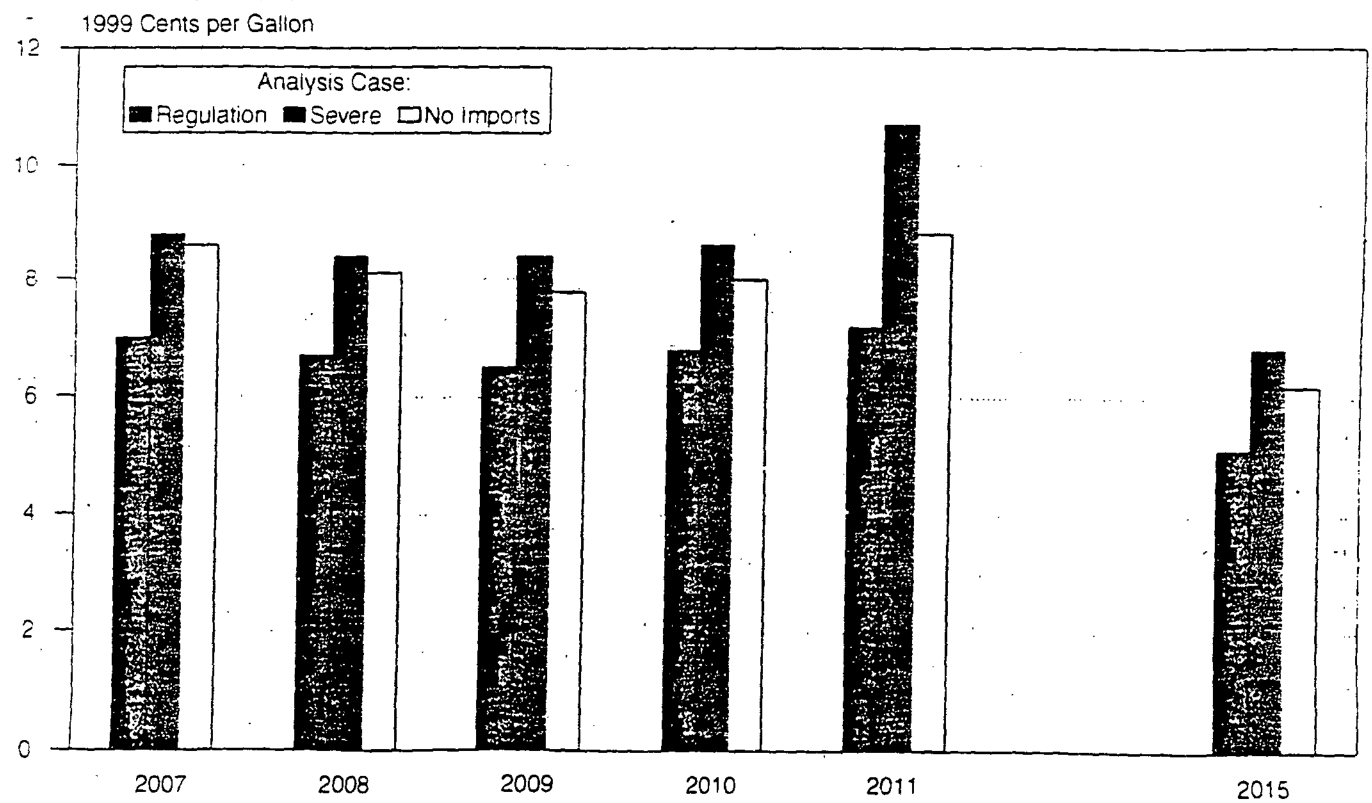
Through 2010, the Regulation case projections for highway diesel consumption exceed the reference case levels

Table ES3. Variations from Reference Case Projections in the Regulation and Sensitivity Analysis Cases, 2007-2015

Analysis Case	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
Difference Between End-Use Prices of ULSD and 500 ppm Diesel (1999 Cents per Gallon)								
Regulation	7.0	6.7	6.5	6.8	7.2	5.1	6.8	5.4
Severe	8.8	8.4	8.4	8.6	10.7	6.8	8.6	7.4
No Imports	8.6	8.1	7.8	8.0	8.8	6.2	8.1	6.8
Total Highway Diesel Fuel Consumption (Thousand Barrels per Day)								
Regulation	10	10	8	8	83	85	9	83
Severe	41	40	39	57	355	374	44	366
No Imports	10	9	7	7	81	83	8	81
Total Imports of Highway Diesel Fuel (Thousand Barrels per Day)								
Regulation	-36	-1	-1	0	0	0	-10	0
Severe	-36	-1	-1	0	0	0	-10	0
No Imports	-120	-125	-125	-125	-125	-125	-124	-125

Source: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7ALL.D050101A, and DSUIMP0.D043001A.

Figure ES2. Difference Between End-Use Prices of ULSD and 500 ppm Diesel in the Reference Case, 2007-2015



Source: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7ALL.D050101A, and DSUIMP0.D043001A.

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by up to 10,000 barrels per day, which can be attributed to the assumption of 0.5-percent loss in energy content. In 2011 the differential in consumption increases to 83,000 barrels per day, because ULSD contaminated in the distribution system can no longer be downgraded to 500 ppm highway diesel, and refiners must therefore make more ULSD.

In the Severe case, up to 57,000 barrels per day of additional highway diesel is projected to be consumed between 2007 and 2010, and an average of 366,000 barrels per day of additional consumption is projected between 2011 and 2015. The ULSD Rule by itself accounts for an average of 9,000 barrels per day of the additional consumption through 2010 and an average of 83,000 barrels per day after 2010. The combined effects of the 2/3 Revamp, 10% Downgrade, 4% Efficiency Loss, 1.8% Energy Loss, and Higher Capital Cost cases raise consumption beyond that in the Regulation case by at least 30,000 barrels per day through 2010, primarily because of energy losses and higher capital cost, and by an average of 283,000 barrels per day after 2010 because of energy losses, downgrading, and efficiency losses. The higher downgrade assumption accounts for about 210,000 barrels of the additional demand after 2010. ULSD-related investments in the Severe case are projected to total $9.3 billion through 2011, $3 billion more than in the Regulation case. Higher demand in the Severe case generally results in marginal prices 1.7 to 1.9 cents per gallon above those in the Regulation case, although costs range up to 3.5 cents per gallon higher in 2011.

The No Imports case explores the impact of the ULSD Rule by assuming that foreign imports will not be available to meet the new sulfur standard. In the Regulation case, projected imports of highway diesel are lower than in the reference case in the first few years, because foreign refiners are expected to be more hesitant to invest to meet a U.S. regulation. The No Imports case assumes that no imports of ULSD are available, and that imports of highway diesel are reduced by 120,000 to 125,000 barrels per day between 2007 and 2015, relative to the reference case. The lack of imports means that domestic refineries must produce more ULSD. The requirement for more production results in marginal prices 1.1 to 1.6 cents per gallon higher than in the Regulation case. The higher prices in the No Imports case result in a slight dampening of demand compared with the Regulation case.

Because the Regulation case assumes a 5.2-percent after-tax return on investment, the 10% Return on Investment case must be compared with an alternative base case that assumes the same return on investment. The resulting price differentials range from 7.5 to 8.0 cents per gallon between 2007 and 2011 and are 0.9 cents per gallon higher on average than when the 5.2-percent after-tax rate is assumed.

Differences between regional end-use prices in the analysis cases relative to those in the reference case reflect variations in the marginal costs of producing ULSD between regions. The cost curve analysis described in Chapter 5 indicates that PADD IV, which is made up of relatively small refineries, can be expected to be the highest cost region. The relatively high cost in PADD IV is obscured in the mid-term analysis (Chapter 6), because PADD IV is aggregated with both PADD II and the largest and lowest cost refining region, PADD III. In the transition years of the Regulation case, regional refining costs range from an average of 4.8 to 5.3 cents per gallon. PADD I is the highest cost region, PADD V is the lowest cost region, and PADDs II-IV (and average U.S.) costs fall in between. Average marginal refining costs generally narrow by about 0.5 cents per gallon in the post-2010 period, as refineries make incremental improvements that allow them to produce ULSD more efficiently.

Additional Uncertainties

Uncertainties about the pace of engine, refinery, and pipeline testing technology development; the availability of personnel, thick-walled reactors, and reciprocating compressors; the behavior of ULSD in the oil pipeline system; and cost recovery by oil pipelines further cloud the outlook for the transition to very low levels of sulfur in diesel fuel. The new ULSD Rule requires not only that the sulfur content of transportation diesel fuel oil produced by domestic refineries be drastically reduced by 2007, but also that emission controls on heavy-duty diesel engines be imposed to reduce emissions of NO_x, PM, and hydrocarbons (HC).

Historically, engine manufactures have met new emissions standards through modifications to engine design. To meet the 2007 standard, manufacturers will have to rely heavily on component and system development by emission control equipment manufacturers. In particular, engine manufacturers must implement an exhaust after-treatment catalyst technology to control NO_x emissions. Currently, the EPA expects NO_x adsorbers to be the most likely emission control technology applied by the industry. Using current catalyst technology, the fuel-rich cycle could reduce fuel efficiency by 4 percent. To date, no NO_x adsorber system has proven feasible. Although NO_x adsorbers have demonstrated compliance using ULSD (7 ppm), the systems show losses in conversion efficiency after 2,000 miles of operation. In order to meet the 2007 emission standards for heavy-duty diesel engines, conversion efficiencies must be improved, and exhaust gas recirculation equipment must be optimized. The considerable time available for research and development, however, may provide government and industry ample time to resolve the fuel efficiency loss issues associated with advanced emission control technologies.

Beyond traditional hydrotreating to remove sulfur from diesel streams, new technologies are under development that could reduce the cost of desulfurization. They include sulfur adsorption, biodesulfurization, sulfur oxidation, gas-to-liquids, and biodiesel. Each of these technologies is in the first stages of commercialization. Although they are being spurred by the EPA Rule, it is uncertain whether any of the new technologies will make a significant contribution to meeting the requirements of the ULSD Rule in 2006, although they may have some impact later in the decade.

Before the ULSD Rule takes effect in 2006, sulfur testing methods must also be improved. The designated method, ASTM 6428-99, 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. Because the diesel methodology has not yet been developed for the designated method, it has not yet been tested by multiple laboratories. There is also no readily available and appropriate test for sulfur that will permit the precise cuts between batches that will be required in handling ULSD. 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 in as little as a minute's time. However, current instruments for testing sulfur do not have adequate sensitivity, accuracy, or speed for the job. Current machines require 5 to 10 minutes to complete one analysis of a passing product stream—far too long to permit a pipeline operator to make a correctional response if off-specification material is detected in a batch of ULSD.

The deployment of diesel desulfurization technologies will hinge not only on the ability and willingness of refiners to invest and the timing of investment and permitting but also on the ability of manufacturers to provide units for all U.S. refineries at once, and the availability of engineering and construction resources. In addition to providing diesel hydrotreaters, the same contractors will be designing and building gasoline desulfurization units for the Tier 2 gasoline sulfur reduction requirements that will be phased in between 2004 and 2007. The EPA's breakout of the expected startup of gasoline and diesel desulfurization units reflects an overlap of 26 gasoline units and 63 diesel units in 2006, more than any other year except 2004. The EPA estimates that 30 percent more workers will be required for the gasoline and diesel programs together than for the gasoline program alone. If thick-walled reactors are required for deep hydrotreating, delivery lead times will be longer, because only one or two U.S. companies produce thick-walled reactors. Another type of critical equipment is reciprocating compressors. Two reciprocating compressors will be required for each diesel desulfurization project. Reciprocating compressors will also be required for gasoline desulfurization projects. Excluding the former Soviet Union, there are only five manufacturers of reciprocating compressors in the world.

The exact sulfur level at which refineries will be required to produce ULSD is not certain, because there is no experience with distributing ULSD in a non-dedicated or common transportation system. Residual sulfur from high-sulfur material could contaminate subsequent pipeline material beyond the interface between the two products. Recently, Buckeye Pipe Line conducted a test of possible sulfur contamination from one product batch to another. Buckeye carefully measured the sulfur content in batches of highway diesel fuel following a batch of high-sulfur diesel fuel and found that the sulfur content of the second batch of highway diesel fuel increased. Exact sulfur levels have implications for the amount of material downgraded during pipeline and terminal operations.

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; however, oil pipelines will incur large incremental capital and operating costs in distributing the new diesel fuel. If an oil pipeline carrier is operating under the Federal Energy Regulatory Commission's commonly approved index method and applies its existing tariff rate to ULSD, there will be no basis for the carrier to recover its incremental costs in the approved rate. A carrier might file a new tariff rate expressly covering ULSD.

Comparison with Other Studies

Earlier studies related to ULSD supply and costs included analyses by the U.S. Environmental Protection Agency (EPA), Mathpro, the National Petroleum Council (NPC), Charles River and Associates with Baker and O'Brien, EnSys Energy & Systems, Inc., and Argonne National Laboratory (ANL). The studies were based on two general types of methodologies: a linear programming (LP) approach used by Mathpro, NPC, EnSys, ANL, and EIA; and a refinery-by-refinery approach used by Charles River, EPA, and EIA.

Cost estimates from the different studies are not easy to compare, because differences in estimation methodologies make them conceptually different. Both average and marginal costs can be based on LP models that operate as a single firm, or estimated from analysis of individual refineries. In general, marginal cost estimates that represent the cost of the last barrel of required supply can be seen as estimates of market prices. Average cost estimates usually reflect refinery investment, but they are not good estimates of market prices. Much of the variation in investment and cost estimates reflects

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different assumptions about the cost of technologies; unit size; contingency factors; the extent to which refiners will modify existing equipment or build entirely new hydrotreaters; the cost and quantity of additional hydrogen required; the extent to which some refineries may reduce highway diesel production; and the amount of highway diesel downgraded due to fuel contamination during distribution. Nevertheless, the studies using LP models reported cost increases ranging from 4.0 to 10.7 cents per gallon, excluding distribution costs and taxes. The marginal refinery gate prices reported in this study for the post-2006 period, which exclude distribution costs and taxes, range from 4.7 to 9.2 cents per gallon.

Likewise, the costs derived from refinery-by-refinery analysis included average costs for the industry and average costs for the marginal firm, different estimates of the penetration of ULSD, different consumption estimates, different assumptions about the cost of technologies, different assumptions about the extent to which refiners will modify existing equipment or build entirely new hydrotreaters, different assumptions about the cost and quantity of additional hydrogen required, and different regions. The range of estimated cost increases reported in the studies using refinery-by-refinery analysis was 4.1 to 6.8 cents per gallon. This study's range for the 2006 analysis is at the higher end, because it leaves out the lower cost PADD V, is based on marginal industry costs rather than average refinery costs, and has 63 percent of refineries revamping their hydrotreaters, as compared with 80 percent in the studies with lower cost estimates.

1. Background and Methodology

Introduction

This study was undertaken at the request of the Committee on Science, U.S. House of Representatives. The Committee asked the Energy Information Administration (EIA) to provide an analysis of the Final Rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, which was signed by President Clinton in December 2000.[1] Along with all other regulations finalized at the end of the Clinton Administration, the Rule underwent a 60-day review by the Bush Administration. On February 28, 2001, the Administrator of the U.S. Environmental Protection Agency (EPA), Christine Todd Whitman, gave her approval to move forward with the new rule, citing the great benefits to public health and the environment.[2]

The purpose of the rulemaking is to reduce emissions of nitrogen oxides (NO_x) and particulate matter (PM) from heavy-duty highway engines and vehicles that use diesel fuel. The rulemaking requires new emissions standards for heavy-duty highway vehicles that will take effect in model year 2007. Because the advanced emission control devices that will be required to meet the 2007 emissions standards are damaged by sulfur, and because the 2007 model year begins September 1, 2006, the rulemaking also requires the sulfur content of highway diesel to be substantially reduced by mid-2006.

The purpose of this study is to assess the possible impact of the new sulfur requirement on the diesel fuel market. The study does not address the impact of the rulemaking on vehicle emissions or public health.[3] This study discusses the implications of the new regulations for vehicle fuel efficiency and examines the technology, production, distribution, and cost implications of supplying diesel fuel to meet the new standards.

A summary of the new sulfur requirement, the analysis issues identified by the Committee on Science, and the methodology of the report are provided in the remainder of this chapter. Chapter 2 describes emission control technologies for heavy-duty diesel engines, their effects on fuel efficiency, and expected costs. Chapter 3 discusses technologies for producing ultra-low-sulfur diesel fuel (ULSD) and the analysis approaches used in this study to assess their future costs. Chapter 4 discusses the impact of the ULSD Rule on oil pipeline operations. Chapter 5 addresses the issue of future supply of ULSD, particularly during the transition period in 2006, and the potential responses of refinery operators. Chapter 6 summarizes mid-term projections (2007 through 2015) for diesel fuel prices, based on a range of assumptions in cases analyzed using EIA's National Energy Modeling System (NEMS). A comparison of the assumptions and estimates from this study with those from other analyses is provided in Chapter 7.

Summary of the Final ULSD Rule

The new ULSD Rule requires refiners and importers to produce highway diesel meeting a 15 parts per million (ppm) maximum requirement starting June 1, 2006.[4] Pipeline operators are expected to require refiners to provide diesel fuel with even lower sulfur content (somewhat below 10 ppm) in order to compensate for possible contamination from higher sulfur products in the system and to provide a tolerance for testing. Diesel meeting the new specification will be required at terminals by July 15, 2006, and at retail stations and wholesalers by September 1, 2006. This time schedule is driven by the need to provide fuel for the 2007 model year diesel vehicles that will become available in September 2006. Under a "temporary compliance option" (phase-in), up to 20 percent of highway diesel fuel produced may continue to meet the current 500 ppm sulfur limit through May 2010. The remaining 80 percent of the highway diesel fuel produced must meet the new 15 ppm maximum.

The ULSD Rule provides for an averaging, banking, and trading (ABT) program. Refineries that produce more than 80 percent of their highway diesel to meet the 15 ppm limit can receive credits, which may be traded with other refineries within the same Petroleum Administration Defense District (PADD) that do not meet the 80-percent production requirement. Starting June 1, 2005, refineries can accrue credits for producing any

[1] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Parts 69, 80, and 86 (January 18, 2001).

[2] U.S. Environmental Protection Agency, "EPA Gives the Green Light on Diesel-Sulfur Rule," Press Release (February 28, 2001).

[3] Sources addressing the impact of the ULSD Rule on vehicle emissions and public health are included in the bibliography.

[4] The State of Alaska and the U.S. Territories have been exempted from the program.

volume of highway diesel that meets the 15 ppm limit.[5] The trading program will end on May 31, 2010, after which time all refineries must produce 100 percent of their highway diesel at a low enough sulfur level to ensure 15 ppm at retail. The ABT program will not include refineries in States that have State-approved diesel fuel programs, such as California, Hawaii, and Alaska.

The Rule includes provisions for refiners in a Geographical Phase-In Area (GPA) that includes Colorado, Idaho, Montana, New Mexico, North Dakota, Utah, Wyoming, and parts of Alaska. The highway diesel provisions in the GPA are linked to the Tier 2 gasoline program. While the rest of the country is required to average 30 ppm gasoline sulfur requirements by January 2006, refineries in the GPA are granted an additional year to meet this requirement. Under the highway diesel provisions, refineries in the GPA that meet the ULSD standard by June 1, 2006, for all their highway diesel may receive a 2-year extension on gasoline compliance to December 31, 2008. To receive the extension, the refinery must maintain production of 15 ppm highway diesel fuel that is at least 85 percent of its average 1998 and 1999 highway diesel production.

Hardship provisions are allowed for small refiners with up to 1,500 employees corporate-wide and that had a corporate crude oil capacity of 155,000 barrels or less per calendar day in 1999. The small refiner provisions include: (1) production of 500 ppm diesel fuel until May 31, 2010; (2) the ability to acquire credits for producing 15 ppm highway diesel prior to June 1, 2010; and (3) a 2-year extension of the refiner's applicable interim gasoline standards if all its highway diesel fuel is 15 ppm sulfur beginning June 1, 2006.

Summary of the Request for Analysis

In its July 2000 letter (see Appendix A), the Committee on Science requested that EIA undertake a study addressing the possible supply and cost implications of the diesel fuel regulations. The Committee specifically asked EIA to address the following production and supply issues related to the ULSD Rule:

- The potential impacts of the Rule on highway diesel fuel supply and on costs to end users of diesel fuel[6]
- The potential impacts of the diesel fuel regulation on other middle distillate products such as home heating oil, non-road diesel, and jet fuel
- The cost and availability of ULSD imports
- The impact of the Rule on refinery operations
- The impact of the Rule on fuel efficiency (related to engine after-treatment devices) and on diesel fuel demand
- The cost of current and future technologies that are expected to allow refineries to meet the new sulfur standard, and their costs
- The likelihood that the necessary technologies will be adequately deployed to meet the new standards.

The memorandum also identified a number of issues related to the distribution of ULSD that are addressed in the study, including:

- The effects of the ULSD Rule on the U.S. oil distribution system both during and after the phase-in period
- How the distribution system would handle the second highway diesel product during the phase-in period, the infrastructure and investments required, and how the investments might be recouped
- The extent to which fuel contamination might occur when ULSD is shipped in common pipelines with other, higher sulfur products
- The capability of current testing methods to measure sulfur at the 15 ppm level
- The operational changes required in the distribution system, and how they will affect consumer costs.

In a followup letter dated January 24, 2001, the Committee on Science modified its initial request to reflect provisions included in the EPA's final rule. The Committee directed EIA to reflect the assumptions used by the EPA, to the extent possible. Where EPA's assumptions diverge meaningfully from industry expectations, EIA was asked to provide a sensitivity analysis. The Committee noted several issues that might require sensitivity analysis, including:

- The difference in production of 7 ppm versus 10 ppm diesel fuel
- The energy content of ULSD
- Fuel efficiency losses associated with engine after-treatment devices
- Additional distribution costs.

[5]Credits for 15 ppm diesel fuel can be accrued before this date if the refiner can certify that the fuel is to be used in vehicles certified to meet the 2007 model year heavy-duty engine standards.

[6]The Committee also asked about several issues relevant to the proposed rule but not to the Final Rule: how potential supply might change if the effective date of the diesel regulation were later and did not overlap those for gasoline sulfur requirements, and how potential supply would change if the ULSD requirement were phased in.

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Background

The ULSD Rule represents a unique financial and logistical challenge to refiners and distributors, because it places an unprecedented low sulfur limit on a secondary product. Although highway-grade diesel, which is currently limited to 500 ppm sulfur, is the second most consumed petroleum product, gasoline is the most important product by far. In 1999, 500 ppm diesel accounted for 12 percent of total petroleum consumption while gasoline accounted for 43 percent.[7] The ULSD Rule comes less than a year after a new nationwide sulfur standard for gasoline was finalized by the EPA at an average 30 ppm.[8] Some concerns have been raised that resources may be both financially and physically challenged to meet both the gasoline and diesel sulfur standards.[9]

In February 2000, the EPA finalized a rule on Tier 2 vehicle emissions and gasoline sulfur standards. The sulfur content of gasoline across the country is to be phased down to 30 ppm on average between 2004 and 2007. Like the diesel sulfur standard, reduced sulfur gasoline is required in order to accommodate new emissions control technologies required for meeting tighter vehicle emissions standards. Gasoline produced by most refiners will be required to meet a corporate average sulfur content of 120 ppm in 2004 and 90 ppm in 2005, compared with a national average of around 340 ppm in 1998.[10] By 2006, most refiners must meet a refinery level annual average of 30 ppm with a maximum of 80 ppm in any gallon.

Refiners producing most of their gasoline for the Geographical Phase-In Area (GPA), generally encompassing the Rocky Mountain region, will also be allowed a more gradual phase-in because of less severe ozone pollution in the area. These refiners will be required to meet a refinery average of 150 ppm in 2006 and must meet the 30 ppm requirement in 2007. Small refiners will not be required to meet the 30 ppm standard until 2007. The date for GPA and small refiner gasoline sulfur compliance has been extended an additional 2 years for those refineries that produce 15 ppm diesel at 85 percent of baseline highway diesel production levels.[11]

Consumption of highway-grade diesel (500 ppm sulfur) accounted for 68 percent of the distillate fuel market in 1999,[12] although 9 percent of that fuel went to non-road (rail, farming, and industry) and home heating uses.[13] Higher sulfur distillate (more than 500 ppm) used exclusively for non-road and home heating needs accounted for the other 32 percent of the distillate market. These other distillate markets will also be affected by the new highway diesel standard and may play a role in how some refineries respond to the rule. For instance, instead of investing in ULSD production, some refineries may opt to switch production to non-road or heating markets.

The EPA is in the process of promulgating "Tier 3" non-road engine emission limits around 2005 or 2006, which are expected to be linked to sulfur reduction for non-road diesel fuel.[14] The level of sulfur reduction required for Tier 3 vehicles is highly uncertain because of the diversity of the non-road market. Diesel engines used for farming, construction, rail, and other industrial markets have different performance requirements that need to be reconciled.[15] Both the American Petroleum Institute (API) and National Petrochemical and Refiners Association (NPRA) have expressed concerns about complying with potential non-road standards before full implementation of the 15 ppm highway diesel standards.[16]

In addition to refinery issues, there are concerns about the ability of the distribution system to handle the requirements of the ULSD Rule. Between June 2006 and June 2010, the 80/20 rule will allow up to 20 percent of highway diesel production to continue at the current 500

[7] Energy Information Administration, *Petroleum Supply Annual 1999*, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), Table 3.

[8] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Control Requirements," *Federal Register*, 40 CFR Parts 80, 85, and 86 (February 10, 2000).

[9] National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 3, U.S.A.

[10] U.S. Environmental Protection Agency, *EPA Staff Paper on Gasoline Sulfur Issues*, EPA420-R-98-005 (Washington, DC, May 1998). The average sulfur content has declined since the sulfur content of reformulated gasoline was reduced substantially to meet Phase 2 reformulated gasoline emissions requirements, which became effective in 2000.

[11] The EPA announced on May 4, 2001, that National Cooperative Refining Association and Wyoming Refining would be given additional time to meet the sulfur standard for gasoline. Both refiners are planning to comply with the 2006 highway diesel requirements on time.

[12] Energy Information Administration, *Petroleum Supply Annual 1999*, DOE/EIA-0340(99)/1 (Washington, DC, June 2000), Table 3.

[13] Energy Information Administration, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0525(99) (Washington, DC, September 2000), Tables 19-23.

[14] U.S. Environmental Protection Agency, *Reducing Air Pollution from Non-road Engines*, EPA420-F-00-048 (Washington, DC, November 2000), p. 3.

[15] Nonroad Workgroup, Minutes of the Workgroup's Meeting (Alexandria, VA, January 16, 2000).

[16] *Diesel Fuel News*, Vol. 5, No. 3 (February 5, 2001).

ppm limit. That fuel must be segregated in the distribution system from the remaining 80 percent of highway diesel meeting the 15 ppm limit. As a result, some pipelines, terminals, and retail outlets may temporarily need to carry an extra diesel product, requiring capital investment for the additional infrastructure requirements and additional operating costs for distributing the extra product. Both pipeline operators and fuel marketers are concerned that contamination from higher sulfur petroleum products might require some ULSD to be downgraded to a higher sulfur product that would have a lower market value. Moreover, a second new distillate product may be required if Tier 3 requirements also become effective before 2010.

A number of groups representing refiners and retailers are taking legal action against the ULSD Rule, including the National Petrochemical and Refiners Association (NPRA), the American Petroleum Institute (API), the Society of Independent Gasoline Marketers of America (SIGMA), and the National Association of Convenience Stores (NACS). The four groups have cited concerns about the possibility of inadequate ULSD supply under the Rule. The retailer groups also oppose the phase-in provision of the ULSD Rule ("the 80/20 rule"), because it will temporarily require costly storage of an additional product. SIGMA's lawsuit also questions the feasibility of the 15 ppm sulfur limit on ULSD.[17] On the other hand, the Rule has been strongly supported by a diverse coalition of environmental, manufacturing, regulatory, and trucking groups.[18] State and local regulators are supportive of the ULSD Rule because it is an integral part of their State Implementation Plans for meeting air quality standards.

Some State and local areas have begun to set their own requirements for ULSD. Texas and Southern California have already finalized ULSD regulations, and the State of California is in the process of doing so.[19] During the Bush Administration's review of the Federal ULSD rule, a group of State and local air pollution regulators warned that more States would follow suit with their own regulations if the ULSD rule were delayed or changed in any way.[20]

Methodology

In order to address both the short-term and mid-term supply issues identified by the Committee on Science, this analysis incorporates two different analytical approaches.

Refinery cost analysis addresses the uncertainty of supply in the short term. In addition, mid-term issues and trends are addressed through NEMS scenario analysis.[21] Discussion of the key issues and uncertainties related to the distribution of ULSD is based on interviews with a number of pipeline carriers.

As suggested by the Committee, most of the major assumptions in this report are consistent with those used by the EPA in its Regulatory Impact Analysis (RIA) of the Rule. Before conducting this study, EIA consulted with representatives from diesel engine and emissions control manufacturers, the refining industry, and Government[22] to discuss the methodology and assumptions. EIA also received input through EIA's Independent Expert Review program.[23] On the basis of the information received and a review of other analyses, EIA identified the analysis assumptions that contained the most significant uncertainties. Where possible, sensitivity analyses were developed to provide a measure of uncertainty in the projections.

Assessment of Short-Term Effects of the Rule

For the purpose of assessing the short-term supply situation as the new standard becomes effective in June 2006 (see Chapter 5), industry-level cost curves were

[17] *Diesel Fuel News* (March 19, 2001).

[18] The coalition includes the Alliance of Automobile Manufacturers, the American Lung Association, the Association of International Automobile Manufacturers, the Association of Local Air Pollution Control Officials, the California Trucking Association, the Clean Air Network, the International, Truck and Engine Corporation, Manufacturers of Emission Control Association, the Natural Resources Defense Council, Northeast States for Coordinated Air Use Management, the Sierra Club, the State and Territorial Air Pollution Program Administrators, U.S. Public Interest Research Group, and the Union of Concerned Scientists.

[19] Discussions with Mr. Bill Jordan, Texas Natural Resource Conservation Commission, and Mr. Tim Dunn, California Air Resources Board.

[20] *Diesel Fuel News*, Vol. 5, No. 4 (February 19, 2001).

[21] Energy Information Administration, *National Energy Modeling System: An Overview 2000*, DOE/EIA-0581(2000) (Washington, DC, March 2000), www.eia.doe.gov/oiaf/aeo/overview/index.html.

[22] Contact with diesel engine manufacturers included Cummins, Inc., Mack Truck, Inc., and Caterpillar, Inc. Contact with emission control manufacturers included Johnson Matthey and Engelhard Corporation. Refining industry contacts included the American Petroleum Institute (API), the Cenex Harvest States Cooperatives, UniPure Corporation, Equilon Enterprises, LLC, Lyondell Citgo Refining Company, Ltd., ExxonMobil Refining and Supply Company, Marathon Ashland Petroleum, LLC, and the National Petrochemical and Refining Association (NPRA). Government contacts included the U.S. Department of Energy's Office of Policy and Office of Transportation Technologies and the U.S. Environmental Protection Agency.

[23] Independent expert reviewers were Mr. Raymond E. Ory, Vice President, Baker and O'Brien, Inc.; Mr. Norman Duncan, Energy Institute, University of Houston; and Mr. Kevin Waguespack, PricewaterhouseCoopers.

constructed, based on refinery-specific analysis of investment requirements and operating costs.[24] Unlike the NEMS projections discussed below, the cost curves do not reflect an equilibrium market price.

The cost curves developed for this study are the result of a refinery-by-refinery analysis. Because of the proprietary nature of the data, this analysis does not disclose information about individual refineries. 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).[25]

The technology cost representations were used to develop four sets of cost curves based on four different investment rationales. Within a given supply curve, the relative costs of different groups of refineries provide an indicator of possible supply problems. A large range of compliance costs in which investment costs are much higher for some refiners than for others may be an indication that some refiners may forgo investment. The behavior of refiners will be influenced by their expectation of what others will do and is therefore subject to great uncertainty. In order to explore the uncertainty of refinery behavior and the possible implications for supply, cost curves were developed based on the four different scenarios of investment behavior discussed below:

- **Competitive Investment Scenario.** This scenario assumes that some refineries will produce ULSD in 2006, while others may find it more economical to abandon the market. Refiners that have competitive costs of production are assumed to maintain market shares similar to current highway diesel market shares. Refineries currently producing a relatively low fraction of diesel fuel may abandon the market unless their cost per unit is competitive at current highway diesel production levels.
- **Cautious Expansion Scenario.** Current producers with competitive cost structures for ULSD production and a high yield of diesel production (greater than 70 percent of middle distillates) are assumed to increase production if the unit cost of the increased production is not substantial. Other refineries may also increase their fraction of highway production if economical and if the non-road market will allow. For instance, the Northeast has a strong heating oil market, potentially limiting a shift toward highway diesel production.
- **Moderate New Market Entry Scenario.** This cost curve assumes that a selective number of refineries that are currently producing little or no highway diesel will enter the ULSD market. The underlying premise is that there would be a limited number of companies that think they will be able to gain market share without depressing margins to the extent of undercutting profits. Only a few will make this move, while the rest wait for a clear indication of ULSD margins.
- **Assertive Investment Scenario.** Refineries were assumed to make the requisite investments to either maintain or gain highway diesel market share.

The scenarios discussed above are based on capital cost and return on investment assumptions that are consistent with EPA's analysis. Due to the uncertainty of these assumptions, two sets of sensitivity analysis are also provided. To address the uncertainty associated with the cost of installing or modifying distillate hydrotreaters for producing ULSD, a set of scenarios was developed assuming capital costs for hydrotreater units that are about 40 percent higher than the initial set. An additional set of scenarios explores the impact of assuming a 10-percent after-tax rate of return on investment, used in most of the studies compared in Chapter 7, instead of the 5.2-percent after-tax rate (equivalent to 7 percent before tax) assumed in the initial set.

Assessment of Mid-Term Effects of the Rule

The mid-term analysis for this study was performed using the NEMS Petroleum Market Module (PMM). The PMM represents domestic refinery operations and the marketing of petroleum products to consumption regions. PMM solves for petroleum product prices, crude oil and product import activity (in conjunction with the NEMS International Energy Module and Industrial Demand Module), and domestic refinery capacity expansion and fuel consumption. PMM is a regional, linear programming representation of the U.S. petroleum market. Refining operations are represented by a three-region linear programming formulation of the five Petroleum Administration for Defense Districts (PADDs). PADDs I (East Coast) and V (West Coast) are treated as single regions, and PADDs II (Midwest), III (Gulf Coast), and IV (Rocky Mountains) are aggregated into one region. Each region is considered as a single firm where more than 80 distinct refinery processes are modeled. Refining capacity is allowed to expand in each region over each 3-year period. As a result, cumulative

[24]The EPA and Baker and O'Brien also developed refinery-specific cost analyses, but their estimates did not reflect data related to the quality of crude oil inputs and the quality of diesel fuel components input to downstream units, collected by EIA.

[25]The technology costs were developed in consultation with Mr. John Hackworth and were reviewed by Mr. Ray Ory, one of EIA's independent expert reviewers, and by members of API.

investment for any given year may include investment to meet future product expectations.

Unlike previous ULSD analysis sponsored by the EPA or industry groups, the PMM provides multi-year scenarios. These scenarios reflect market prices rather than average costs and implicitly include investment and import decisions. Because each model region operates as a single firm, the impact of the ABT refinery credit program is also implicitly represented. The PMM cannot differentiate between the costs of different types of refineries, but the impact of the temporary compliance option for small refiners is partially accounted for in this analysis by reducing the refinery production of ULSD by 4 percent prior to 2010.

The PMM was used to develop a ULSD Regulation case based on the provisions of the EPA's final ULSD Rule. Five sensitivity cases were developed for assumptions associated with greater uncertainty, as well as a Severe case, which combines the five sensitivity case assumptions in a single scenario, a No Imports case, and a 10% Return on Investment case. The eight alternative cases explore the impacts of the following assumptions:

- The capital costs associated with distillate hydrotreaters (the Higher Capital Cost case).
- The reliance of refineries on revamped equipment versus new equipment (the 2/3 Revamp case)
- The percentage of ULSD that is downgraded to a lower value product because of contamination from higher sulfur products in the distribution system (the 10% Downgrade case)
- The fuel efficiency loss associated with meeting new diesel emissions standards (the 4% Efficiency Loss case)
- The loss in ULSD energy content resulting from more severe desulfurization processes (the 1.8% Energy Loss case)
- The combined effects of the alternative assumptions in the previous five sensitivity cases (the Severe case)
- The impact of the ULSD Rule assuming that foreign imports meeting the new sulfur standards will not be available (the No Imports case).
- The rate of return on investment (the 10% Return on Investment case).

The PMM provides average annual marginal prices. Because of its aggregate regional and annual nature, the PMM cannot be used to address short-term supply issues. The results of the PMM scenarios assume that, in the long run, refiners will increase supply to meet demand.

Assessment of Distribution and Marketing Effects of the Rule

The temporary compliance and small refinery provisions were incorporated into the Final Rule as a "safety valve" to minimize potential supply problems by allowing up to 20 percent of a refinery's highway diesel fuel production to remain at the current 500 ppm sulfur standard between June 1, 2006, and May 31, 2010, and by allowing small refineries (representing about 5 percent of total diesel fuel production) to delay compliance with the new standard until June 1, 2010. These provisions provide flexibility to refiners during the transition period but will effectively require the distribution system to temporarily handle an additional product. Aside from carrying an additional product, the distribution system will face new challenges related to transporting a very-low-sulfur fuel in the same system with other, high-sulfur products. The discussion of the implications of the ULSD Rule for the pipeline distribution system (Chapter 4) is based on interviews with a number of pipeline companies representing a cross-section of size, capacity, location, markets, corporate structures, and operating modes.[26]

The mid-term scenarios generated by the PMM include additional distribution costs associated with getting the ULSD to market during the transition period and after 2010. The incremental distribution costs reflect both the cost of capital for pipelines, terminals, and retail outlets and the costs associated with downgrading highway diesel that is contaminated during distribution. The capital component of the distribution costs used in this analysis is the same as that used in the EPA's Regulatory Impact Analysis (RIA) and is similar to those estimated by two other studies (Chapter 7). The cost of downgraded product is estimated by EIA using EPA's total

[26]The companies that participated in the interviews included Buckeye Pipe Line Company, Colonial Pipeline, Conoco Pipe Line Company, Kaneb Pipeline Partners, L.P., Kinder Morgan Energy Partners L.P., Marathon Ashland Petroleum, LLC, TE Products Pipeline Company, L.P., and Williams Energy Services.

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downgrade assumption of 4.4 percent and the price differential between ULSD and other diesel.[27] Estimates for the percent of downgraded product range between EPA's 4.4 percent estimate to 17.5 percent by Turner Mason and Associates.[28] Due to the uncertainty about the extent of downgrade that will occur in the pipeline system, EIA has also projected the costs associated with larger downgrade assumptions (see Chapter 6).

[27] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf

[28] Turner, Mason & Company, *Revised Supplement to Report: Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, August 8, 2000)

2. Efficiency and Cost Impacts of Emission Control Technologies

Background

The new ultra-low-sulfur diesel (ULSD) Rule issued by the U.S. Environmental Protection Agency (EPA) requires not only that the sulfur content of transportation diesel fuel oil produced by domestic refineries be drastically reduced by 2007, but also that emission controls on heavy-duty diesel engines be imposed to dramatically reduce emissions of nitrogen oxides (NO_x), particulate matter (PM), and hydrocarbons (HC). This chapter summarizes the new heavy-duty engine emission standards, discusses the feasibility of meeting the standards based on a review of the EPA-identified emission control technology options that might be available, and assesses cost implications of the technology options.

The new ULSD standards finalized by the EPA are crucial to the successful development of emission control equipment for heavy-duty diesel engines. The catalysts to be used in meeting the emission standards can be severely damaged by sulfur contamination. For example, catalyst-based particulate filters for diesel engines have shown significant losses of conversion efficiency with fuel containing 30 ppm sulfur, particularly in colder climates. With respect to NO_x adsorbers, researchers have found that at fuel sulfur levels above 10 ppm, the heavy truck emission standard may not be attainable.

The EPA's final emission standards will affect new heavy-duty vehicles in model years 2004, 2007, and 2010. Although this study focuses on the impact of the 2007 standard, discussion of the 2004 standards and the associated impacts on technology, cost, and efficiency are relevant to the analysis. In 1997, the EPA proposed new emission standards for 2004 and later model year heavy-duty diesel engines that required a combined standard for NO_x and HC of 2.4 grams per brake horsepower-hour (g/bhp-hr).[29] The current standard for NO_x is 4 g/bhp-hr, and the standard for HC is 1.3 g/bhp-hr. The proposed standard was reviewed by industry, and in 1998 the EPA signed consent decrees with several heavy-duty engine manufacturers, stating that the 2004 emission standards would be met by October 2002.[30] The standards for new heavy-duty highway vehicles in model years 2004 and later were finalized July 2000.

In December 2000, EPA published additional standards for on-road heavy-duty diesel engines that would take effect beginning in 2007. These standards will require stricter control of PM (0.01 g/bhp-hr), NO_x (0.20 g/bhp-hr), and HC (0.14 g/bhp-hr) emissions. The new standards apply to diesel-powered vehicles with gross vehicle weight (GVW) of 14,000 pounds or more. The PM standard applies to all on-road heavy- and medium-duty diesel engines. The NO_x and HC standards are to be phased in at 50 percent of new vehicle sales in model years 2007 through 2009. In 2010, all new on-road vehicles will be required to meet the NO_x and HC standards.

For years 2007 through 2009, the EPA allows diesel engine manufacturers flexibility in meeting the NO_x and HC standards.[31] Engine manufacturers are provided the option of producing all diesel engines to meet an average of 2004 and 2007 NO_x and HC emission standards (1.1 g/bhp-hr). Engine manufacturers and EPA have confirmed that the industry intends to design and produce engines that meet the average NO_x/HC emission standard, providing engine manufacturers the ability to comply with the standards by using less stringent emission control systems.[32] If manufacturers produce low-emission engines in 2006, the number produced can be deducted from 2007 production requirements.

Emission Control Technologies

Historically, engine manufactures have met new emissions standards through modifications to engine design. The continuation of this trend is seen in the projection of technologies used to meet the EPA's 2004 emission standards for heavy-duty diesel engines. An EPA-commissioned technology study that addressed

[29] The brake horsepower of an engine is the effective power output, sometimes measured as the resistance the engine provides to a brake attached to the output shaft. A bhp-hr is that unit of work or energy equal to the work done at the rate of 1 horsepower for 1 hour

[30] U.S. Environmental Protection Agency, *Final Emission Standards for 2004 and Later Model Year Highway Heavy-Duty Vehicles and Engines*, EPA420-F-00-026 (Washington, DC, July 2000), p. 4.

[31] U.S. Environmental Protection Agency, *Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements*, EPA420-F-00-057 (Washington, DC, December 2000), p. 2

[32] Based on telephone interviews with engine manufacturers and the U.S. Environmental Protection Agency.

technology, availability, cost, and efficiency concerns concluded that engine manufacturers could meet the 2004 emission standards with engine control strategies—primarily, exhaust gas recirculation (EGR) and high-pressure fuel injection systems with retarded fuel injection strategies.[33] The EPA also stated that other advanced diesel engine technologies—such as wastegated turbochargers, air-to-air after-coolers, advanced combustion chamber design, and electronic controls—could be used to help meet the 2004 emission standards.

Although the EPA states that implementation of cooled EGR will achieve most of the necessary emission reductions and that increases in fuel consumption are expected due to pumping losses, they believe that advanced turbochargers, advanced combustion chamber design, and electronic controls will also be used to overcome losses in efficiency. The EPA also mentions various catalyst technologies that might be used to meet the NO_x and PM standards but concedes that engine manufacturers will opt for engine control strategies to meet the NO_x standard, due to both economic and technological concerns regarding the catalyst technologies for NO_x reduction. The EPA concludes that particulate traps or oxidation catalysts will be used to control PM.[34] The assumptions reflected in the EPA study were recently confirmed when several engine manufacturers reported that they would implement the above-mentioned engine technologies to meet the 2004 standards.[35,36,37]

Whereas engine manufacturers have been able in the past to meet new emission standards by using advanced engine controls and technologies, they will have to rely heavily on component and system development by emission control equipment manufacturers to meet the 2007 standard. In particular, engine manufacturers must implement an exhaust after-treatment catalyst technology to control NO_x emissions.

Several NO_x control after-treatment devices are currently being investigated, including lean-NO_x catalysts, NO_x adsorber catalysts, and urea-based selective catalytic reduction (SCR) devices. Lean-NO_x catalysts have not seen significant improvement in NO_x reduction efficiency during the past 3 years and are not considered a viable option, but NO_x adsorber and SCR systems have shown potential for significant reduction of NO_x emissions.[38] The NO_x absorber catalyst works by temporarily storing NO_x during normal engine operation on the adsorbent. When the adsorbent becomes saturated, engine operating conditions and fuel delivery rates are adjusted to produce a fuel-rich exhaust, which is used to release the NO_x as N_2. The SCR process involves injecting a liquid urea solution into the exhaust stream before it reaches a catalyst. The urea then breaks down and reacts with NO_x to produce nitrogen and water. Using the SCR system, it might be possible to meet the NO_x emission standard without ultra-low-sulfur diesel fuel.

Industry experts have indicated that the SCR system shows more promise than the NO_x adsorber system for reduction of NO_x emissions in truck applications.[39] There is currently no infrastructure in place for the distribution of urea, however, and other issues remain to be addressed, including freezing of the urea solution in extreme weather conditions as well as operator compliance. Several engine manufacturers are working on infrastructure development plans for liquid urea. Although the EPA agrees that the technology is promising, it has serious concerns about compliance issues, because truck drivers may forgo refilling the urea tanks in an effort to save on operating costs. Engine manufacturers are working with the EPA to develop engine control systems to address this and other engineering issues. The SCR technology will not be viable until infrastructure plans are established and engine manufacturers can demonstrate to the EPA that compliance can be assured through reasonable engine control strategies.

Currently, the EPA expects NO_x adsorbers to be the most likely emission control technology applied by the industry.[40] Using current catalyst technology, the fuel-rich cycle reduces fuel efficiency by 4 percent.[41] The majority of the reduction in fuel efficiency comes from

[33]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Control of Emissions of Air Pollution From Highway Heavy-Duty Engines*, EPA420-R-00-010 (Washington, DC, July 2000), p. 21.

[34]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Control of Emissions of Air Pollution From Highway Heavy-Duty Engines*, EPA420-R-00-010 (Washington, DC, July 2000), p. 46.

[35]DieselNet, "Caterpillar Announces New Emission Technology," web site www.dieselnet.com/news/0103cat.html (March 2001).

[36]Newport's Truckinginfo.com, "Mack To Use EGR To Meet '02 Emissions Standards," web site http://www.trcukinginfo.com/news/news_print.asp?news_id=42839 (March 20, 2001).

[37]DieselNet, "Cummins in Support of Cooled EGR Technology," web site www.dieselnet.com/news/0103cummins.html (March 2001).

[38]U.S. Department of Energy, Office of Transportation Technologies, "Impact of Diesel Fuel Sulfur on CIDI Emission Control Technology" (August 21, 2000), p. 2.

[39]Based on telephone interviews with manufacturers of heavy-duty diesel engines.

[40]U.S. Environmental Protection Agency, *Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analyses*, EPA420-R-00-028 (Washington, DC, December 2000), p. V-3.

[41]U.S. Department of Energy, Office of Transportation Technologies, "Diesel Emission Control: Sulfur Effects (DECSE) Program Phase II Summary Report: NO_x Adsorber Catalysts" (October 2000), p. 21.

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the reduction of sulfur in the exhaust stream. The sulfur accumulates on the NO_x adsorber catalyst, and eventually adsorber storage capability is completely lost. Even at ultra-low-sulfur levels, further desulfurization must occur to ensure that the NO_x adsorber is not "poisoned."

To date, no NO_x adsorber system has proven feasible. Although NO_x adsorbers have demonstrated compliance using ULSD (7 ppm), the systems show losses in conversion efficiency after 2,000 miles of operation.[42] Concerns have also been raised about the ability of the technology to perform over a range of operating temperatures and loads. Industry and government research efforts are seeking ways to overcome the obstacles facing the NO_x adsorber technology.

In order to meet the 2007 emission standards for heavy-duty diesel engines, the EPA makes the following assumptions regarding the performance of NO_x adsorber emission control technology:

- Conversion efficiencies will improve so that the overall loss of fuel economy will be only 2 percent: 1 percent for the fuel-rich cycle and 1 percent for pumping losses.
- EGR equipment will be optimized as a result of the improved efficiency of NO_x adsorber emission control equipment. The optimized EGR air-to-fuel mixture will provide a 1-percent increase in fuel efficiency, which will offset the 1-percent loss in efficiency from the fuel-rich exhaust cycle.
- The application of the new emission control technology will provide a 3-percent or greater increase in efficiency by offsetting the fuel efficiency reductions that were incurred to meet the 2004 standard when diesel engine manufacturers manipulated fuel injection timing to optimize for low NO_x emissions.

Based on these assumptions, EPA predicts that there will be no loss in fuel efficiency associated with the NO_x adsorber catalyst designed to meet the 2007 emission standard.[43] Although experts agree that this is possible, it has yet to be proven.[44] Current field tests reveal a 4- to 5-percent fuel efficiency loss with current state-of-the-art technology, which still requires EGR and timing control. Experts agree, however, that NO_x adsorber catalysts are expected to improve and that the associated optimization of EGR and timing control will eventually be achieved.

Technology Costs

The EPA's cost analysis of the technologies required to meet the 2004 standard assumed that fuel injection and turbocharger improvements would occur without the new emission standards. Therefore, when estimating increases in engine costs, the EPA excluded 50 percent of the technology costs in the total cost estimation. The incremental costs for medium-duty engines were estimated to be \$657 in 2004, decreasing to \$275 in 2009. Heavy-duty engine costs were estimated at \$803 in 2004, decreasing to \$368 in 2009.[45]

The EPA also estimated increases in annual operating costs of \$49 for medium-duty engines and \$104 for heavy-duty engines for the maintenance of the EGR system. The cost of the NO_x adsorber emission control system for medium-duty engines was estimated at \$2,564 in 2007, decreasing to \$1,412 in 2012. For heavy-duty trucks, the cost of control technology was estimated at \$3,227 in 2007, decreasing to \$1,866 in 2012.[46] Although engine manufacturers state that these costs are optimistic, no studies have been completed to dispute the EPA estimates.

Efficiency Losses

EPA assumptions for the impacts of the ULSD Rule on diesel engine fuel efficiency are used for the Regulation case in this analysis. Because the emission control technology development needed to meet the 2007 standards remains to be developed, however, a sensitivity case was analyzed to evaluate the possible impacts of fuel efficiency reductions.[47] In the 4% Efficiency Loss case for this study, it is assumed that meeting the emission standards in 2010 will reduce the average fuel efficiency of highway heavy-duty diesel engines by 4 percent, improving to no efficiency loss in 2015. It is assumed in this scenario that engine manufacturers will not be able to overcome fuel efficiency losses in order to meet the standards in 2010, but with continued improvements in NO_x adsorber efficiency and desulfurization catalysts, they will be overcome by 2015.

[42] Manufacturers of Emission Controls Association, *Catalyst-Based Diesel Particulate Filters and NO Adsorbers: A Summary of the Technologies and the Effects of Fuel Sulfur* (August 14, 2000), p. 19.

[43] U.S. Environmental Protection Agency, *Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analyses*, EPA420-R-00-028 (Washington, DC, December 2000), p. V-34

[44] Based on phone interviews with emission control equipment manufacturers.

[45] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Control of Emissions of Air Pollution From Highway Heavy-Duty Engines*, EPA420-R-00-010 (Washington, DC, July 2000), p. 88.

[46] U.S. Environmental Protection Agency, *Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analyses*, EPA420-R-00-028 (Washington, DC, December 2000), p. V-38

[47] Although this case reflects a scenario in which losses in efficiency from emission contol are not overcome by new technology, the considerable time available for research and development may provide government and industry ample time to resolve the fuel efficiency loss issues associated with advanced emission control technologies

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 numbe 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)

Analysis Case	2007	2008	2009	2010	2011	2015	Total, 2007-2015
Total Fuel Expenditures							
Reference	39.45	40.46	41.46	42.19	42.98	45.96	385.63
Regulation	41.37	42.31	43.09	44.40	45.55	47.95	403.24
4% Efficiency Loss	41.37	42.31	43.09	44.58	45.92	48.44	406.21
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	2.38	2.94	2.49	20.58

Source: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, and DSU7TRN.D043001A.

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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 Scanraff, Sweden, installed a hydrotreating facility based on SynTechnology.[48] The Scanraff 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 Scanraff plant is highly selective of its feedstock to achieve the ultra-low sulfur content which may not be generalized to most U.S. refineries.

[48] B. van der Linde (Shell), R. Menon (ABB Lummus), D. Dave & S. Gustas (Criterion), "SynTechnology: An Attractive Solution for Meeting Future Diesel Specifications," presentation to the 1999 Asian Refining Technology Conference, ARTC-99

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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.[49] 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 LGO 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— which Arco termed "EC Diesel"—at its Carson, California, refinery.[50] 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.[51] Arco indicated that the crude slates of the Carson refinery would remain unchanged, with only the operating conditions modified. The refinery had to selectively take out a sulfurous, aromatic cycle oil feed stream to the diesel unit and repeat this every few days for batches. If continuous production were 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.[52]

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.[53] 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 o 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.[54]

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.

[49] L.A. Gerritson, F. Stoop (Akzo Nobel Catalyst), P. Low, J. Townsend, D. Waterfield, and K. Holdes (BP Amoco), "Production of Green Diesel in the BP Amoco Refineries," presented at the WEFA Conference (Berlin, Germany, June 2000).

[50] Now part of BP Amoco.

[51] "Arco's EC Diesel Dominates CARB Advisory Discussion," *Diesel Fuel News* (April 26, 1999), p. 5.

[52] "Equilon Offers 15 PPM Sulfur Diesel for N. California," *Diesel Fuel News* (April 10, 2000), p. 10.

[53] L. Allen (Criterion Catalyst Co.), "Economic Environmental Fuels with SynTechnologies," presented at the World Fuels Meeting, EAA-World Fuels-98 (Washington, DC, Fall 1998).

[54] *Diesel Fuel News* (April 11, 2000), p. 17.

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Refineries with hydrotreaters are likely to achieve production of ULSD on straight runs by modifying catalysts 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 uses. It is generally believed that a two-stage deep desulfurization process will be required by most, if not all refiners, 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 effort 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 hydrotreating unit with moderate adjustments to the operation parameters. Recent advances in higher activity catalysts also help in achieving a higher sulfur removal rate.[55] 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 hydrotreaters would be required, operating at pressures between 1,100 and 1,200 psig.[56] 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 not require thick-walled reactors. The vendors indicated that [illegible] existing hydrotreating unit could be retrofitted with a number of different vessels, including: a reactor, a hydrogen compressor, a recycle scrubber, an interstage stripper, and other associated process hardware.[57]

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.[58] 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 compounds 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

[55]The type of improvement in catalyst activity is illustrated by Akzo Nobel new KF757 cobalt-molybdenum (CoMo) catalyst. Comparing KF 757 with its predecessor catalyst Akzo states, "A diesel unit designed to achieve 500 wppm product sulfur with KF 752 can easily achieve less than 250 ppm product sulfur with KF 757 while maintaining the same operating cycle." Source: C.P. Smit, "MAKFining Premium Distillates Technology: The Future of Distillate Upgrading," presentation to Petrobras (Rio de Janeiro, Brazil, August 24, 2000), p. 4.

[56]National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 7, pp. 132-133.

[57]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-69.

[58]Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000), p. 26.

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.[a] 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.[b] 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 oxidization. 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.[c] 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.[d] 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.[e]

(Continued on page 17)

[a]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, pp. IV-31–IV-32.

[b]National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), p. 75.

[c]Sulfone is any of various sulfur-containing organic compounds having a bivalent radical SO_2 attached to two carbon atoms.

[d]R.E. Levy et al., "UniPure's ASR-2 Diesel Desulfurization Process: A Novel, Cost-effective Process for Ultra-Low Sulfur Diesel," presented at the National Petrochemical and Refining Association 2001 Annual Meeting (New Orleans, LA, March 18-20, 2001).

[e]"Gas-to-Liquids Technology: The Current Picture," *International Energy Outlook 2000*, DOE/EIA-0494(2000) (Washington, DC, March 2000), pp. 59-60; and S. Weeden, "Financial Commitments Brighten 2001 GTL Prospects," *Oil & Gas Journal* (March 12, 2001).

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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.[f]

[f]Web 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.[59]

A processing scheme that has been promoted primarily in Asia and Europe employs a combination of partial hydrocracking and FCC to produce very-low-sulfur fuels. In this scheme a partial conversion hydrocracking 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 strengths 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)[60] 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.[61] 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

[59]U.S. Environmental Protection Agency, *Reducing Air Pollution from Non-road Engines*, EPA420-F-00-048 (Washington, DC, November 2000), p. 3.

[60]NEMS 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/m059(2001).pdf.

[61]The PMM incorporates the technology database from EnSys Energy & Systems, Inc., a consultant to EIA, for refinery processing modeling.

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,[62] 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 stocked, 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[a] (1999 Dollars per Barrel per Day)	Total Capital Cost per Unit[a] (Million 1999 Dollars)
HL1/HS2. . . .	25,000	All except coker gas oil and high-sulfur light cycle oil	1,331	33.3
HD1/HD2 . . .	10,000	All	1,849	18.5

[a]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[a] (1999 Dollars per Daily Barrel)	Total Capital Cost per Unit[a] (Million 1999 Dollars)
New	50,000	100	995	49.8
New	10,000	68	1,807	18.1
Revamp	50,000	100	592	29.6
Revamp	10,000	68	1,210	12.1

[a]Includes only on-site costs.
Source: National Energy Technology Laboratory.

[62]Within 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 notional refinery.

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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.[63]

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 (H_2S) inhibits hydrodesulfurization reactions, scrubbing of recycle gas to remove H_2S 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 H_2S 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.[64] The many caveats within current vendors' statements must be carefully scrutinized, to avoid overestimating the capability or underestimating 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.[65]

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.[66] 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.

[65]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV.

[66]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, pp. IV-63- IV-64.

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 wth 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 refiners 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 refiners 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 refiners to recoup investments.

Profit margins for ULSD could be depressed if refiners build too much capacity, and the fear of overinvestment could lead some refiners to delay investment until more highway diesel production is required. On the other hand, refiners 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. refiners 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 hydrodesulfurization units by 2004 and that 89 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 refiners 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

[67] National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), p. 23.

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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 hydrotreaters 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)

Analysis Case	Front-End Design Workforce	Detailed Engineering Workforce	Construction Workforce
NPC Scenario A	42	32	—
NPC Scenario B	59	45	—
NPC Scenario C	62	56	—
NPC Scenario D	82	49	—
NPC Scenario E	82	49	—
EPA Without Temporary Compliance Option	46	27	[illegible]
EPA With Temporary Compliance Option	30	17	[illegible]

Sources: NPC: National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Table [illegible]. EPA: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, Table IV.B-5.

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

Unit Type	2001-2003	2004	2005	2006	2007	2008	2009	2010
Gasoline Units								
After Promulgation of the Tier 2 Gasoline Sulfur Program	10	37	6	26	[illegible]	[illegible]	—	—
After Promulgation of the ULSD Program	10	37	6	26	5	3	4	6
Diesel Units	—	—	—	63	—	—	—	58

Source: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, Table IV.B-3.

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.

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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.[68] 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 500 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.[69] 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.[70] Typically, as common carriers (which transport for any shipper on a nondiscriminatory basis), oil pipelines are subject to State authority if

[68] Buckeye Pipe Line Company, Colonial Pipeline, Conoco Pipe Line Company, Kaneb Pipeline Partners, L.P., Kinder Morgan Energy Partners L.P., Marathon Ashland Petroleum LLC, TE Products Pipeline Company, L.P., and Williams Energy Services.

[69] Joanne Shore, Energy Information Administration, "Supply of Chicago/Milwaukee Gasoline Spring 2000," web site www.eia.doe.gov/pub/oil_gas/petroleum/presentations/2000/supply_of_chicago_milwaukee_gasoline_spring_2000/cmsupply2000.htm (August 9, 2000).

[70] According to the Association of Oil Pipe Lines, *Shifts in Petroleum Transportation 1999* (2001), pipelines account for 75 percent of the ton-miles of oil transported in the United States. (One ton of oil transported one mile equals one ton-mile.)

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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 produc 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

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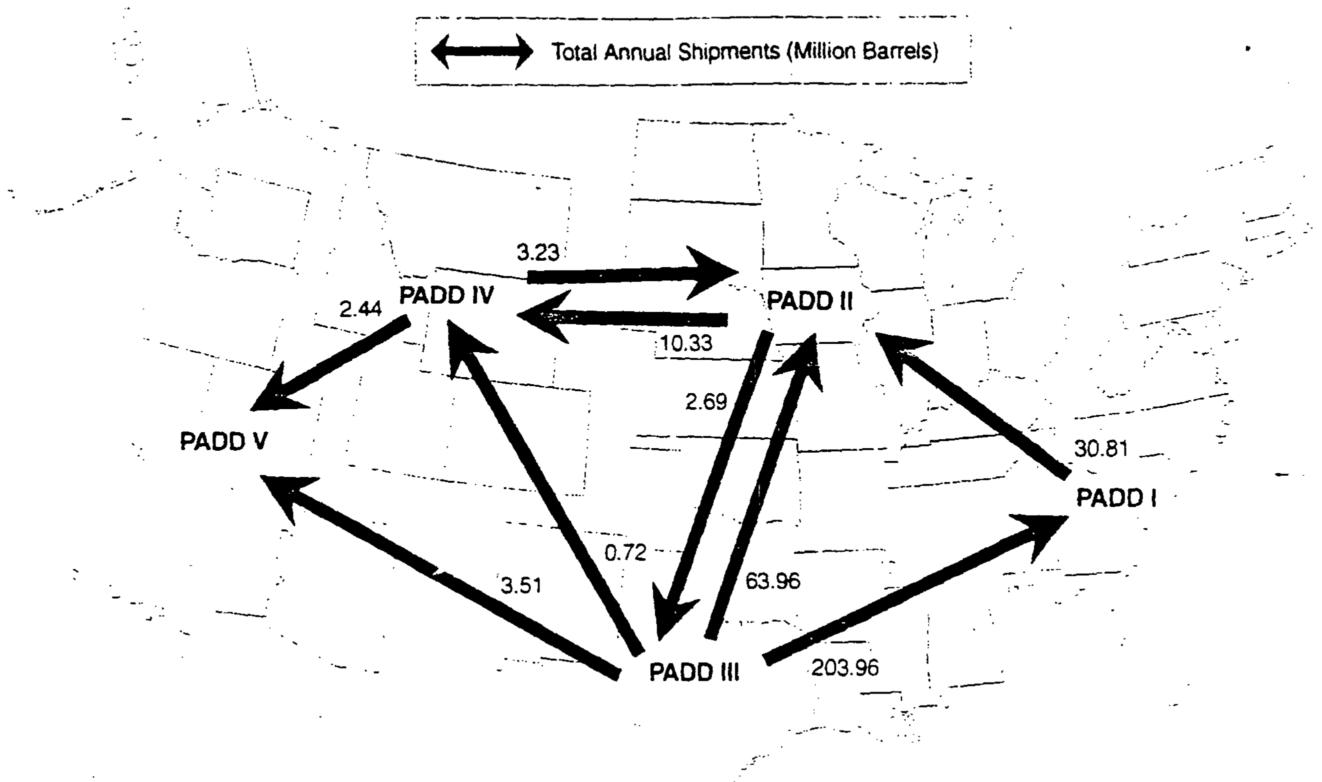
Figure 1. Pipeline Shipments of Distillate Fuels Between PADDs, 1999



Note: Includes low-sulfur (highway) diesel fuel and high-sulfur distillate fuel oil (non-road diesel fuel and heating oil).
Source: Energy Information Administration. *Petroleum Supply Annual 1999*. DOE/EIA-0304(99)/1 (Washington. DC, June 2000). Table 33.

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 ransit. 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 refiners. 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 refiners, 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.

[71] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-93.

[72] Cited in the EPA's documents as "Comments of Association of Oil Pipelines (AOPL) on the NPRM, Docket Item IV-D325." Cited here s "AOPL Comments."

[73] AOPL Comments, p. 2.

[74] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-93.

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 trailback from [heating oil] to [low-sulfur diesel] indicates that trailback 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 trailback 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 trailback 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 trailback, 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 cost was with the 4.4 percent downgrade assumption.[80] 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

[75] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, pp. IV-93–IV-94

[76] AOPL Comments, Attachment, p. 2

[77] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-96

[78] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-94.

[79] AOPL Comments, Attachment, p. 2 and p. 5.

[80] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-124

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.

[81] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Part 80.527 (January 18, 2001).

[82] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR, Preamble (January 18, 2001), p. 281.

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.[83] 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."[84] 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 refiners and importers than to pipelines and other downstream parties.

The designated testing method will be ASTM 6428-99,[85] not the widely-used ASTM 5453-99, 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 5453-99 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.)

[84]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-99.

[85]U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements; Final Rule," *Federal Register*, 40 CFR Part 80.580(a)(2) (January 18, 2001).

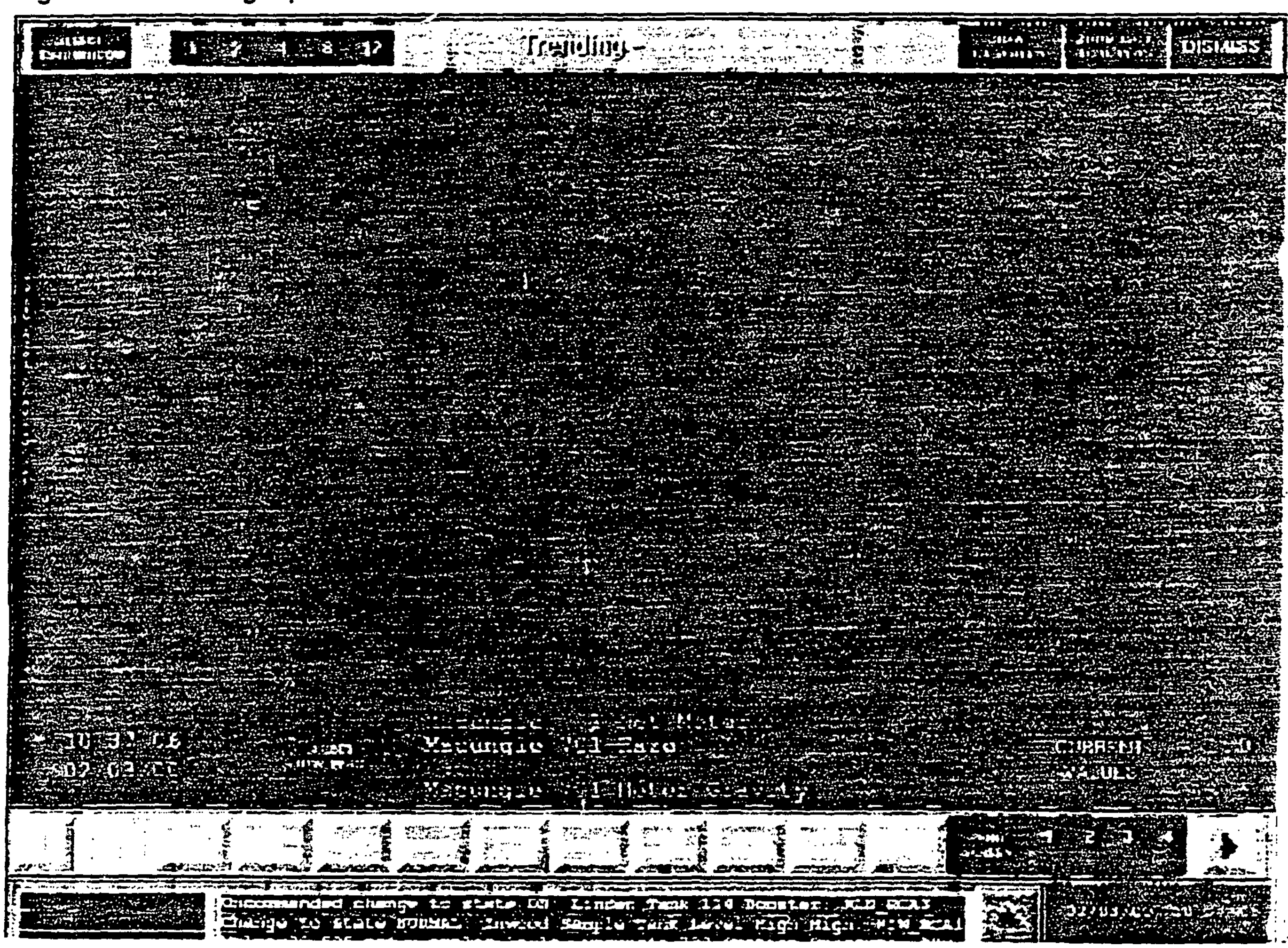
designated method. Hence, even those with experience using ASTM 5453-99 cannot be confident of the impact of the designated method on their testing practices. A downstream testing tolerance of 2 ppm will be allowed,[86] but whether this is the appropriate level, given the designated method's performance, also cannot be determined until the method is adapted for use with diesel fuel and correlated in the round robin.

Upon their entry 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

Figure 2. Monitoring Pipeline Product for Contamination



Note: Taken from an oil pipeline control center's SCADA (Supervisory Control and Data Acquisition) system, this screen illustrates gasoline contamination (indicated by the drop in flashpoint) during a change from one kerosene batch to a second kerosene batch. The Net Meter stops climbing and shows where the pipeline was shut down to investigate the source of the problem (likely a late cut leaving gasoline/kerosene mix in the tank line that became evident when the pipeline began to draw product from the tank). The time scale across the screen is in hours. There is no similar monitoring available for ULSD.

[86]U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Part 80.580(a)(4) (January 18, 2001).

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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).

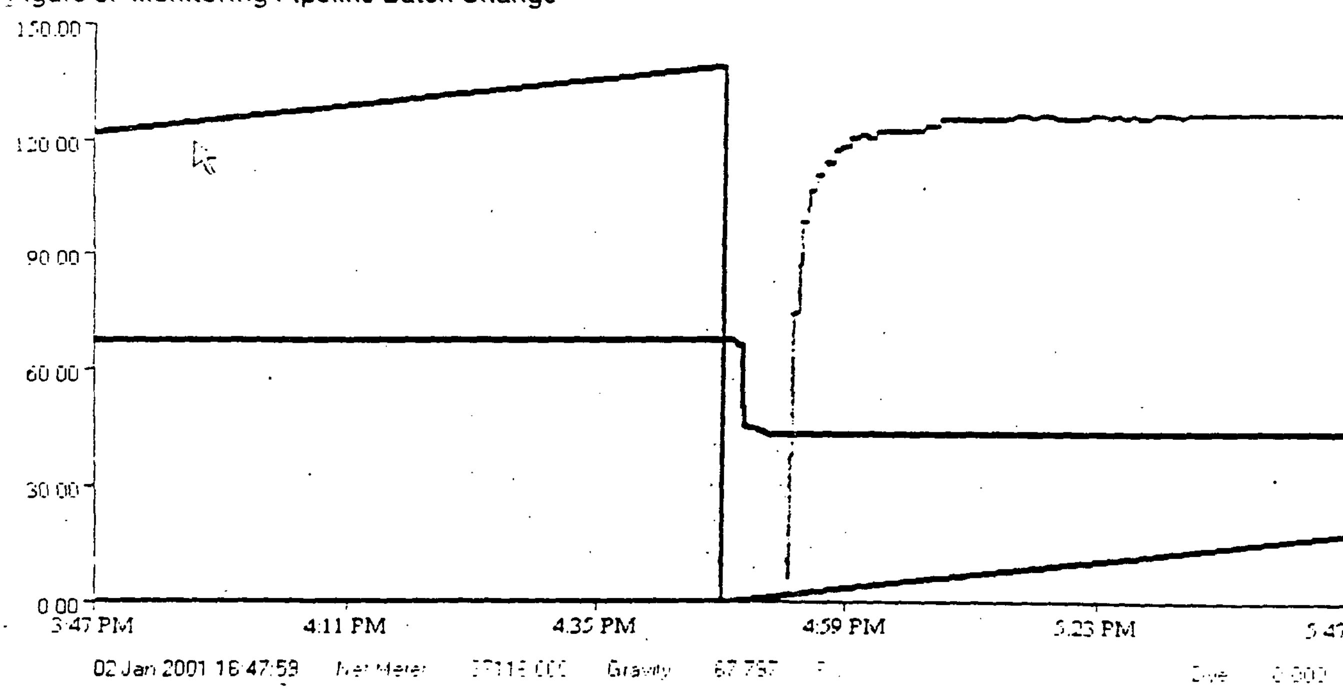
Some oil pipelines use in-line testing equipment to detect contamination close to and downstream from potential source locations where foreign or off-specification material might be inadvertently introduced into pure material (Figure 2). Early detection of contamination gives operators flexibility in 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.[87] 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



Note: This screen capture, originating from the pipeline's SCADA system, illustrates a normal batch change from gasoline (67 API gravity) to kerosene (47 API gravity and 123 minimum flashpoint).

[87] [(9,965 x 7) + 935 x (35 x 3,000)] / 10,000 = 17.5 ppm.

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 refiners 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 refiners 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.[88]

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.[89]

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

[88]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-134.

[89]U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-134.

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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.[90] 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.[91]

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.[92]

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.[93] 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 suggests. 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

[90] John Huber, Petroleum Marketers Association of America, "Letter to U.S. EPA, Re: AMS-FRL-6705-2," Submitted to the public docket on August 11, 2000.

[91] John Huber, Petroleum Marketers Association of America, "Letter to U.S. EPA, Re: AMS-FRL-6705-2," Submitted to the public docket on August 11, 2000.

[92] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-133.

[93] Other rate administration methods are available from the Commission, but they are even less frequently used.

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

[94] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-121.

[95] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-121.

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- 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).[96] The EPA noted that "numerous commenters to the proposed rule indicated that they believed that the 15 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)."[97]

While it is possible that some refiners 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 refiners. 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 refiners could also decide to export distillate products if they are in the right location.

Because there are other markets for distillate products, some refiners 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 refiners to recoup the full cost of environmental standards."[98] Overly aggressive expansion to produce ULSD could result in similar oversupply of product and reduced margins, and some refiners 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 refiners 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 precompliance 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.[99] 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.[100]

[96] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-33.

[97] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-33.

[98] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter IV, p. IV-34.

[99] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," Pre-publication Final Rulemaking (December 21, 2000), pp. 158-160.

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

Cost Analysis

To assess the supply situation during the transition to ULSD in 2006, estimates of ULSD costs and supply were developed based on refinery-specific analysis of investment requirements. The relative costs can provide insights into whether refiners will make the investments to produce ULSD and give an indication of possible supply. Four scenarios describing investment behavior under different assumptions were developed to provide a range of possible responses to the ULSD Rule.

Using refinery-specific data collected by the Energy Information Administration (EIA), the ULSD product costs are estimated for each refinery based on its 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. Cost curves were then developed in a three-step process. In the first step the cost of producing ULSD for each refinery was estimated for several strategies of ULSD production, based on refinery operation data for 1999. The strategies start by maintaining ULSD production at current highway diesel production levels. Then they consider both reductions and increases from current production to find the most economical level of production for individual refineries. In the second step the cost and volume information for individual refineries is used to construct cost curves for the U.S. refining industry using a variety of scenario assumptions about how refiners may respond with refinery investment in preparation for summer 2006, when ULSD requirements for highway diesel begin. The third step consists of adjusting the cost curves to reflect changes in refinery capacity from 1999 to 2006.

Appendix D describes in detail the refinery-by-refinery analysis and development of the cost model used as the basis for developing the cost curves. Table 6 provides samples of the ULSD cost model results for cases representing various refinery configurations and situations. The case descriptions in the table indicate whether the refinery in that particular case falls within the higher or lower part of the range in terms of hydrotreater unit capacity, sulfur content of the hydrotreater feed, and the fraction of cracked stock in the feed. The costs in this analysis assume a 5.2-percent after-tax return on

Table 6. Sample Results from the ULSD Cost Model

Refinery Characteristics and Costs	Case A	Case B	Case C	Case D	Case E	Case G	Case H	Case I	Case J	Case K	Case L
Hydrotreater Capacity Range[a]	H	H	H	H	H	L	L	H	H	H	HR
Feed Sulfur Content Range[a]	H	H	L	L	H	H	H	M	M	M	M
Percent Cracked Stock Range[a]	H	H	H	H	L	H	H	H	M	M	M
Revamp or New Unit[b]	N	R	N	R	R	N	R	N	N	R	R
Current Highway Diesel Production (Thousand Barrels per Day)	50.0	50.0	50.0	50.0	50.0	10.0	10.0	0.0	32.4	32.4	32.4
Hydrotreater Feeds (Thousand Barrels per Day)											
Straight-Run Distillate	34.0	34.0	34.0	34.0	50.0	6.8	6.8	33.0	25.3	25.3	18.4
Light Cycle Oil	8.0	8.0	8.0	8.0	0.0	1.6	1.6	4.0	2.1	2.1	0.0
Coker Distillate	8.0	8.0	8.0	8.0	0.0	1.6	1.6	23.0	5.1	5.1	2.3
Total	50.0	50.0	50.0	50.0	50.0	10.0	10.0	60.0	32.4	32.4	20.7
Hydrogen Consumption (Standard Cubic Feet per Barrel)	550	550	402	402	248	550	550	590	395	395	305
Feed Sulfur Content (Parts per Million)											
Straight-Run Distillate	9,000	9,000	1,100	1,100	9,000	9,000	9,000	6,000	6,000	6,000	6,000
Light Cycle Oil	25,000	25,000	3,800	3,800	0	25,000	25,000	15,000	13,000	13,000	13,000
Coker Distillate	22,000	22,000	5,700	5,700	0	22,000	22,000	14,000	14,000	14,000	14,000
ULSD Cost Components (1999 Dollars per Barrel)											
Hydrotreater											
Capacity Changes	0.73	0.55	0.70	0.55	0.36	1.21	0.74	0.72	0.81	0.55	0.49
Other	0.83	0.74	0.75	0.68	0.54	0.96	0.79	0.87	0.78	0.67	0.62
Hydrogen Production											
Capacity Changes	0.20	0.20	0.22	0.22	0.05	0.35	0.35	0.30	0.19	0.19	0.00
Other	0.52	0.53	0.55	0.54	0.12	0.56	0.57	0.88	0.40	0.41	0.13
Sulfur and Other	0.27	0.06	0.07	0.06	0.06	0.41	0.10	0.19	0.19	0.07	0.08
Total Cost (1999 Dollars per Barrel)	**2.54**	**2.08**	**2.27**	**2.05**	**1.12**	**3.49**	**2.56**	**2.97**	**2.37**	**1.88**	**1.31**
Total Cost (1999 Cents per Gallon)	**6.0**	**5.0**	**5.4**	**4.9**	**2.7**	**8.3**	**6.1**	**7.1**	**5.6**	**4.5**	**3.1**

[a]H = refinery in the higher range; M = refinery in the middle range; L = refinery in the lower range.
[b]N = new unit; R = revamped unit.
Note: Only refineries in Petroleum Administration for Defense Districts (PADDs) I-IV are included in the short-term analysis.
Source: Energy Information Administration, Officeof Integrated Analysis and Forecasting.

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investment, which is estimated to be equivalent to the 7-percent before-tax return on investment assumed in the EPA's analysis.

The cases in Table 6 were designed to represent the types of individual refinery situations that lie behind the cost curve results. Cases A and B represent refiners producing highway diesel fuel as a high fraction of their distillate pool. These refineries run a higher sulfur crude oil, do not have hydrocracking facilities, and have relatively large-scale highway diesel production. Thirty-two percent of the highway diesel they produce comes from cracked stock, which is about the average for Petroleum Administration for Defense District II (PADD II) (see Appendix D, Table D1). The cost of producing highway diesel at current production levels in the refineries of Cases A and B is 6.0 cents per gallon if a new hydrotreater is required and 5.0 cents per gallon if the current hydrotreater can be revamped. The cost of the incremental hydrogen to produce ULSD represents 28 percent of the added cost for Case A and 35 percent for Case B.

Cases C and D have the same volumes as A and B but use a lower sulfur crude oil. The cost of the added hydrogen is similar to the result for Cases A and B, because this analysis is estimating the cost to produce ULSD with 7 ppm sulfur rather than the current 500 ppm. Total costs, however, are just 0.1 cents per gallon lower for a revamped unit (Case D compared to Case B) and 0.6 cents per gallon lower for a new unit (Case C compared to Case A).

Case E shows a refinery producing ULSD only from straight-run distillate derived from a high-sulfur crude. The cost of production from a hydrotreater that has been revamped is only 2.7 cents per gallon. This is slightly more than half the cost of Case B, which has to handle 32 percent cracked stocks.

Cases G and H represent the same mix of hydrotreater feed as in Cases A and B, but the total feedstock volume is only 10,000 barrels per day, compared to 50,000 barrels per day in Cases A and B. This is the type of situation represented by comparing ULSD production in PADD IV with that in PADD II and PADD III. For a new hydrotreater unit, the ULSD cost would be 8.3 cents per gallon (2.3 cents per gallon higher than in Case A). If the unit can be revamped, the cost is 6.1 cents per gallon (1.1 cents per gallon higher than in Case B).

Some refineries currently produce high volumes of distillate product but no highway diesel. These refineries might consider entering the highway diesel market when the ULSD Rule takes effect if they anticipate that the price differential between ULSD and their other distillate products can more than offset the added investment and operating costs they would incur. Case I illustrates a non-road diesel producer converting to the production of highway diesel. The refinery runs a moderately high-sulfur crude oil and has substantial volumes of cracked distillates from the fluid catalytic cracker (FCC) and coker units. Because of quality requirements for non-road diesel products, cracked stocks still make up 45 percent of the feed to the hydrotreater for highway diesel production. The large percent of cracked stocks means a moderately high per-barrel investment and operating cost for the hydrotreater. Additionally, the per-barrel cost for hydrogen is quite high. Most of the refineries with high-volume distillate production and no highway diesel production had costs of highway diesel production in the higher portion of the cost range.

Cases J, K, and L provide an illustration of refineries achieving improved economics by reducing the volume of ULSD diesel below current highway production levels. As shown in Table 6, the cost of added hydrogen is generally a large component of the cost of producing ULSD. The cost for hydrogen grows as the fraction of cracked stocks increases, eventually requiring the construction of new hydrogen production capacity. However, if there is only a modest percent of cracked stock in the hydrotreater feed and the refiner reduces the input to the hydrotreater, then the incremental hydrogen requirement for ULSD production can be provided by existing refinery production sources.

Cases J and K show the costs for a new and revamped hydrotreater for a refinery running a medium-sulfur crude and with 22 percent cracked stock in the highway diesel production pool. Case L shows that if the input level is reduced from 32,400 barrels per day to 20,700 barrels per day when the unit is revamped, then the cost of ULSD production is reduced from 4.5 cents per gallon to 3.1 cents per gallon. Given the costs for Cases K and L, the preferred option for the refiner would be Case K if the price differential between highway and non-road diesel exceeds 6.9 cents per gallon and Case L if the differential is less than 6.9 cents per gallon.[101]

These sample cases highlight several situations that can cause refineries to have potentially high ULSD production costs and discourage them from investing to produce ULSD. Small refineries with less than 10,000 barrels per day of highway diesel production will have very high relative costs unless they can revamp an existing unit. The fraction of cracked stocks in the ULSD hydrotreater feed is extremely important. The need for hydrogen increases with the fraction of cracked stocks and may require new hydrogen production capability. If a refinery's other distillate products are primarily

[101] Calculated by taking the difference in total cost (1.88 × 32.4 – 1.31 × 20.7) divided by the change in volume (32.4 – 20.7), expressed in cents per gallon.

non-road diesel fuels with cetane requirements that limit the volume of cracked stocks, then it is often impossible for the refinery to reduce the cracked stocks going into highway diesel. Thus, refineries with moderate cracked stocks and a smaller scale will have high ULSD cost, and refineries with high cracked stocks and a moderate to large scale may also have ULSD costs that they view as uncompetitive.

Analysis of ULSD Production Decisions

Economic Considerations

Scenarios are analyzed to estimate the volumes of ULSD that refiners might produce at the beginning of the ULSD requirement in the summer of 2006. Each scenario defines a set of strategic principles that might characterize the economic rationale behind investment decisions that may be commonly made by refiners in this situation. Refiners have a choice as to how much ULSD they produce. Some refiners may decide to produce no highway diesel when the ULSD Rule comes into effect. While most refiners who are currently producers of highway diesel will likely continue to produce it, they could increase or decrease production from current levels. Because there is uncertainty associated with refiners' behavior, four supply scenarios were constructed, any one of which may turn out to be closest to the actual behavior of the refining industry in this situation.

In making the ULSD decision a refiner will look at the available options, analyze the costs to produce various levels of ULSD, and determine the impact on other distillate products. Then the refiner will try to estimate his relative competitive position for producing ULSD. The competitive assessment considers the cost of ULSD production for other refiners and looks at the mid-term competition for market share, including an analysis of current market share, regional market competition, the impact of new entrants that may have a significant cost advantage, synergies with other refineries within the same company, and potential changes in the price differential between ULSD and non-road fuels on a mid-term basis.

In a number of past instances when refiners have been required to meet new product specifications, they have not only made facility changes that would enable them to meet the demand for the product with new specifications, but have done so in such numbers and volumes that their ability to supply the market has exceeded market demand. In the case of ULSD, refiners have more choice in deciding to participate in the highway market or alternatively to produce products only for non-road distillate markets. This choice becomes a particular issue for refiners facing an expensive investment decision and the likelihood that they would be at a significant competitive cost disadvantage relative to other marke competitors.

While most U.S. refiners look upon gasoline as an essential product, they could operate in the refinery business without producing any highway diesel. Thus, it is possible that some refiners will cease or significantly decrease highway diesel production when ULSD specifications take effect in 2006. This would create a transition market in which some refiners with higher costs would decrease production and be replaced by more cost-competitive refiners.

The set of more cost-competitive refiners falls into two categories—those increasing production of highway diesel from current levels and those currently producing little or no highway diesel. Will refiners in the second group jump into the market because they recognize that they would have a competitive position, or will they wait to see how the supply and margin picture unfolds before making a large-dollar commitment? Later entrants into the market could also be the beneficiaries of improved technologies that reduce the cost of compliance.

Refiners who estimate that their costs to produce ULSD are on the high end of the range will be far less likely to invest to produce ULSD. No one wants to be the marginal supplier after making a large investment, especially when the product is a secondary fuel product. The question is what differential cost will be perceived to be too high—is it 1 or 2 cents per gallon above what the refiner perceives is the average cost in the market? How does the refiner assess the possible competitive threats of a large-volume refiner who has previously not been a highway diesel producer but may now enter the market with better economics to produce highway diesel and reduce market prices? Refiners will likely try to retain highway market share, even if their relative competitive cost is modestly above the average cost in the region, rather than shifting into new markets. Refining companies with multiple refineries will view strategies in the context of their total system and could rebalance production on a system basis.

One of the key decisions in preparing to produce ULSD is whether to build a new hydrotreater or revamp an existing unit. This analysis assumes that revamps are more likely if a refinery installed new distillate hydrotreating units in the 1990s, or if the proportion of cracked stocks in the refinery's hydrotreater feed is small. New units are assumed at refineries where current hydrotreating capacity is less than highway diesel production. As shown in Table 7, the estimates indicate that 46 percent of the refineries in PADDs I-IV, accounting for 63 percent of highway diesel production capacity, would revamp existing units. PADD IV has the

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Table 7. Estimate of Revamps and New Hydrotreaters for ULSD Production

Region	Number of Refineries			Percent Revamp	ULSD Production Volume (Thousand Barrels per Day)			Percent Revamp
	Revamp	New	Total		Revamp	New	Total	
PADD I	4	7	11	36	139	77	216	64
PADD II	14	13	27	52	442	158	599	74
PADD III	22	23	45	49	603	423	1,026	59
PADD IV	5	10	15	33	46	72	117	39
Total	**45**	**53**	**98**	**46**	**1,229**	**729**	**1,957**	**63**

PADD = Petroleum Administration for Defense District.

Note: Although 98 refineries are considered in this analysis, 87 are current producers of low-sulfur diesel. Not all of these refineries are expected to produce ULSD economically.

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

lowest proportion of revamps because of the larger amount of cracked stocks that refineries in that region must process. PADD II has the highest percentage of revamps because of the extensive upgrading that took place in the early 1990s and the moderate levels of cracked stocks in the feed. The EPA assumed that 80 percent of ULSD production capacity would be revamped units.

Supply Scenarios

The first of the four supply scenarios was developed based on the rationale that there is a high probability that refiners will produce at least a moderate level of ULSD. In the other three scenarios there is decreasing probability that the additional volumes would be produced. The description of the specific scenarios follows:

- **Scenario 1—Competitive Investment.** The first scenario includes only those refiners who are likely to prepare to produce ULSD in 2006. They currently hold market share and are estimated to be able to produce ULSD at a competitive cost. Refiners with highway diesel as a relatively low fraction of their distillate production are assumed to abandon the market unless their cost per unit of production is competitive at current highway diesel production levels. Some refiners are assumed to reduce highway diesel production below current levels when they have a more competitive ULSD production at a reduced production rate.

- **Scenario 2—Cautious Expansion by Competitive Producers.** In this scenario, refiners base ULSD production decisions on the assumption that the price differential between ULSD and non-road distillate products will remain wide. Current producers with competitive cost structures for ULSD production and high fractions of highway diesel production (greater than 70 percent of total distillate production) are assumed to maintain current production levels and may even push production of ULSD toward 100 percent of distillate production if only minor increases in per unit production costs occur at increased volume. Other refiners are also assumed to increase their fraction of highway production if the economics are only slightly poorer at higher volumes. Those whose current production is focused primarily on non-road markets are assumed to stay with those markets.

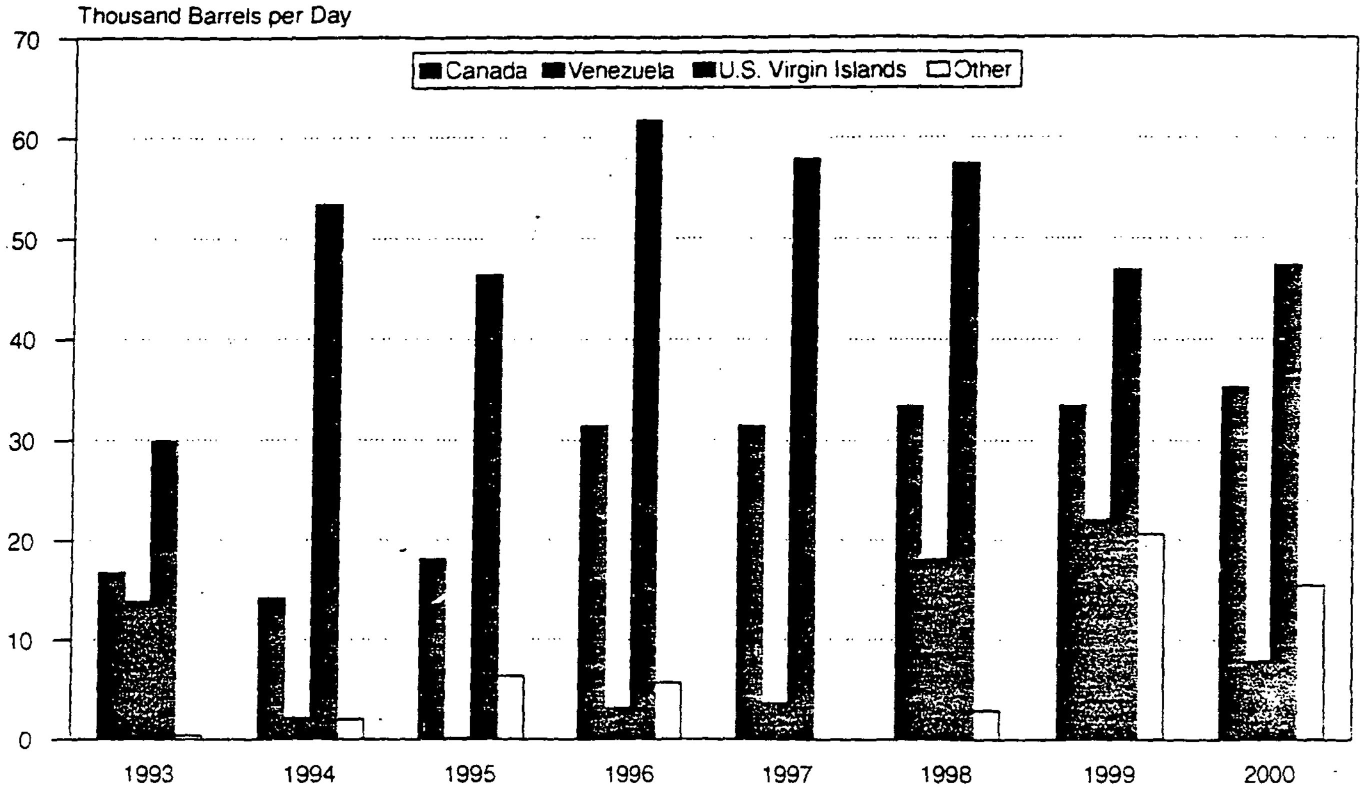
- **Scenario 3—Moderate New Market Entry.** While refineries that are currently producing little or no highway diesel may be hesitant to jump into the ULSD market, this scenario assumes that a select few will decide to take the risk. This is based on the belief that a limited number of refineries think they can gain market share without depressing the price differential between ULSD and non-road diesel to the extent of ruining margins and return on investment. These refiners are assumed to have favorable cost structures for ULSD production (probably in the lower third).

- **Scenario 4—Assertive Investment.** The fourth scenario assumes that a larger number of refiners will compete to increase their shares of the ULSD market. In this scenario, refiners believe that most of their competitors are overly cautious, and that they can succeed by taking a contrary strategy (which in reality is adopted by far more refiners than anticipated).

Imports

Historically, imports have been a small part of low-sulfur diesel supply. The only significant volumes of low-sulfur diesel fuel have been imported into PADD I, which totaled 123,000 barrels per day in 1999 then declined slightly in 2000 to 106,000 barrels per day (Figure 4). Imports made up 5 percent of low-sulfur diesel product supplied for the United States as a whole in 2000 and 14 percent of product supplied in PADD I. The PADD I imports come from three main sources—Canada, the Virgin Islands, and Venezuela. Low-sulfur diesel imports from the Virgin Islands reached 62,000 barrels per day in 1996 and have fallen to 47,000 barrels per day in 2000. Imports from Canada, which have been fairly constant for the past few years, totaled 35,000 barrels per day in 2000. Imports from Venezuela grew sharply in 1998 and 1999, to 22,000 barrels per day in 1999, before falling to 8,000 barrels per day in 2000.

Figure 4. Imports of Low-Sulfur Diesel Fuel into PADD I, 1993-2000



Source: Energy Information Administration, Form EIA-814, "Monthly Imports Report."

Other countries are also planning to lower the sulfur content of diesel fuel. Canada has announced plans to require a 15 ppm sulfur diesel fuel in mid-2006, mirroring the U.S. regulation.[102] A 50 ppm ULSD becomes mandatory across Europe in 2005. The European Commission is also discussing a gradual phase-in to 10 ppm sulfur, starting with a 10-percent supply requirement in January 2007.[103]

Given these changes, Canadian refiners currently exporting to the United States may make the investment to produce ULSD for the U.S. market. The East Coast has been the main market for a large refinery in the Virgin Islands that is jointly owned by Amerada Hess and PdVSA, Venezuela's national oil company. Both of the plant's owners see the United States as a strategic market. Venezuela is planning to upgrade its domestic refineries, but because it is also interested in expanding its presence in Latin American markets,[104] it is not clear whether it would supply ULSD to the U.S. market.

Refineries worldwide will be investing to produce lower sulfur diesel fuel. Even a refinery designed to produce diesel with 50 ppm sulfur could produce some amounts at less than 15 ppm. Thus, it is conceivable that limited amounts of ULSD could be imported from other sources. In the early part of the transition to ULSD, imports beyond historical levels probably are less likely and quantities less than historical levels probably are more likely.[105]

Demand Issues

The number of vehicles that actually need ULSD when the regulation takes effect in 2006 will be small. The EPA has mandated that 80 percent of the refinery output of less than 500 ppm diesel fuel be ULSD in order to provide retail availability for the trucks that need ULSD. As a result, the supply of ULSD will be much larger than the demand provided by vehicles that need ULSD. The concern is whether enough fuel will be available to supply all highway diesel vehicles.

Current production of low-sulfur diesel fuel is greater than what is required by the market. Highway diesel fuel consumption accounted for 86 percent of transportation distillate demand in 1999. Yet low-sulfur diesel product supplied (a surrogate for demand) has nearly equaled transportation distillate demand in recent years (Figure 5). Consequently, the amount of low-sulfur

[102] Public Works and Government Services Canada, *Canada Gazette*, Vol. 135, No. 7 (February 17, 2001), p. 454.
[103] *Diesel Fuel News* (March 5, 2001), p. 11.
[104] *Oil Daily* (February 27, 2001), p. 2.
[105] EIA's Office of Oil and Gas is planning to issue a report in 2001 on the availability of product imports.

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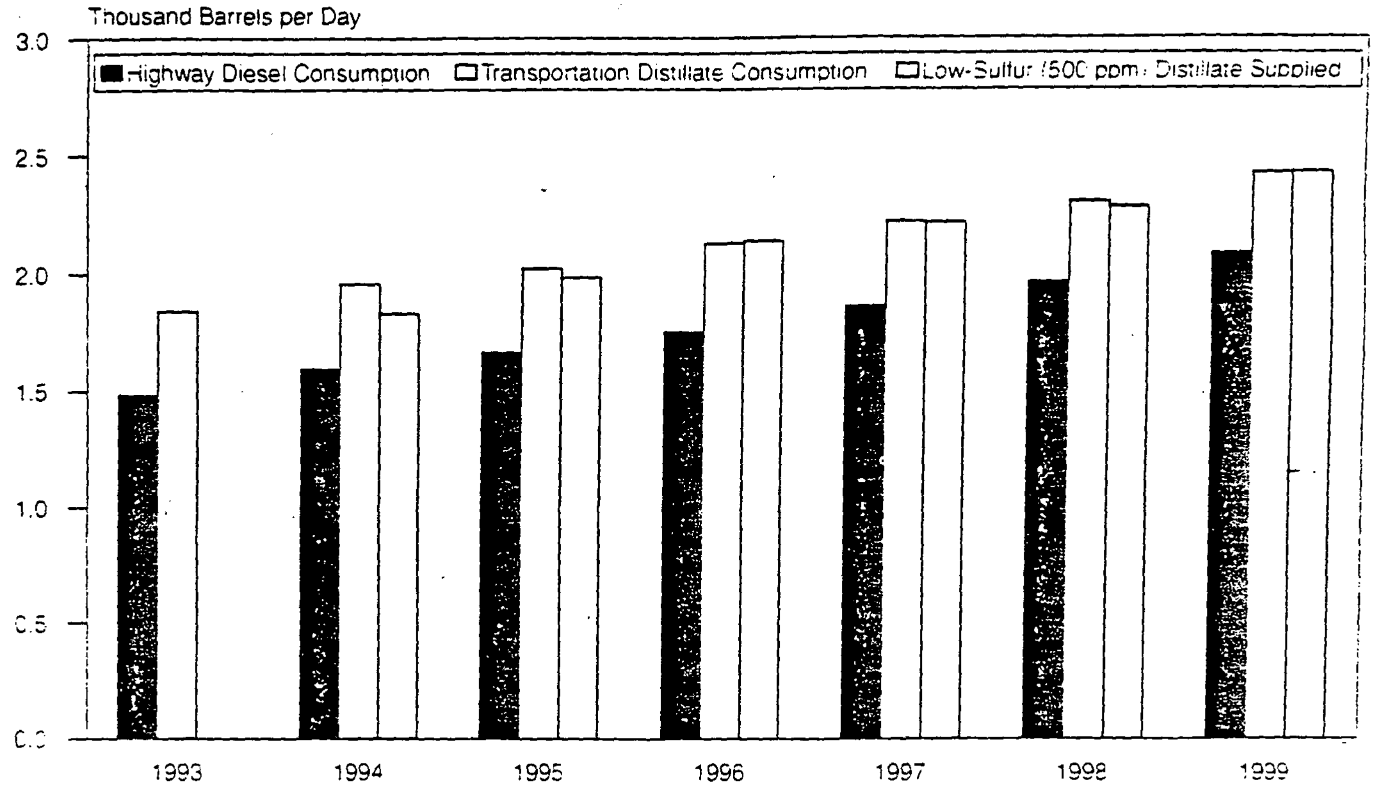
Figure 5. Low-Sulfur Diesel Consumption and Product Supplied, 1993-1999



Sources: Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA-0340, and *Fuel Oil and Kerosene Sales*, DOE/EIA-0525 (Washington, DC, 1993-1999).

diesel fuel currently being consumed in the market is more than 15 percent higher than that required for highway vehicles. There are several reasons for this. The logistics of the distribution system dictate in some areas that only one type of fuel can be distributed. Because the price differential between low-sulfur diesel and other distillate products has been only 2 to 3 cents per gallon or less in recent years, the incentive to maintain separate product infrastructure has not been great. An important question is the extent to which the demand for ULSD will remain above that required for highway vehicles after the ULSD regulation takes effect in 2006. A larger price differential between ULSD and higher sulfur distillate products may provide some incentive to avoid consuming ULSD in markets where it is not required, but in some areas it may continue to be impractical to distribute more than one product.

It is also unclear how much 500 ppm sulfur diesel fuel will be in the market after the regulation takes effect. Refiners will be investing for the long term and not just to produce 80 percent ULSD in the transition period, and many refiners (if they invest to produce ULSD at all) may be producing 100 percent ULSD in the transition period. Some refiners could continue to supply 500 ppm diesel fuel by purchasing credits, and some small refiners could continue to produce 500 ppm sulfur fuel until 2010 (see box on page 45).

For the above reasons, the amount of ULSD actually needed to balance demand in 2006 is highly uncertain. A range of demand estimates has been developed to account for some of the uncertainty. In the mid-term analysis for this study, transportation distillate demand in PADDs I-IV[106] in the 2/3 Revamp case (see Chapter 6) amounts to about 2.7 million barrels per day. At the U.S. level, transportation distillate demand is projected to be 3.0 million barrels per day in 2006, increasing by 3.2 percent per year from the 1999 level of 2.4 million barrels per day. This compares to an average rate of increase of 3.5 percent per year from 1982 to 1999. Transportation distillate demand rose sharply from 1982 to 1989 and again from 1991 to 1999, at annual average growth rates of 4.7 and 4.0 percent, respectively, but fell in 1990 and 1991, at the time of the Iraqi invasion of Kuwait.

The probable downgrading of some ULSD to 500 ppm sulfur diesel in the distribution system was not taken into account in this part of the analysis. The requirement to produce 80 percent ULSD is at the refinery gate, and

[106] PADD V was not included in this analysis because supply concerns are less of an issue in the transition period and the requirement for CARB diesel makes the PADD V market different from PADDs I-IV.

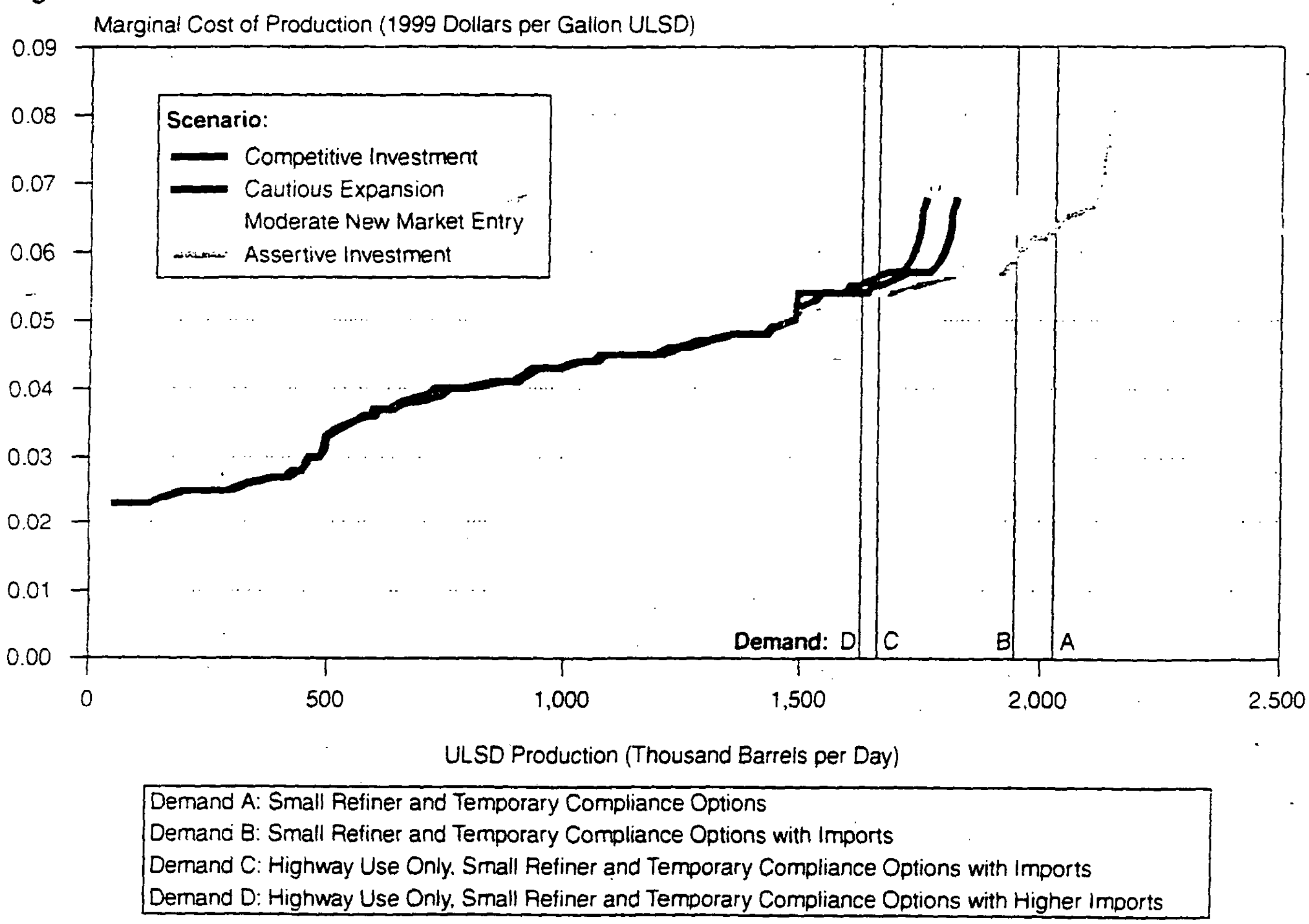
supplies that are downgraded to a higher sulfur level in the distribution system can still be sold as highway diesel during the transition period.

Cost Curves and Demand Estimates for 2006

Figure 6 shows the combined cost curves for PADDs I-IV for each of the scenarios, together with four estimates of demand.[107] The EPA estimates that, under the small refiner option, up to 5 percent of the market could delay making the transition to ULSD until 2010.[108] In addition, the temporary compliance option mandates that ULSD production must constitute 80 percent of low-sulfur diesel production. Assuming the full extent of the small refiner, temporary compliance, and credit trading provisions of the Rule, ULSD demand is estimated at just over 2.0 million barrels per day (Demand A). As indicated above, imports from the Virgin Islands and Canada are likely to continue. At their recent historical level of 80,000 barrels per day, imports would reduce domestic demand for ULSD to 1.95 million barrels per day (Demand B, which matches the demand projection in the mid-term analysis described in Chapter 6). Demand C in Figure 6 is based on the same assumptions as Demand B and, in addition, assumes that ULSD will be used only for highway consumption (86 percent of transportation distillate demand), resulting in a demand estimate of 1.7 million barrels per day. Demand D assumes a higher estimate for imports—116,000 barrels per day—which was the level for PADDs I-IV in 2000.

The cost curves in Figure 6 show the estimated volumes of ULSD that could be produced at increasing cost levels. The curves show the wide range of costs to produce ULSD across the population of U.S. refiners that might choose to become ULSD producers. There are some refiners at the upper range of the cost curves that would

Figure 6. ULSD Cost Curve Scenarios with 2006 Demand Estimates



Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043001A.

[107] A range of demand estimates are shown in Figure 6, but no feedback effects are represented. Feedback effects are included in the mid-term analysis (Chapter 6).

[108] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-134.

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have much higher costs and could have concerns that margins in the marketplace would not be high enough to provide a satisfactory rate of return.

The cost curves in Figure 6 were developed using capital cost and return on investment assumptions consistent with those used in the EPA's analysis. Those assumptions were used in order to provide a comparison with the EPA's analysis results and should not be viewed as the assumptions that EIA considers the most likely. However, concerns about the adequacy of ULSD supply are based on the possible reluctance of higher cost producers to invest to produce ULSD in 2006. Because of the uncertainty of these assumptions, two additional sets of supply scenarios are provided, using higher capital cost assumptions and a higher required return on investment, as discussed later in this chapter.

Total ULSD production on the Scenario 1 (Competitive Investment) and Scenario 2 (Cautious Expansion) cost curves extends beyond the lower demand estimates (C and D) and would meet the highway demand estimates even if no ULSD imports were available. In Scenario 3 (Moderate New Market Entry), production just reaches the mid-term analysis demand estimate that includes imports (Demand B). In Scenario 4 (Assertive Investment), ULSD production surpasses the mid-term analysis demand estimate that does not include imports. None of the supply curves, however, provides enough supply to reach the demand estimate that does not include the temporary compliance option (see Table 8 below). Some refiners may be able to produce ULSD with a cost of about 2.5 cents per gallon; however, at the volumes needed to meet demand, costs are estimated at 5.4 to 6.8 cents per gallon.[109] ULSD prices could show an even higher differential if supply falls short of demand.

The four factors that have the strongest influence on the cost of producing ULSD are the production volume of 500 ppm diesel, the fraction of cracked stocks in the feedstock, the scale of the hydrotreater unit, and whether a new or revamped unit is required.

500 ppm Diesel Supply Issues in 2006

In 2006, 500 ppm highway diesel could come from two sources: either from refiners who produce both 500 ppm and 15 ppm highway diesel or from refiners who are now producing highway diesel but who choose not to make investments to produce ULSD and purchase credits to sell 500 ppm diesel. Few refineries are assumed to fall into the first group. Possible candidates would be refiners with large current production of highway diesel who have multiple distillate hydrotreating units and decide to revamp or replace a large unit to produce ULSD and maintain a second unit to produce 500 ppm highway diesel. This would also mean that the refiner would anticipate selling the 500 ppm diesel as non-road diesel in 2011, because building one large hydrotreater in 2006 would be more economical than building a second hydrotreater for ULSD in 2010. If the decision is made to invest to produce ULSD, a refiner is likely to invest to produce the full volume of highway diesel as ULSD. Some product that fails to meet the ULSD specifications could be downgraded to 500 ppm diesel fuel and sold as highway diesel during the transition period, but few refiners are assumed to produce both 15 ppm and 500 ppm diesel.

Production of 500 ppm highway diesel can clearly come from refiners who are now producing low-sulfur highway diesel and decide not to convert their refinery facilities in 2006. In Scenario 2, the number of non-producers of ULSD in PADDs I-IV totals 21. The characteristics of the 21 refineries that are the potential sources of 500 ppm highway diesel production in 2006 in Scenario 2 differ across the various PADDs. PADD I has 5 refineries and PADD II has 5 refineries that are assumed not to invest to produce ULSD. Nine of these ten refineries currently produce less than 10,000 barrels per day of highway diesel, and the other is under 20,000 barrels per day.

The profile of the PADD III refiners is quite different from those in the other PADDs. While PADD III has some small refineries in this group, several moderately large refineries are also included, which accounts for the fact that PADD III represents 56 percent of the total volume of PADD I-IV production that is estimated not to convert from low-sulfur diesel to ULSD in 2006. Most of these refineries are on the high end of the cost range and would have to build new units and/or deal with relatively high fractions of cracked stocks to produce ULSD.

Six refineries in PADD IV are estimated to have relatively high costs of ULSD production and are assumed not to invest to produce ULSD. The PADD IV refiners are relatively small. Most have some cracked stocks in the highway diesel feed stream and would need to build new units. The refiners not producing ULSD would need to obtain waivers or purchase credits to continue to sell 500 ppm diesel fuel into the highway market.

[109] These are marginal costs on the industry supply curve, based on average refinery costs for producing ULSD. These cost estimates do not include additional costs for distribution, estimated at 1.1 cents per gallon in the mid-term analysis. Costs were not adjusted to take sulfur credit trading into account, because of the uncertainty about whether trading would occur and the value of the credits. If credit trading occurred, costs could be reduced.

Twenty-nine refineries in Scenario 1 are in the cost range below 4 cents per gallon, and all are refineries for which it is assumed that the existing unit could be revamped. Most of these refineries have little or no cracked stocks in the hydrotreater feed to produce ULSD. For the few that do have cracked stocks, a revamped unit at a reduced throughput was found to obtain better economics of ULSD production and put them in the cost range under 4 cents per gallon. Twenty-five refineries are in the cost range from 4 to 5 cents per gallon. Thirteen are assumed to construct new units, and most of these refineries have a low percentage of cracked stocks in the hydrotreater feed. A couple of units in this cost range are assumed to reduce throughput from current highway diesel production levels. Above 5 cents per gallon, a couple of refineries with a high percentage of cracked stocks are assumed to revamp existing units. The rest, which have moderate levels of cracked stocks, are assumed to build new units. The refineries above 5 cents per gallon also include a number of smaller refineries with ULSD production under 10,000 barrels per day.

Regionally, PADD IV has the highest estimated costs for ULSD production. The refineries in PADD IV are smaller on average, have more cracked stocks to process, and have the lowest proportion of revamps. In PADD I, a large heating oil market provides an outlet for some of the more difficult streams to hydrotreat so it tends to show lower costs for producing ULSD. PADD II refineries are also toward the lower end of the cost curve. They tend to be more moderate in size (which gives better economies of scale), have moderate levels of cracked stocks, and had extensive revamps in the early 1990s to put them in a better position to upgrade to produce ULSD. PADD III has a mixture of small and large refineries with a variety of configurations and as a result shows a wide range of lower and higher cost ULSD producers. Some of the refineries in PADD III are among the highest as far as the proportion of cracked stocks in the feedstock going to the hydrotreater. Sixty-four percent of the refineries in PADD IV that are assumed to produce ULSD in Scenario 4 have estimated costs greater than 5 cents per gallon compared to 31 percent in PADD III, 22 percent in PADD II, and 17 percent in PADD I.

Scenario 1 has the lowest production volume of the four scenarios but the highest probability that production volumes of ULSD will at least reach these estimates in 2006. Of the 87 refineries in PADDs I-IV that currently produce highway diesel, only 66 are estimated to produce ULSD in Scenario 1. Of the 21 refineries that are estimated to terminate ULSD production in Scenario 1, the cost of ULSD production ranges from 6 to 13 cents per gallon.[110] Two-thirds of these refineries currently produce less than 10,000 barrels per day of highway diesel. PADD IV refineries are disproportionately in the higher cost range.

Scenario 2 assumes that the number of refineries that will produce ULSD is the same as in Scenario 1, but that these refineries will increase production if their competitive position is not greatly affected. Comparing Scenario 3 to Scenario 2, ULSD production is estimated to increase at nine refineries, and one refinery that currently produces only non-road distillate product is assumed to enter the ULSD market. All of these factors raise the estimated production level in Scenario 3 by 129,000 barrels per day over that in Scenario 2.

The probability of reaching the total volume production of Scenario 4 is the lowest. In this scenario, refineries with higher costs of production are assumed to enter the ULSD market in 2006. The added production volumes in Scenario 4 come from three types of situations. First, some refineries are assumed to expand production beyond the Scenario 3 level if unit costs are only slightly

Table 8. Supply and Demand Estimates in the Reference Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,763	1,823	1,952	2,143
Number of Refineries Producing ULSD		66	66	67	74
Differences Between Supply and Demand					
Small Refiner Option	2,533	-770	-709	-580	-389
Small Refiner and Temporary Compliance Options (Demand A)	2,026	-264	-203	-74	117
Small Refiner and Temporary Compliance Options with Imports (Demand B)	1,946	-184	-123	6	197
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports (Demand C)	1,662	100	161	290	481
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports (Demand D)	1,626	136	197	326	517

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043C01A.

[110] The highest estimated costs by region are 9 cents per gallon for PADD I, 13 cents per gallon for PADD II, 7 cents per gallon for PADD III, and 12 cents per gallon for PADD IV.

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higher. Second, five of the refineries entering the market were viewed in Scenario 3 as having too high a cost. The third and largest portion of additional volume comes from two refineries that currently are not producers of highway diesel. All of the additional volume in Scenario 4 comes from refiners with costs of ULSD production higher than 5 cents per gallon.

Table 8 shows the differences between the demand and supply estimates. The largest shortfall, which occurs between Scenario 1 (assuming the most cautious investment strategy) and the highest demand estimate, is estimated at 770,000 barrels per day. The widest surplus, 517,000 barrels per day, is under Scenario 4 (the most aggressive investment strategy) and the lowest demand estimate that also accounts for import availability. Assuming the mid-term analysis demand estimate, which is similar to the *AEO2001* projection, Scenarios 3 and 4 project sufficient supply.

Some analysts contend that demand could exceed the estimates in this analysis that assume the temporary compliance option of 80 percent ULSD production. Most refiners that invest to produce ULSD will plan to produce 100 percent ULSD unless they have a market for the higher sulfur product after 2010. Those producing 100 percent ULSD will generate credits which can then be sold to those who decide to delay investing to produce ULSD. Credit trading programs have been successful in the utility industry, but how well credit trading will work in a less-regulated industry remains unclear. Refiners may be less than enthusiastic about selling credits to their competitors that would allow them to sell product produced at a lower cost in the same market as ULSD, possibly at a price similar to the price of ULSD.[111] Refiners who wait to invest can also take advantage of improvements in technology that could help them compete more effectively with those who invested early. Credits could increase sharply in value if markets were tight, but they would have less value if supplies were ample.

To provide a further range of demand estimates, Tables 9 and 10 show the projections for high and low macroeconomic growth cases along with the supply estimates from the cost curves. Transportation distillate demand is projected to increase by 4.0 percent per year from 1999 to 2006 in the high macroeconomic growth case and by 2.7 percent per year in the low macroeconomic growth case.

Table 9. Supply and Demand Estimates in the High Economic Growth Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,763	1,823	1,952	2,143
Number of Refineries Producing ULSD		66	66	67	74
Differences Between Supply and Demand					
Small Refiner Option	2,669	-906	-846	-716	-526
Small Refiner and Temporary Compliance Options	2,135	-372	-312	-183	8
Small Refiner and Temporary Compliance Options with Imports	2,055	-292	-231	-103	88
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,756	7	66	196	387
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,720	43	104	232	423

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run HM2001.D101600A

Table 10. Supply and Demand Estimates in the Low Economic Growth Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,763	1,823	1,952	2,143
Number of Refineries Producing ULSD		66	66	67	74
Differences Between Supply and Demand					
Small Refiner Option	2,447	-685	-624	-495	-304
Small Refiner and Temporary Compliance Options	1,958	-195	-134	-6	185
Small Refiner and Temporary Compliance Options with Imports	1,878	-115	-54	74	265
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,604	159	220	348	540
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,568	195	256	385	575

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run LM2001.D101600A

[111] Many analysts contend that the prices of ULSD and 500 ppm diesel will converge in the phase-in period, because most trucks can use 500 ppm fuel but only 20 to 25 percent of production will be 500 ppm fuel. The higher demand than supply will tend to push the price to the same level as ULSD. The need to purchase credits to sell 500 ppm product will also tend to push up its price.

Two additional sets of the four supply scenarios are provided that vary the hydrotreater capital cost assumptions and the return on investment assumption. The capital costs assumed in the initial set of four scenarios in this chapter are similar to those used in the EPA analysis (see Chapter 7 for a comparison of capital cost assumptions). Because of the uncertainty associated with the cost of installing distillate hydrotreating capable of producing diesel fuel containing less than 10 ppm sulfur, a second set of scenarios was developed assuming capital costs for the hydrotreater units that are about 40 percent higher than the initial set (Figure 7). The higher capital costs in this scenario reduce the projected production of ULSD by 25,000 to 55,000 barrels per day and increase the cost estimates from 0.4 cents per gallon to 1.0 cents per gallon.

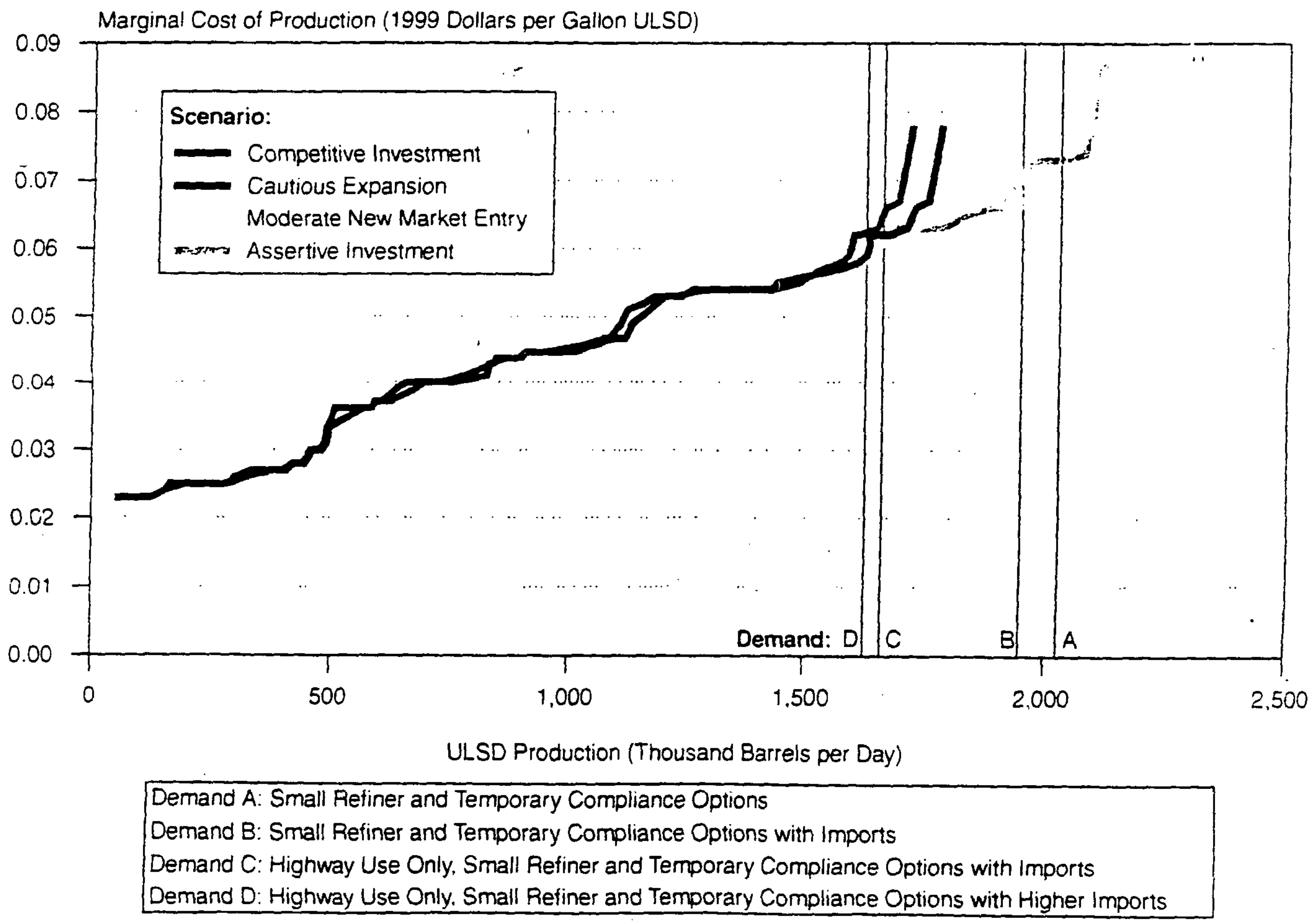
A third set of supply scenarios was developed assuming a 10-percent required return on investment (Figure 8), rather than 5.2 percent assumed in the initial set of scenarios. The higher assumed rate results in a reduction in production of 40,000 to 66,000 barrels per day across the four scenarios. The cost estimates increase by 0.8 to 1.2 cents per gallon from the first set of scenarios. Because of the reduced volumes, estimated production levels in Scenario 3 fall short of the demand level projected in the mid-term analysis (Demand B) in both the higher capital cost and higher required return on investment sensitivities (Tables 11 and 12).

Balancing Demand and Supply in 2006

These supply curves, along with the demand estimates for 2006, indicate the possibility of a tight diesel market when the ULSD Rule is implemented. Supply scenarios that assume more cautious investment indicate inadequate supply compared with the demand levels projected in the *Annual Energy Outlook 2001*. Only more aggressive investment scenarios or lower demand cenarios show adequate supply to meet estimated demand. This analysis compares supply and demand at an aggregate level. Maintaining a balance of supply and demand across regions and throughout the distribution system would be more difficult.

Improvements in supply could result if more refiners undertook investments to produce ULSD, if capacity expansions by refiners were greater than anticipated in

Figure 7. ULSD Higher Capital Cost Sensitivity Case Cost Curve Scenarios with 2006 Demand Estimates



Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043001A.

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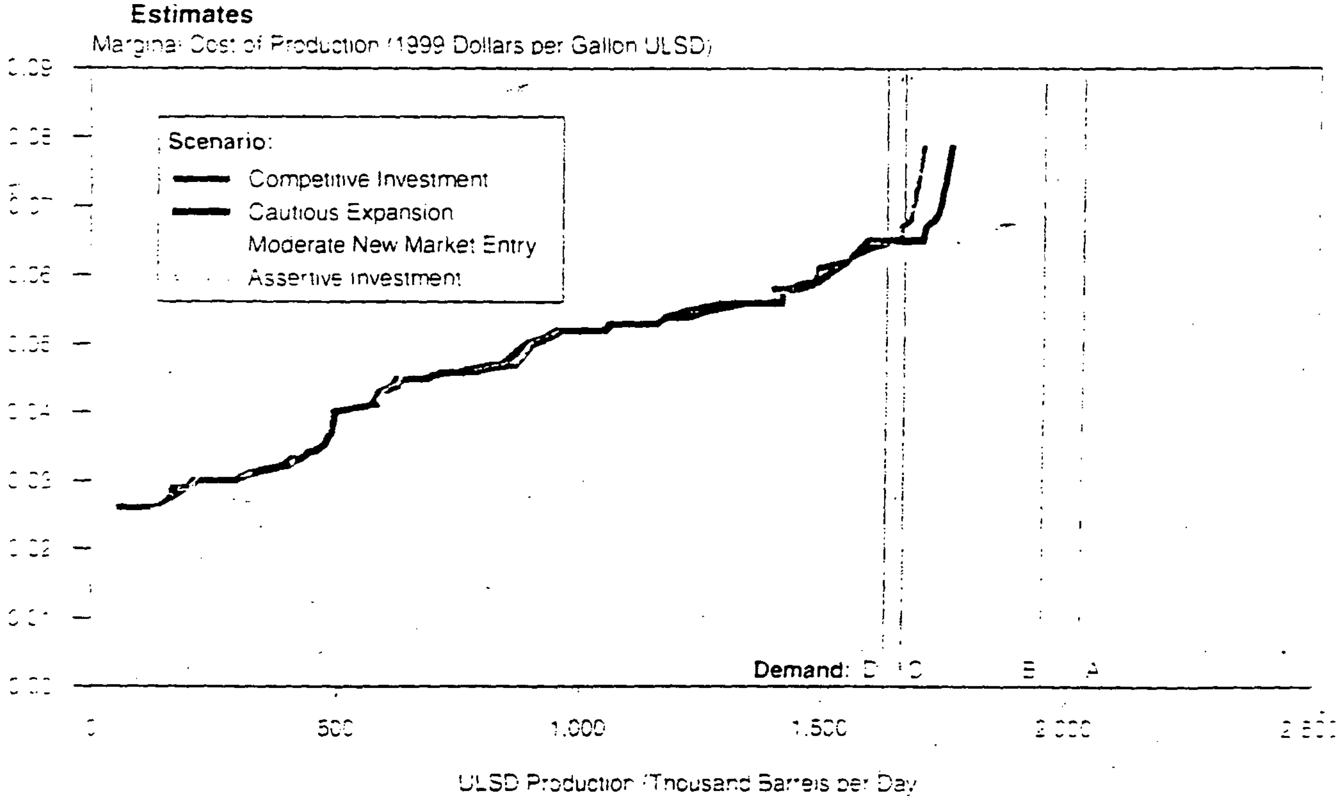
this analysis, and/or if more imports were available. On the demand side, slower growth in the highway diesel market than these demand estimates and/or curtailing of ULSD consumption for non-road uses would also improve the situation.

If supplies fall short of demand, sharp price increases could occur to balance supply and demand. That type of situation could result in a number of responses, some of which could begin to occur as soon as the price differential between ULSD and other products started to widen—possibly even before it became clear that a market supply problem existed. Refiners would attempt to maximize ULSD production. Some additional production may be possible by, for example, shifting some non-road distillate or jet fuel streams into ULSD. This would be limited, however, because only the lower sulfur streams could be used and additional hydrotreating may be necessary. Imports of jet fuel or other products could then replace the lost production of those fuels. Additional imports of ULSD could be forthcoming if there were large price differentials between markets. Such responses would require higher costs, however, because lower cost options would be exercised first.

Sharply higher prices would also curtail demand for diesel fuel. Truckers would reduce consumption to the extent possible and try to pass higher fuel costs to customers, who would then look for alternative means to transport goods.

In 2006, the quantity of fuel actually needed for vehicles requiring ULSD will be much less than the required 80 percent of diesel production. If it becomes apparent that the supply is inadequate, or that markets are becoming tight, additional low-sulfur diesel supplies could become available if the required proportion of ULSD production were reduced. Allowing more 500 ppm diesel into the highway market could alleviate some of the stress on the market. If the requirement were 70 percent instead of 80 percent, for example, the demand estimates shown in Table 8 would be reduced by 217,000 to 253,000 barrels per day, enough to eliminate the shortfalls indicated except for Demand A in Scenario 1 and the highest

Figure 8. ULSD 10% Return on Investment Sensitivity Case Cost Curve Scenarios with 2006 Demand Estimates



Demand A: Small Refiner and Temporary Compliance Options
Demand B: Small Refiner and Temporary Compliance Options with Imports
Demand C: Highway Use Only, Small Refiner and Temporary Compliance Options with Imports
Demand D: Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports

Sources: Cost curve scenarios: Appendix C. Demand estimates: National Energy Modeling System, run DS...

Table 11. Supply and Demand Estimates in the Higher Capital Cost Sensitivity Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,721	1,782	1,897	2,118
Number of Refineries Producing ULSD		61	61	61	72
Differences Between Supply and Demand					
Small Refiner Option	2,533	-812	-751	-636	-415
Small Refiner and Temporary Compliance Options	2,026	-305	-244	-130	92
Small Refiner and Temporary Compliance Options with Imports	1,946	-225	-164	-50	172
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,662	58	119	234	455
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,626	94	155	270	491

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043001A.

Table 12. Supply and Demand Estimates in the 10% Return on Investment Sensitivity Case, 2006
(Thousand Barrels per Day)

	Demand	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Total Supply		1,702	1,760	1,912	2,078
Number of Refineries Producing ULSD		61	61	63	71
Differences Between Supply and Demand					
Small Refiner Option	2,533	-831	-773	-621	-455
Small Refiner and Temporary Compliance Options	2,026	-325	-266	-114	51
Small Refiner and Temporary Compliance Options with Imports	1,946	-245	-186	-34	131
Highway Use Only, Small Refiner and Temporary Compliance Options with Imports	1,662	39	97	249	415
Highway Use Only, Small Refiner and Temporary Compliance Options with Higher Imports	1,626	75	133	285	451

Sources: Cost curve scenarios: Appendix D. Demand estimates: National Energy Modeling Sytem, run DSU7INV.D043001A.

demand estimate across all scenarios. However, a lower requirement for ULSD production would reduce retail availability for the vehicles that require ULSD. Other responses providing greater flexibility, increasing participation, and encouraging technological improvements would also help to alleviate supply concerns.[112]

Given the variety of responses, it is difficult to know the magnitude or duration of a possible tight market situation. Supply shifts and demand responses would require time before the effect would be felt. It would take time for additional imports to enter the market, and importers would have to believe that prices would remain high enough for long enough to make it worthwhile to divert supplies from other markets.

Summary

Whether there will be adequate supply is one of the key questions raised by the House Committee on Science in its request for analysis. To assess the supply situation during the transition to ULSD in 2006, cost curves and estimates of ULSD supply are developed based on refinery-specific analysis of investment requirements. Supply is estimated for four scenarios of investment behavior, and a range of demand is projected for comparison with the supply curves. In addition, two other sets of supply sensitivities are provided, assuming higher capital costs and higher required return on investment.

Supply scenarios that assume more cautious investment indicate inadequate supply compared with the demand levels projected in the *Annual Energy Outlook 2001*. Only more aggressive investment scenarios or lower demand cenarios show adequate supply to meet estimated demand. The two sets of supply sensitivities show even lower production estimates than the initial set. This indicates the possibility of a tight market supply situation when the ULSD Rule takes effect in 2006. While considerable uncertainty exists in both the supply and demand estimates, this analysis indicates that even though the market could see supply meet demand at a cost increase for production between 5.4 and 7.6 cents per gallon, there are a number of scenarios in which inadequate supply of ULSD could result.

[112]Short-term responses are possible, such as the regulatory response that took place when the 500 ppm diesel fuel requirements came into effect on October 1, 1993. As a result of localized outages and price spikes, the EPA sent a letter to marketers and major consumers of diesel fuel granting "enforcement discretion" in cases of extreme diffi :ulty in obtaining supplies, extending through October 22, 1993.

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6. Mid-Term Analysis of ULSD Regulations

Assumptions

The National Energy Modeling System (NEMS) was used to perform petroleum market analysis of the impact of new requirements for ultra-low-sulfur diesel fuel (ULSD) from 2007 through 2015. The Petroleum Market Module (PMM) of NEMS were modified to produce a ULSD Regulation case. Analysis of the Regulation case focuses on changes relative to a reference case using the oil price and macroeconomic assumptions of the *Annual Energy Outlook 2001* (*AEO2001*) reference case but including some adjustments to provide a more accurate reflection of the diesel fuel market. The differences between the reference case for this study and the *AEO2001* reference case are discussed in Appendix B.

The projected investment costs and average marginal prices resulting from the NEMS analysis represent the investment and price levels necessary to meet all demand requirements under the new ULSD Rule. As discussed in Chapter 5, some refiners may choose to drop out of the highway diesel market or even close down instead of investing for compliance with the Rule. ULSD supply could be inadequate in the short term if enough refineries chose to forgo investment. The NEMS analysis does not capture this uncertainty of supply, because NEMS is a long-run equilibrium model. By definition, the NEMS analysis projects the level of domestic production and imports necessary to meet all demand requirements. As a result, the NEMS analysis reflects more aggressive investment behavior than that portrayed for individual refiners in the short-term analysis.

The NEMS analysis reflects the "80/20" rule, which requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100 percent requirement for ULSD after June 2010. Because each model region acts as a single unit, the provision of the ULSD Rule allowing small refiners, which account for about 5 percent of current highway diesel production, to delay investment until June 2010 is not modeled explicitly. However, the production requirements are adjusted downward by 4 percent to reflect an assumption that most small refiners will choose to delay investment.[113]

The requirement for 80 percent ULSD is not phased in and begins on June 1, 2006. Therefore, the full market impact of the requirement can be expected to occur at that time. Because NEMS is an annual average model, the full economic impact of the 80/20 rule cannot be seen until 2007. In the same manner, projections for 2011 represent the first full year of 100 percent ULSD compliance. The results for 2010 reflect a partial year at the 80 percent requirement and a partial year at the 100 percent requirement. For the purpose of assessing the market impacts of the new ULSD requirements, 2007 will be discussed as the first full year of the 80/20 requirement, and 2011 will be discussed as the 100 percent requirement.

The House Committee on Science requested that, if practical, the EIA analysis use the same assumptions as those used by the U.S. Environmental Protection Agency (EPA) in its Regulatory Impact Analysis (RIA). The assumptions are compared in Table 13. The Regulation case for this study is based on the following assumptions:

- Highway diesel at the refinery gate will contain a maximum of 7 parts per million (ppm) sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel somewhat below 10 ppm in order to allow for contamination during the distribution process. The EPA assumed in its RIA that refineries would produce highway diesel at 7 ppm.

- The capital costs for the distillate hydrotreaters reflected in NEMS are $1,331 per barrel per day for a notional 25,000 barrel per day unit that processes low-sulfur feed streams with incidental dearomatization, and $1,849 per barrel per day for a second, 10,000 barrel per day unit that processes higher sulfur feed streams with greater aromatics improvement. A range of capital costs from a number of other studies is provided in Chapter 7. Because of differences in methodology, the sets of capital costs are not directly comparable. For instance, the EPA estimated the capital cost for a new distillate hydrotreater to range from $1,240 per barrel per day to $1,680 per barrel per day, but those estimates

[113]In its Regulatory Impact Analysis, the U.S. Environmental Protection Agency included investment by small refineries in cost estimates for full compliance but not for the transition period. See U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000).

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Table 13. Comparison of EIA and EPA Assumptions

Parameter	EPA	EIA	Sensitivity Analyzed
Sulfur Content at Refinery	7 ppm	7 ppm	None
Capital Costs for New Diesel Hydrotreaters	$1,240-$1,680 per barrel per day[a]	$1,331-$1,849 per barrel per day[b]	$1,655-$2,493 per barrel per day[b]
Percent of Production from Revamped Equipment	80 percent	80 percent	66.7 percent
Total Percentage of Downgraded ULSD	4.4 percent total	4.4 percent total	10 percent total
Revenue Loss Associated with Downgrade	0.2 to 0.3 cents per gallon for all highway diesel	0.2 to 0.3 cents per gallon ULSD based on model results	0.7 cents per gallon ULSD based on model results for 10 percent downgrade
Capital Cost for Distributing Two Highway Diesels (Excluding Above Revenue Loss)	0.7 cents per gallon through 2010	0.7 cents per gallon through 2010	None
Lubricity Additives	0.2 cents per gallon	0.2 cents per gallon	None
Loss of Energy Content	0 percent	0.5 percent	1.8 percent
Yield Loss	1.3 percent yield loss (weight) at a cost of 0.1 to 0.2 cents per gallon	Variable model result (about 1.5 percent by volume)	Variable model result (about 1.5 percent by volume)
Loss of Fuel Efficiency	None	None	4 percent loss starting in 2010, phased out by 2015
Change in Non-Road Diesel Standards	None	None	None
Change in Other Highway Diesel Properties	None	None	None
Import Availability	Not studied	Same as reference	No imports
Return on Investment	7% before tax (estimated 5.2% after tax)	5.2% after tax	10% after tax

[a]The low end of the range is for straight-run distillate; the high end is for light cycle oil.
[b]The low end of the range is for units processing low-sulfur feed with incidental dearomatization; the high end is for higher sulfur feeds with greater aromatics improvement.
Sources: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), and Energy Information Administration, Office of Integrated Analysis and Forecasting.

are associated with units processing 100 percent straight-run distillate and 100 percent light cycle oil, respectively.[114]

- Revamping (retrofitting) existing units to produce ULSD will be undertaken by refineries representing 80 percent of highway diesel production; the remaining refineries will build new units. Other analyses have assumed 60 percent revamps and 40 percent new builds, but the assumption of 80 percent revamps and 20 percent new units was used in the EPA's RIA. The capital cost of a revamp is assumed to be 50 percent of the cost of new equipment, which is consistent with the EPA analysis.

- The total amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 4.4 percent, an increase of 2.2 percent from the reference case. This assumption is based on the EPA's assessment that 2.2 percent of diesel fuel is currently downgraded and its assumption that the amount of downgrade will double with the new Rule. This downgrade assumption is associated with considerable uncertainty, because EPA's estimate of current downgrade was not based on a scientific survey. The EPA's estimation methodology was based on a survey by the Association of Oil Pipelines, in which six respondents provided estimates of the current diesel fuel downgrade, ranging from 0.2 percent to 10.2 percent.

- The costs associated with ULSD distribution are based in part on EPA assumptions and in part on NEMS results. This analysis uses the EPA's capital cost estimate of 0.7 cents per gallon for additional storage tanks to handle ULSD during the transition period. The capital expenditures are assumed to be fully amortized during the transition period. The ULSD Rule is assumed to increase the operating costs for distribution by 0.2 cents per gallon over the entire period. In addition, the EPA estimated a revenue loss of 0.2 to 0.3 cents per gallon for all highway diesel as a result of product downgrades. For this

[114]U.S Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Table V.C-9.

analysis, the revenue loss estimate is based on NEMS model results, at 0.3 cents per gallon of ULSD during the transition period and 0.2 cents per gallon after 2010.

- A cost of 0.2 cents per gallon is assumed for the addition of lubricity additives, consistent with estimates by the EPA and with industry analyses. Lubricity additives are needed to compensate for the reduction of aromatics and high-molecular-weight hydrocarbons stripped away by the severe hydrotreating used in the desulfurization process.

- The energy content of ULSD is assumed to decline by 0.5 percent, because undercutting and severe desulfurization will result in a lighter stream composition than that for 500 ppm diesel. The EPA's analysis made no explicit adjustment to the energy content of diesel fuel but estimated a cost associated with a 1.3-percent (by weight) loss of yield. In the NEMS analysis, the yield loss is a variable model result (generally around 1.5 percent by volume). The National Petrochemical and Refining Association (NPRA) quoted a range of 1 to 4 percent energy loss in comments to the rulemaking docket. NPRA also estimated a yield loss of 1 to 5 percent.

- In accordance with the EPA's RIA, changes to engine after-treatment devices are assumed to result in no loss of fuel efficiency. Discussions with some engine and emission control technology manufacturers indicated considerable uncertainty about this assumption.

- No change in the sulfur level of non-road diesel is assumed. The EPA analysis of ULSD reflects no change in non-road standards, although the EPA is in the process of promulgating "Tier 3" non-road engine emission limits around 2005 or 2006, which are expected to be linked to sulfur reduction for non-road diesel fuel.[115] The level of sulfur reduction required for Tier 3 vehicles is highly uncertain because of the diversity of the non-road market.

- No changes to other highway diesel specifications, such as aromatics or cetane, are assumed. Some refiners anticipate changes to these parameters in the future because of their relationship to emissions of particulate matter (PM). The State of California already limits aromatics to 10 percent by volume, which is reflected in this analysis. Proposals for similar requirements in other States are not included.

- Imports of diesel meeting the new ULSD standard are assumed to be available to U.S. markets, but the level of imports relative to the level of product supplied by refineries in the United States is a model result. Refineries in Canada, Northern Europe, and the Caribbean Basin (including Venezuela) are assumed to make upgrades to produce diesel fuel meeting the 15 ppm sulfur cap for 2006. Canada is moving forward with plans to harmonize with diesel regulations in the United States. European refiners will reduce diesel sulfur to 50 ppm for a new European standard in 2005. Some isolated European production of diesel meeting the ULSD standard is assumed, due to tax incentives for 10 ppm diesel in some markets.[116] In order to divert ULSD from European markets, prices in the United States would have to exceed the tax incentives plus shipping costs. In 2000 less than 5 percent of U.S. imports of highway diesel came from Europe.

- In accordance with the EPA's RIA, the before-tax rate of return on investment is assumed to be 7 percent. Between 1977 and 1999 the combined before-tax return on investment for refiners and marketers averaged 7 percent, which is equivalent to a 5.2-percent after-tax rate.[117] Because NEMS operates on an after-tax basis, the 5.2-percent rate is used in the model. Most of the studies compared in Chapter 7 assumed a 10-percent after-tax return on investment.

The Committee indicated that this analysis was to be as consistent as possible with the assumptions underlying the EPA's RIA, and that sensitivity analysis should be provided for assumptions that diverge significantly from those in other studies or from expectations of industry experts.[118] In addition to the Regulation case, this report provides sensitivity analyses for five assumptions associated with a greater uncertainty, for a Severe case that combines the assumptions of the five individual sensitivities, for a No Imports case, and for a 10% Return on Investment case:

- In the Higher Capital Cost case, the capital cost of the first notional hydrotreater is 24 percent higher than in the Regulation case, and the capital cost of the second notional unit is 33 percent higher.[119]

- In the 2/3 Revamp case, two-thirds of upgrades at refineries are assumed to be accomplished by retrofitting existing equipment and one-third by construction of new units. With the exception of the

[115] U.S. Environmental Protection Agency, *Reducing Air Pollution from Non-road Engines*, EPA420-F-00-048 (Washington, DC, November 2000), p. 3

[116] Germany and the United Kingdom have proposed tax incentives for sales of 10 ppm diesel

[117] Based on financial information from Form EIA-28 (Financial Reporting System)

[118] EIA did not assess the validity of these asumptions.

[119] The capital costs used in this case are based on recent work by EnSys, with revisions based on correspondence with Mr. Martin Tallett, April 23, 2001

EPA, all other cost analyses for ULSD have used an assumption of 60 percent revamps and 40 percent new units. The two-thirds revamp assumption was developed from EIA's individual refinery analysis (see Chapter 5 and Appendix D).

- In the 10% Downgrade case, a total of 10 percent of the 15 ppm diesel is assumed to be downgraded to a lower value product because of contamination with higher sulfur products in the distribution system. Before 2010 the contaminated product is assumed to be downgraded to 500 ppm highway diesel and does not result in additional production of 15 ppm highway diesel. After 2010, when all highway diesel must meet the 15 ppm sulfur standard, refineries must produce an extra 7.8 percent of highway diesel above the reference case level, which will be sold as non-road diesel or heating oil. The EPA assumption of 4.4 percent total downgrade after the ULSD Rule takes effect in June 2006 (2.2 percent higher than in the reference case) is on the low end of downgrade estimates, which range up to 17.5 percent by Turner Mason.
- In the 4% Efficiency Loss case, manufacturers are assumed to meet the emissions requirements by installing after-treatment technology on new vehicles beginning in 2010, resulting in a 4-percent loss of fuel efficiency. The loss in new vehicle efficiency is assumed to be fully phased out by 2015 as a result of technological improvements.[120]
- In the 1.8% Energy Loss case, a greater loss of energy content is assumed than in the Regulation case, which assumed a 0.5-percent loss. The loss of energy content is associated with more severe undercutting and desulfurization due to heavier crude oil inputs.[121]
- The Severe case combines the assumptions of the four sensitivity cases above. This scenario is more in line with the assumptions used by alternative studies related to ULSD than with the EPA's RIA.
- The No Imports case assumes that no foreign imports of ULSD will be available. This assumption is not included in the Severe case because it is considered to be relatively unlikely. The greatest uncertainty for import availability is likely to occur in the early years of the program because foreign refiners may delay investment until the market outlook for ULSD is more certain. Thus far, only Canada has announced its intent to align with the final U.S. leve' and timing for reducing sulfur in highway diese. fuel.[122] Environment Canada expects to launch a public consultation process in the next few months to facilitate the rulemaking, which is similar to the U.S. ULSD Rule while taking into account issues unique to the Canadian market.[123]
- The 10% Return on Investment case uses the after-tax rate of return assumed by most other studies (10 percent), which is higher than the 5.2-percent after-tax rate used in the Regulation and other sensitivities, consistent with the EPA's assumption.

Although the assumption of non-road diesel sulfur content is also highly uncertain, a sensitivity analysis would have required significant changes to the model structure and was not within the scope of this study. Sensitivity analysis of other diesel properties was also beyond the scope of the study.

Results

Discussions of all results are framed in terms of changes from the reference case. In the Regulation case and in all the sensitivity cases, projections for 2007 reflect the first full year of the program at 80 percent ULSD and 20 percent 500 ppm highway diesel, and 2011 reflects the firs full year of 100 percent ULSD. During the years requiring 80 percent ULSD, the reference case and sensitivity cases project that the greatest price increase will occur in 2007, because all investment for compliance with the "80/20" provision of the ULSD Rule must be met by that time. Similarly, a second peak in marginal prices is projected in 2011, because all investment for full compliance with the Rule must be in place by that time. Year-to-year variations in marginal prices can reflect differences in levels of demand for diesel and other products, oil price projections, the economics of domestic production versus imports, and other factors.

In the reference case, demand for transportation distillate (highway diesel) is projected to increase by 2.5 percent per year from 1999 to 2015. In the Regulation case, highway diesel demand is projected to grow at a slightly higher rate of 2.6 percent per year for the same period, largely due to the 2.2 percent additional (4.4 percent total) downgrades of highway diesel in the distribution

[120]This assumption is based on interviews with engine and technology manufacturers. Although this case reflects a scenario in which losses in efficiency from emission contol are not overcome by new technology, the considerable time available for research and development may provide government and industry ample time to resolve the fuel efficiency loss issues associated with advanced emission control technologies.

[121]The National Petrochemical and Refining Association provided data indicating that energy loss may be greater than assumed by the EPA. Letter from Terrence S. Higgins to James M. Kendell, February 8, 2001.

[122]Public Works and Government Services Canada, *Canada Gazette*, Vol. 135, No. 7 (February 17, 2001), p. 454.

[123]Maureen Monaghan, Natural Resources Canada, "Canadian Sulfur Standards for Gasoline and Diesel Sulfur," presentation to the U.S. Department of Energy (March 12, 2001).

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system. In other words, the additional downgrades must be offset by more ULSD production after 2010. The effect of downgrades is more pronounced in the 10% Downgrade case and the Severe case, where highway diesel demand is projected to increase by 2.9 percent and 3.1 percent per year, respectively, from 1999 to 2015.

Regulation Case

In the Regulation case, cumulative investment in distillate hydrotreating and hydrogen units is projected to be $4.2 billion higher than projected in the reference case in 2007 and $6.3 billion higher in 2011, when upgrades for meeting full compliance with the ULSD Rule will be complete (Table 14). In the early part of the transition period, upgrades for making ULSD may be constrained by specialized workforce and manufacturing limitations and access to capital, all of which will be in competition with projects for meeting the requirements for low-sulfur gasoline (see Chapter 3). The projected $2.1 billion in investment between 2007 and 2011 reflects expenditures for meeting expectations of growing demand for highway diesel, in addition to full compliance with the Rule. After 2011, incremental upgrades to meet future distillate demand are projected to continue, resulting in another $0.5 billion of investment in desulfurization equipment by 2015.

The Regulation case results in an increase in the marginal annual pump price for ULSD of 6.5 to 7.2 cents per gallon between 2007 and 2011 (Table 15). The peak differential is projected to occur in 2011, when all refiners must produce 100 percent ULSD. The projected differential declines after 2011, reaching 5.1 cents per gallon in 2015. About 0.7 cents of this decline is the result of no longer needing to include EPA's estimate of additional capital investments for distribution and storage of a second highway diesel fuel during the transition period. A drop in capital expenses for distribution systems occurs after 2010 as a reflection of the EPA's assumption that these investments will be fully amortized during the transition period. The remainder of the drop in the post-2011 differential occurs because refineries are expected to have completed the upgrades necessary for full compliance, and to be making incremental improvements that will make ULSD production less challenging. A similar decline in the price differential also occurs in all the sensitivity cases.

Through 2010, the Regulation case projections for highway diesel consumption exceed the reference case levels by up to 10,000 barrels per day, which can be attributed to the assumption of 0.5 percent loss in energy content. In 2011, the differential in consumption increases to 83,000 barrels per day, due mostly to the downgrade of 2.2 percent of ULSD to lower value non-road markets.

In a refinery, the impact of a change in the makeup or production level of a product can filter through to other

Table 14. Variation from Reference Case Projections of Cumulative Capital Expenditures for Hydrogen and Distillate Hydrotreating Units in EIA Sensitivity Cases, 2007, 2010, and 2015
(Billion 1999 Dollars)

Analysis Case	2007	2010	2015
Regulation	4.2	6.3	6.8
Higher Capital Cost	5.4	7.8	8.8
2/3 Revamp	4.6	6.9	7.6
10% Downgrade	4.2	6.7	7.3
4% Efficiency Loss	4.2	6.3	6.9
1.8% Energy Loss	4.2	6.3	6.9
Severe	5.9	9.3	10.5
No Imports	4.4	6.5	7.0

Source: National Energy Modeling System, runs DSUREF.D043001E, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A and DSU7IMP0.D043001A.

products, because it changes the mix of total refinery production. The ULSD Rule is projected to result in slightly lower yields of higher sulfur distillate used for non-road and heating purposes, because its production is replaced by ULSD that is produced by refineries but is downgraded to higher sulfur products in the distribution system. The availability of the downgraded ULSD reduces the projected prices for high-sulfur distillate by about 1 cent per gallon relative to the reference case. The analysis revealed no clear trends for other distillate products as a result of the ULSD Rule.

Higher Capital Cost Case

Because of limited experience in producing diesel containing less than 10 ppm sulfur, the capital costs for hydrotreaters able to mass produce ULSD are uncertain. The Higher Capital Cost case results in refinery investment for hydrogen and distillate hydrotreating units totaling $5.4 billion in 2007, which is $1.2 billion above the Regulation case level. By 2011 the Higher Capital Cost case is projected to require $7.8 billion of investment, $1.5 billion more than in the Regulation case. The higher investment costs translate to a higher projected price path for ULSD. Relative to the reference case, price differentials are projected to range from 7.5 to 7.8 cents per gallon between 2007 to 2010, peaking at 8.1 cents per gallon in 2011, the first full year of full compliance. These prices are 0.8 cents per gallon higher on average than those in the Regulation case.

2/3 Revamp Case

The 2/3 Revamp case results in a higher projected price path for ULSD, with price differentials ranging from 6.9 to 7.6 cents per gallon higher than in the reference case from 2007 to 2011. Prices are generally higher than in the Regulation case, with the differential between the two cases at its widest in 2011 at 0.4 cents per gallon. The 2/3

Revamp case reflects greater reliance on new equipment than in the Regulation case, resulting in an additional $600 million of investment for full compliance in 2011.

10% Downgrade Case

The 10% Downgrade case reflects a net downgrade increase of 7.8 percent over the reference case and 5.6 percent over the Regulation case. Total highway diesel consumption increases by up to 10,000 barrels per day in the transition period in both the 10% Downgrade case and the Regulation case. After 2010, the 10% Downgrade case results in an additional 289,000 barrels per day of highway diesel consumption, compared with an additional 83,000 barrels per day in the Regulation case. The greatest impact from downgrade in either the 10% Downgrade or Regulation case on refiners and consumers occurs after 2011, because until that time the contaminated product can be downgraded to 500 ppm highway diesel with no net increase in highway diesel production. Because all highway diesel supplied must meet the 15 ppm sulfur cap in June 2010, ULSD exceeding 15 ppm sulfur at some point in the distribution system must be downgraded to non-road markets and must be offset by additional ULSD production after 2010. This means that refiners must produce 212,000 barrels per day more ULSD after 2010 than in the Regulation case, which translates to an additional $500 million of investment by 2015.

Aside from the impacts on ULSD on demand and refinery investment, the 10% Downgrade case has implications for the economics of pipelines and marketers, because they incur a revenue loss when a portion of the ULSD going into the system comes out of the system as a lower value product. Table 16 shows the costs associated with ULSD distribution in the Regulation and 10% Downgrade cases. The capital costs, which are assumed to be the same in both cases, reflect additional infrastructure required for carrying a second highway diesel product during the transition period. The estimate for capital expenditures was taken from the EPA's RIA and is fully amortized over the transition period. The additional annual diesel fuel distribution costs in the Regulation case differ slightly from the EPA estimates (see Table 26 in Chapter 7), because different revenue losses associated with product downgrade are assumed.

Table 15. Variations from Reference Case Projections in the Regulation and Sensitivity Analysis Cases, 2007-2015

Analysis Case	2007	2008	2009	2010	2011	2015	2007-2010 Average	2011-2015 Average
Difference Between End-Use Prices of ULSD and 500 ppm Diesel (1999 Cents per Gallon)[a]								
Regulation	7.0	6.7	6.5	6.8	7.2	5.1	6.8	5.4
Higher Capital Cost	7.8	7.6	7.5	7.6	8.1	5.8	7.6	6.2
2/3 Revamp	7.3	6.9	6.9	7.1	7.6	5.4	7.1	5.7
10% Downgrade	7.4	7.1	6.8	7.2	9.1	5.7	7.2	6.4
4% Efficiency Loss	7.0	6.7	6.5	6.9	7.3	5.3	6.8	5.7
1.8% Energy Loss	7.3	7.0	6.6	6.9	7.4	5.2	7.0	5.5
Severe	8.8	8.4	8.4	8.6	10.7	6.8	8.6	7.4
No Imports	8.6	8.1	7.8	8.0	8.8	6.2	8.1	6.8
Total Highway Diesel Fuel Consumption (Thousand Barrels per Day)								
Regulation	10	10	8	8	83	85	9	83
Higher Capital Cost	10	9	8	7	82	83	9	82
2/3 Revamp	10	10	8	8	82	84	9	82
10% Downgrade	10	10	8	8	289	303	9	295
4% Efficiency Loss	10	10	8	19	103	108	12	107
1.8% Energy Loss	41	41	39	47	127	131	42	128
Severe	41	40	39	57	355	374	44	366
No Imports	10	9	7	7	81	83	8	81
Total Imports of Highway Diesel Fuel (Thousand Barrels per Day)								
Regulation	-36	-1	-1	0	0	0	-10	0
Higher Capital Cost	-36	-1	-1	0	0	0	-10	0
2/3 Revamp	-36	-1	-1	0	0	0	-10	0
10% Downgrade	-36	-1	-1	0	0	0	-10	0
4% Efficiency Loss	-36	-1	-1	0	0	0	-10	0
1.8% Energy Loss	-36	-1	-1	0	0	0	-10	0
Severe	-36	-1	-1	0	0	0	-10	0
No Imports	-120	-125	-125	-125	-125	-125	-124	-125

[a]End-use prices include marginal refinery gate prices, distribution costs, and Federal and State taxes but exclude county and local taxes.

Source: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, and DSU7IMP0.D043001A.

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4% Efficiency Loss Case

The 4% Efficiency Loss case reflects an expectation, by some engine and emission technology manufacturers, that emission requirements for new heavy-duty vehicles in 2010 will be met by installing after-treatment technology, which could result in a 4-percent loss of fuel efficiency. Technological improvements are assumed to fully offset the loss in fuel efficiency of new vehicles by 2015.[124] The combined impact of the ULSD requirement and less efficient new vehicles results in 19,000 barrels per day of additional highway diesel consumption in 2010 and 107,000 barrels per day in 2011 through 2015. The introduction of less fuel-efficient vehicles accounts for 11,000 barrels per day of the additional demand in 2010 and 24,000 barrels per day of demand after 2010. Refiners are projected to invest an additional $100 million dollars through 2015 relative to the Regulation case to provide for the slightly higher diesel demand.

The additional demand for highway diesel results in prices that are 5.7 cents per gallon above reference case prices on average between 2011 and 2015. This differential is 0.3 cents higher than when no fuel efficiency loss is assumed. Owners of vehicles purchased between 2010 and 2015 would see the greatest impact under this case, because diesel vehicles of that vintage would consume relatively more diesel fuel.

1.8% Energy Loss Case

Due to changes in refinery processing, ULSD is expected to have slightly less energy content than 500 ppm diesel. The 1.8% Energy Loss case reflects a greater loss of energy content than the Regulation case, which assumes a 0.5-percent loss per barrel. This case results in an average increase in ULSD consumption of 42,000 barrels per day between 2007 and 2010. Due to the 100 percent ULSD requirement, the impact of the lower energy content is greatest after 2010 when it widens to 128,000 barrels per day. Relative to the Regulation case, the 1.8% Energy Loss case results in an average of 33,000 barrels per day of additional demand through 2010 and 45,000 barrels per day after full compliance. This additional demand does not change refinery investment patterns relative to the Regulation case, because it can be provided through higher utilization rates.

The price differentials from the reference case average 7.0 cents per gallon between 2007 and 2010 and 5.5 cents per gallon between 2011 and 2015. In anticipation of higher demand, refineries are expected to build slightly more capacity in the transition period than they would in the Regulation case. Because of the slightly different investment pattern, prices in the 1.8% Energy Loss case are 0.2 cents per gallon higher than in the Regulation case on average through 2010 and comparable to Regulation case prices after 2010.

Severe Case

In the Severe case, the ULSD requirement in combination with the five sensitivity assumptions results in an average of 44,000 barrels per day of additional highway diesel consumption between 2007 and 2010 and an average of 366,000 barrels per day of additional demand between 2011 and 2015. The ULSD regulation by itself accounts for about 9,000 barrels per day of the additional consumption through 2010 and about 83,000 barrels per day after 2010. The combined effect of the five

Table 16. Variations from Reference Case Projections of Fuel Distribution Costs in the Regulation and 10% Downgrade Cases
(1999 Cents per Gallon)

Analysis Case and Cost Component	Average Annual Cost. June 2006 - June 2010	Average Annual Cost After June 1, 2010
Regulation		
Total	1.2[a]	0.4[a]
Capital Costs	0.7	0.0
Operating Costs	0.2	0.0
Downgrade Revenue Loss	0.3	0.2
10% Downgrade		
Total	1.6	0.9
Capital Costs	0.7	[illegible]
Operating Costs	0.2	0.2
Downgrade Revenue Loss	0.7	0.7

[a] The additional annual diesel fuel distribution costs in the Regulation case differ slightly from the EPA estimates (see Table 26 in Chapter 7) because different revenue losses associated with product downgrade are assumed.

Sources: **Capital Costs and Operating Costs**: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. Operating Costs include operating, existing mix, transmix, and testing cost estimates. **Downgrade Revenue Loss**: Energy Information Administration, Office of Integrated Analysis and Forecasting, based on projected price differentials for ULSD versus 500 ppm diesel.

[124] This assumption is based on interviews with engine and technology manufacturers.

assumptions raises demand beyond that in the Regulation case by about 35,000 barrels per day through 2010 and by about 283,000 barrels per day after 2010. The higher downgrade assumption accounts for about 212,000 barrels of the additional demand after 2010. The Severe case results in a projected increase in refinery investments for hydrogen and distillate hydrotreating totaling $9.3 billion in 2011, $3.0 billion more than in the Regulation case. Higher demand in the Severe case results in marginal prices 1.7 to 3.5 cents per gallon above those in the Regulation case.

No Imports Case

In 1999, 87 percent of all imports of highway diesel went to PADD I (the East Coast), which is less self-sufficient than other regions in terms of refinery production. The East Coast is expected to continue to be the major market for imported highway diesel; however, a slight reduction in imports is projected under the ULSD Rule, because it is more economical for domestic refiners to provide the last barrel supplied. The No Imports case assumes that imports of highway diesel fuel are zero and, therefore, 120,000 to 125,000 barrels per day lower than projected in the reference case. The lack of imports means that domestic refineries must produce that much more ULSD. During the transition years, prices in the No Imports case are only slightly lower than in the Severe case, indicating the sensitivity of the market to imports. The requirement for more production results in marginal prices 1.1 to 1.6 cents per gallon higher than in the Regulation case. The higher prices in the No Imports case result in a slight dampening of demand, by up to 2,000 barrels on average when compared to the Regulation case. When imports of ULSD are not available, refineries are projected to meet the additional ULSD requirement by investing an additional $200 million in desulfurization equipment through 2015, and by reducing jet fuel production and importing more jet fuel. More ULSD is also shipped from PADDs II-IV to PADD I to compensate for the lack of imports.

10% Return On Investment Case

This case assumes that refiners will realize a higher rate of return than is assumed in the Regulation case and in all the other sensitivity cases for this analysis, which assume a 5.2-percent after-tax return on investment. Because the 10% Return on Investment case must be compared with an alternative reference case that uses a consistent rate of return, the projected price differentials are presented separately from those for the cases that are compared with the reference case (with a 5.2-percent after-tax rate (Table 17). The resulting price differentials range from 7.5 to 8.0 cents per gallon between 2007 and 2011 and are 0.9 cents per gallon higher on average than when the 5.2-percent after-tax rate is assumed. The different return on investment affects the payback of investment but does not affect the level of investment.

Regional Variations in Refining Costs

Differences between regional refinery gate prices in the analysis cases relative to those in the reference case reflect variations in the marginal costs of producing ULSD between regions (Table 18). The cost curve analysis described in Chapter 5 indicates that PADD IV, which contains relatively small refineries, can be expected to be the highest cost region; however, these costs are obscured by the aggregate model representation in NEMS. The Petroleum Market Module provides refining costs for three separate regions: PADD I (the East Coast), PADDs II-IV aggregated (mid-U.S.), and PADD V (the West Coast). In the transition years of the Regulation case, regional refining costs (excluding distribution costs) range from an average of 4.8 cents per gallon in PADD V to 5.3 cents per gallon in the other regions, with an average U.S. cost of 5.2 cents per gallon.

The relative patterns of regional costs during the transition period are similar in all the sensitivity cases, with PADD I as the highest cost region of the three NEMS regions, PADD V as the lowest cost region, and PADDs II-IV (and the U.S. average) falling in between. The relatively high ULSD production cost in PADD IV is masked in the mid-term analysis, because PADD IV is aggregated both with PADD II and with the largest and lowest cost refining region, PADD III. Average marginal refining costs generally are expected to fall by about 0.5 to 0.8 cents per gallon after 2011, as refineries make incremental improvements to meet incremental increases in demand more efficiently.

Conclusion

The ULSD Rule is projected to require total refinery investments ranging from $6.3 billion in the Regulation case to $9.3 billion in the Severe case, resulting in highway diesel fuel price increases that range from 6.5 to 10.7

Table 17. Variations from Alternative Reference Case Projections in the 10% Return on Investment Case, 2007-2015

Year	Difference Between End-Use Prices of ULSD and 500 ppm Diesel (1999 Cents per Gallon)[a]
2007	7.9
2008	7.5
2009	7.6
2010	7.7
2011	8.0
2015	5.7
2007-2010 Average	7.7
2011-2015 Average	6.0

[a]End-use prices include marginal refinery gate prices, distribution costs, and Federal and State taxes but exclude county and local taxes.
Source: NEMS runs DSUREF10.D043001A and DSU7PPM10.D043001A.

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cents per gallon between 2007 and 2011. Because this analysis is based on results from a long-run equilibrium model, it does not capture the uncertainty of supply discussed in Chapter 5. The NEMS analysis reflects more aggressive investment than is portrayed for individual refiners in the short-term analysis. In the Regulation case, which uses many of the EPA's assumptions, prices are projected to increase by 6.5 to 7.2 cents per gallon between 2007 and 2011. The widest price differential—10.7 cents per gallon in 2011—is projected in the Severe case, which is based on assumptions more consistent with industry views. This peak price differential is associated with a requirement for additional ULSD supplies of 272,000 barrels per day above demand levels in the Regulation case, of which 206,000 barrels per day results from the 10-percent downgrade assumption.

Because NEMS is a long-run equilibrium model, it cannot address short-term supply issues; however, the No Imports case does provide some implications for short-term supply. When no availability of ULSD grade imports is assumed, the marginal price of ULSD is projected to exceed prices reflecting access to imports by about 1.2 to 1.6 cents per gallon between 2007 and 2011.

Table 18. Variations from Reference Case Projections of ULSD Marginal Refinery Gate Prices by Region in the Regulation and Sensitivity Analysis Cases, 2007-2015
(1999 Cents per Gallon)

Analysis Case and Producing Region	2007-2010 Average	2011-2015 Average	Analysis Case and Producing Region	2007-2010 Average	2011-2015 Average
Regulation			**4% Efficiency Loss** . . .		
U.S. Average	5.2	4.7	U.S. Average	5.2	5.1
PADD I	5.3	4.8	PADD I	5.3	5.3
PADDs II-IV	5.3	4.8	PADDs II-IV	5.3	5.2
PADD V	4.8	4.3	PADD V	4.8	4.5
Higher Capital Cost			**1.8% Energy Loss**		
U.S. Average	6.4	5.2	U.S. Average	5.5	4.8
PADD I	6.6	5.5	PADD I	5.6	5.3
PADDs II-IV	6.6	5.3	PADDs II-IV	5.6	4.9
PADD V	6.4	4.9	PADD V	5.2	4.4
2/3 Revamp			**Severe**		
U.S. Average	5.7	4.9	U.S. Average	7.0	6.4
PADD I	6.0	5.0	PADD I	7.4	6.9
PADDs II-IV	6.0	5.0	PADDs II-IV	7.4	6.3
PADD V	5.0	4.5	PADD V	5.9	5.2
10% Downgrade			**No Imports**		
U.S. Average	5.2	5.2	U.S. Average	6.6	[illegible]
PADD I	5.3	5.4	PADD I	6.9	6.5
PADDs II-IV	5.3	5.3	PADDs II-IV	6.9	6.3
PADD V	4.8	4.7	PADD V	4.5	4.3

Source: NEMS runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DB[illegible].D043001A, DSU7TR[illegible].D043001A, DSU7ETU.D043001A, DSU7ALL.D050101A, and DSU7IMPC.D043001A.

7. Comparison of Studies on ULSD Production and Distribution

This chapter compares the methodology and results of the Energy Information Administration's (EIA's) analysis with those from a number of other studies related to ultra-low-sulfur diesel fuel (ULSD) supply and costs. Refinery costs and investments are compared with other estimates from studies by the U.S. Environmental Protection Agency (EPA), Mathpro, the National Petroleum Council (NPC), Charles River and Associates and Baker and O'Brien (CRA/BOB), EnSys Energy & Systems, Inc. (EnSys), and Argonne National Laboratory (ANL). EIA's estimates of distribution costs are compared with estimates from the EPA, ANL, and Turner, Mason and Company (TMC). A review of an analysis of alternative markets for diesel fuel components by Muse, Stancil and Company (MSC) is also provided. All cost estimates in this chapter have been converted to 1999 dollars.

Analyses of Refining Costs

The refining cost studies reviewed here represent a range of methodologies and assumptions. An understanding of some key terms is important to differentiating between the methodologies of the various studies. The studies were based on two general types of methodologies: a linear programming (LP) approach used by Mathpro, NPC, EnSys, DOE, and EIA; and a refinery-by-refinery approach used by CRA, EPA, and EIA. Within either approach, the studies used different methodologies and made different assumptions that make them difficult to compare. For instance, two different types of LP refinery models were used. The Mathpro analysis used an LP model of a "notional refinery" that represented an average refinery in a given region. In contrast, EnSys and EIA used refinery LP models that represented an aggregate refinery, or all the refineries in a region acting as one (Tables 19 and 20).

Costs estimated by the different studies are not easy to compare, because differences in estimation methodologies make them conceptually different. Both "average" and "marginal" costs can be based on LP models that operate as a single firm, or estimated from analysis of individual refineries. In general, marginal cost estimates that represent the cost of the last barrel of required supply can be seen as estimates of market prices. Much of the variation in investment and cost estimates reflects different assumptions about the cost of technologies; return on investment; the extent to which refiners will modify existing equipment or build entirely new hydrotreaters; the cost and quantity of additional hydrogen required; the extent to which some refineries may reduce highway diesel production; and the amount of highway diesel downgraded due to fuel contamination during distribution.

In EIA's refinery-by-refinery analysis (cost curves), the increased cost of producing ULSD in 2006 is estimated to be between 5.4 and 6.8 cents per gallon. Using the National Energy Modeling System (NEMS) Petroleum Market Module (PMM), the increased cost of producing ULSD is estimated to be between 4.7 and 7.3 cents per gallon from 2007 to 2010 and between 6.5 and 9.2 cents per gallon in 2011.[125] The estimated additional production costs are associated with expected increases in average marginal price increases at the pump ranging from 6.5 to 8.8 cents per gallon in the transition period and 7.2 to 10.7 cents per gallon in 2011. In the Regulation case, which uses many of the EPA's assumptions, prices are projected to increase by 6.5 to 7.2 cents per gallon between 2007 and 2011. The widest price differential—10.7 cents per gallon in 2011—is projected in the Severe case, which is based on assumptions more consistent with industry views.

For consistency with the EPA's analysis, EIA estimates are based on a 7-percent before-tax return on investment, which is estimated to equate to a 5.2-percent after-tax rate of return.[126] When a 10-percent after-tax rate of return, which was used in all the other analyses, is assumed; the refinery-by-refinery costs are about 0.6 to 1.2 cents per gallon higher than in the Regulation case, and the NEMS costs are about 0.8 to 1.1 cents per gallon higher than in the Regulation case.

[125] In the NEMS PMM projections, the U.S. price is the average of the marginal prices in the three model regions.

[126] According to financial information from Form EIA-28 (Financial Reporting System) refiners and marketers averaged a 7-percent before-tax return on investment between 1977 and 1999.

Table 19. Methodologies Used To Estimate ULSD Refining Costs

Author	Client	Date	Methodology
Mathpro	Engine Manufacturers Association	October 1999; updated August 2000	LP, notional refinery Original study: PADDs I-III average cost (aggregated) Updated study: average cost U.S. excluding California
EPA		December 2000	Refinery-by refinery analysis, average cost after credit trading
NPC	U.S. Department of Energy	June 2000	Adjusted Mathpro's LP results from original study, average cost
CRA/BOB	American Petroleum Institute	August 2000	Constructed cost curves using industry interviews, refinery-by-refinery analysis, marginal cost of PADDs I-III aggregated, PADD IV, PADD V, and U.S.
EnSys	U.S. Department of Energy	August 2000	LP, aggregate PADD III refinery, average cost by each quartile of production, marginal costs provided for one scenario
ANL	U.S. Department of Energy	November 2000	Estimated weighted average costs based on EnSys costs
EIA	U.S. House of Representatives, Committee on Science	April 2001	(1) LP: aggregate regional refineries, PADDs I, II-IV aggregate, and V; marginal cost (2) Cost curves based on individual refinery data

Sources: **EPA:** U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. **Mathpro:** Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000), Exhibit 8, Case 11. **NPC:** National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 3. **CRA/BOB:** Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000). **EnSys:** EnSys Energy & Systems, Inc. *Modeling impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000). **ANL:** M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000). **EIA:** Energy Information Administration, Office of Integrated Analysis and Forecasting (Chapters 5 and 6 of this report).

Table 20. Characteristics of ULSD Cost Studies

Study	LP Model	Based on LP Results	Refinery-by-Refinery	Year-by-Year	Single Period	Multi-Region Results	Average Cost	End-Use Prices	Market Equilibrium Prices	Supply / Demand Analysis
Mathpro	X				X	X	X			
EPA			X	2006, 2010		X	X	X		
NPC		X[a]			X		X			
CRA/BOB			X		X	X		X	Short-run	X
EnSys	X				X		X			
ANL		X[b]		2006-2015[c]			X	X		
EIA NEMS	X			2007-2015		X		X	Long-run	X
EIA Refinery by Refinery			X		X	X	X			X

[a]Uses Mathpro results.
[b]Uses EnSys results.
[c]Phase-in of 8 percent ULSD to 100 percent.

Sources: **EPA:** U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. **Mathpro:** Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000), Exhibit 8, Case 11. **NPC:** National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 3. **CRA/BOB:** Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000). **EnSys:** EnSys Energy & Systems, Inc. *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000). **ANL:** M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000). **EIA Refinery by Refinery:** Energy Information Administration, Office of Integrated Analysis and Forecasting (Chapter 5 of this report). **EIA NEMS:** National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, DSU7IMP0.D043001A, DSUREF10.D043001A, and DSU7PPM10.D043001A.

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EPA Analysis

The EPA analysis was conducted in support of the final rulemaking published in December 2000.[127] The EPA analysis used a refining cost spreadsheet that included refinery-specific estimates for meeting the new highway diesel standards and aggregated them to estimate fuel cost increases at the Petroleum Administration for Defense District (PADD) and national levels. The costs of meeting the final ULSD Rule were analyzed without including possible reductions in non-road diesel sulfur. The EPA estimated that the ULSD Rule would increase average national production and distribution costs by 5.4 cents per gallon of 15 ppm diesel (4.5 cents per gallon for all highway diesel) during the temporary compliance period (2006 to 2010).[128] The total cost after full compliance in June 2010 was estimated at 5.0 cents per gallon (Table 21).

The largest component of the costs estimated by the EPA was increased refining costs (4.1 cents per gallon for 15 ppm diesel and 3.3 cents per gallon for all highway diesel between 2006 and 2010; 4.3 cents per gallon after June 1, 2010). The cost estimate for the compliance period was adjusted downward to reflect credit trading, assuming that low-cost refineries trade with high-cost refineries at the cost of production. Cost estimates for PADD IV were 30 to 40 percent higher than costs in other PADDs. The refining costs discussed above were based on a 7-percent before-tax return on investment, but the EPA also provided costs based on a 6-percent and 10-percent after-tax rate of return. The cost estimates for a 6-percent after-tax rate of return were 0.1 cents per gallon higher than the full compliance cost calculated with the 7-percent before-tax rate, and the estimates for a 10-percent after-tax rate were 0.4 cents per gallon higher.[129]

In addition to increased refining costs, the EPA estimated that the addition of lubricity additives would cost approximately 0.2 cents per gallon, and distribution costs were estimated to add another 1.1 cents per gallon during the temporary compliance period and 0.5 cents per gallon after full compliance.[130] The analysis behind the distribution cost estimates is discussed below.

Increased refining costs were expected to result from capital investment of $3.9 billion to meet the 2006 requirements and another $1.4 billion to reach full compliance in 2010, for a total investment of $5.3 billion.[131] The EPA estimated that the average refinery would spend $43 million dollars in capital expenditures and an additional $7 million per year in operating costs.

The EPA assumed that, in order to meet the 15 ppm highway diesel requirement, refiners would need to produce 7 ppm diesel fuel on average. It was assumed that 80 percent of diesel refining capacity would meet the new standards by modifications to existing hydrotreaters and the other 20 percent by building new hydrotreaters. The analysis included cost estimates under two scenarios. The first scenario assumed that all refiners currently producing highway diesel fuel would continue to do so. The second scenario assumed that some refiners would increase their production of highway diesel while making up for lost production from refiners that would drop out of the market. The EPA did not provide analysis assuming a net loss of production, but indicated that, with the inclusion of the 80/20 and small refiner provisions, no supply problems were anticipated. The EPA also performed an analysis of engineering and construction requirements and concluded that these factors should not be a problem due to the temporary compliance provisions (see Chapter 3 for more discussion).

Table 21. EPA Estimates of Increased Costs To Meet the 15 ppm Highway Diesel Standard (1999 Cents per Gallon)

Period	Additional Refining	Lubricity Additive	Distribution[a]	Additional Distribution Tanks	Total Increase
Phase-in, 2006-2010	4.1	0.2	0.4	0.7	5.4
Fully Implemented Program, 2010	4.3	0.2	0.5	0.0	5.0

[a]Not including additional distribution tanks.

Source: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), p. V-103.

[127] U.S. Environmental Protection Agency, "Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Final Rule," *Federal Register*, 40 CFR Parts 69, 80, and 86 (January 18, 2001).

[128] Total cost per gallon of 15 ppm diesel is the sum of 4.1 cents per gallon refining cost and 1.1 cent per gallon distribution cost.

[129] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-106.

[130] Distribution costs include the capital cost of additional storage tanks, additional operating costs, yield losses, product downgrades, and testing costs.

[131] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-103, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf

Mathpro Analysis

In its original study for the Engine Manufacturers Association, Mathpro provided 5 sets of scenarios for 10 different combinations of heavy-duty, non-road, and light-duty diesel fuel standards. The scenarios were developed using a linear programming (LP) representation of a notional refinery in PADDs I through III.[132] The study was completed in October 1999 and reflected a range of uncertainty with regard to the eventual sulfur standard. The target sulfur level for highway diesel in the scenarios ranged from 150 ppm to 2 ppm. The scenarios also reflected varying assumptions about the ultimate sulfur level of non-road diesel, and about investment in upgrade (revamp) projects versus new (grassroots) projects. The scenarios resulted in an average increase in refining costs ranging from 2.5 to 9.0 cents per gallon for the 150 ppm and 2 ppm sulfur levels, respectively. The associated investment costs ranged between $0.8 billion and $3.9 billion for PADDs I through III.

In August 2000, Mathpro updated its analysis using the 15 ppm sulfur standard indicated in the June 2000 Notice of Proposed Rulemaking, assuming that the requirement would be met by producing diesel fuel with a pool average of 8 ppm or less.[133] The updated analysis provided estimates given three different assumptions about non-road diesel:

- Non-road diesel at current levels (3,500 ppm). This assumption most closely resembles the EIA and EPA cost analyses.
- Non-road diesel reduced to 350 ppm
- Non-road diesel reduced to 15 ppm.

For each of the non-road sulfur assumptions, the updated analysis provided five scenarios based on different investment and operating approaches by refineries:

- No Retrofitting-Inflexible, which requires only new unit investment
- No Retrofitting-Flexible, which requires only new unit investment but allows some flexibility in hydrocracking and jet fuel production
- Retrofitting-De-rate/Parallel, which allows modification of the existing desulfurization unit and building a parallel unit
- Retrofitting-Series, which allows expansion of the existing desulfurization unit by debottlenecking and adds a new unit in series
- Economies of Scale, which is similar to Retrofitting-Series but allows further economies of scale through inter-refinery processing arrangements.

The estimated increase in national average refining costs (excluding California) ranged between 4.0 and 7.6 cents per gallon and was associated with total investment costs between $1.8 billion and $3.3 billion (1999 dollars) over all of the non-road sulfur assumptions. Costs ranged from 4.5 to 7.1 cents per gallon and investments from $3.0 to $6.0 billion for the scenarios assuming current sulfur levels for non-road diesel (Table 22). The analysis assumed a 10-percent after-tax rate of return on investment. The scenarios with non-road diesel at 3,500 ppm were most similar to the EIA, EPA, and DOE analyses, and the scenario with non-road diesel at 350 ppm was more consistent with the CRA/BOB analysis. When non-road diesel was held at 3,500 ppm, the average cost of producing highway diesel increased by 7.1 cents per gallon in the No Retrofitting-Flexible case and by 4.5 cents per gallon in the Economies of Scale case.

Although the investment costs estimated by Mathpro were at least $195 million dollars higher when the sulfur limit for non-road diesel was assumed to decline to 350 ppm, the average costs were between 0.2 and 1.2 cents per gallon lower than in the scenarios assuming

Table 22. Mathpro Estimates of the Costs of Producing 15 ppm Highway Diesel, with Non-Road Diesel at 3.500 ppm Sulfur

Flexible	No Retrofit: Inflexible	No Retrofit: Flexible	Retrofit: De-rate	Retrofit: Series	Economies of Scale
Total Average U.S. Cost[a] (1999 Cents per Gallon)	6.8	7.1	6.7	4.6	4.5
Investment (Million 1999 Dollars)	5.950	5.900	5.370	3.330	3.040

[a]Excludes California.

Note: Costs have been converted to 1999 dollars from the 2000 dollars reported by Mathpro.

Source: Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000), Exhibit 8.

[132]Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000).

[133]Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD, August 2000).

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3,500 ppm non-road diesel. The lower average costs were the result of spreading the investments over a larger volume of product. The scenarios with non-road diesel sulfur capped at 15 ppm required the most investment and led to the highest costs. Relative to the 3,500 ppm non-road scenarios, the 15 ppm non-road scenarios required at least $1 billion more investment and resulted in average costs between 0.1 and 0.8 cents per gallon higher.

NPC Analysis

In its report, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels*, the NPC included estimates of meeting a 30 ppm sulfur standard.[134] The estimates were based on the 30 ppm scenarios included in Mathpro's original report for the Engine Manufacturers Association in October 1999. The NPC combined the cost estimates from the "no retrofitting-inflexibility" and the "retrofitting-series" cases assuming that at 30 ppm, most refiners would retrofit. The NPC also made adjustments to the Mathpro estimates to reflect alternative assumptions of refinery economics. NPC adjusted the vendor-supplied estimates used in the Mathpro model upward by a factor of 1.2 for investments and a factor of 1.15 for hydrogen consumption and other operating expenses. The vendor data were adjusted to account for a perceived tendency of vendors to quote overly optimistic cost and performance information. The NPC analysis estimated industry investment costs at $4.1 billion at a cost of 5.9 cents per gallon (1999 dollars) and assumed 50 percent revamped and 50 percent new units. The study indicated that a sulfur standard below 30 ppm would require greater reliance on new units, as opposed to retrofits, resulting in considerably higher investments.

The NPC analysis included a discussion of limitations on engineering and construction resources and, in contrast with the EPA analysis, concluded that the overlap with gasoline sulfur projects would result in delays in meeting the diesel standards. The study suggested that highway diesel supply shortfalls might occur if the standard were required before 2007 and that even more time would be required to meet a standard below 30 ppm.

(See Chapter 3 of this report for more detail on engineering and construction.)

CRA/BOB Analysis

In a study for the American Petroleum Institute, CRA/BOB developed refinery-specific cost estimates for every U.S. refinery, using the Prism refinery model.[135] The estimates and a survey of refiners intentions were used to construct a marginal cost curve that was used in an equilibrium supply and demand analysis. The initial supply and demand assumptions were from EIA's *Annual Energy Outlook 2000*. The supply curve was shifted according to the marginal cost analysis, and the demand curve was shifted based on an elasticity assumption. In contrast to all but the EIA offline analysis, the CRA/BOB study provided an analysis of a short-term supply and cost outlook.

The analysis projected a reduction in highway diesel production of 320,000 barrels per day, resulting in a supply shortfall. The EPA has estimated that 75 percent of the shortfall estimated by CRA/BOB resulted from the underlying assumption that an additional 10 percent of the highway diesel produced would be downgraded because of product degradation from distribution and storage.[136] In contrast, EIA and the EPA assumed an additional 2.2 percent of downgraded product, and TMC estimated that a total of 17.5 percent of ULSD would be downgraded.[137] The estimated increase in average refining cost was 6.7 cents per gallon to produce ULSD from 500 ppm diesel. The estimated increase in the marginal price of ULSD needed to balance supply and demand was between 14.7 and 48.9 cents per gallon, depending on the availability of imports.

The CRA/BOB analysis assumed that, in order to meet the 15 ppm standard, refiners would produce highway diesel at an average of 7 ppm.[138] The analysis also assumed that non-road diesel would be reduced to 350 ppm and jet fuel and heating oil sulfur would remain at 1999 levels. The cost estimates reflected an assumption that 40 percent of ULSD would be produced from new desulfurization units and 60 percent from revamped units, and that the return on investment would be 10 percent.

[134] National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), Chapter 3. Investment and cost estimates have been converted to 1999 dollars from 1998 dollars reported by NPC.

[135] Charles River Associates, Inc. and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000).

[136] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf

[137] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000), *Revised Supplement* (August 2000).

[138] Telephone conversation with Ray Ory of Baker and O'Brien, January 25, 2001.

EnSys Analysis

EnSys provided a set of cost estimates to the U.S. Department of Energy's Office of Policy, using an LP model that represents PADD III refiners in the aggregate.[139] The estimates reflected a 10-percent return on investment. Unlike the previously discussed studies, EnSys did not make an assumption of how many refiners would revamp units and how many would build new desulfurization units, but instead provided cost estimates for a refinery using revamps and cost estimates for a refinery building new units. The scenarios were also based on two sets of technologies: a conservative technology set and an optimistic technology set. In order to model a phase-in of the highway diesel standard, a series of cases were run assuming different percentages of highway diesel required to meet the new standard.

EnSys developed the scenarios discussed above for the production of highway diesel at various sulfur levels, ranging from 8 ppm to 30 ppm. The results of the 10 ppm scenarios are the focus of this discussion, because they were highlighted in the EnSys report and were provided in a more uniform manner. In general, the scenarios with diesel sulfur at 8 ppm were about 0.5 cent above the 10 ppm estimates. The average incremental cost estimates for producing 10 ppm diesel ranged from 4.4 to 6.0 cents per gallon for the first 50 percent of highway diesel produced at 10 ppm, 6.0 to 7.9 cents for the next 25 percent, and 7.6 to 10.1 cents per gallon for the final 25 percent of production. The lower estimate assumed that the product was produced by 100 percent revamped units; the higher estimate assumed 100 percent new units.

The cases assumed that 25, 50, 75, and 100 percent of highway diesel would be required to meet the 10 ppm standard, while non-road diesel was capped at 360 ppm. The 360 ppm assumption was negated by the fact that the cases were compared with a reference case that also assumed 360 ppm non-road diesel. Sensitivities of reaching 360 ppm for non-road diesel were performed with other assumptions varied. Cases that assumed 100 percent highway diesel at 10 ppm and non-road and heating oil at 360 ppm resulted in average costs that were between 1.6 cents per gallon and 2.1 cents per gallon higher than in the cases assuming non-road diesel and heating oil at current sulfur levels.

The EnSys analysis also included marginal cost estimates for producing 10 ppm diesel with base technology and no revamp (all new units). The marginal cost of production was 6.6 cents per gallon for the first 25 percent of production, 7.2 cents per gallon for the first 50 percent, 7.7 cents per gallon for the first 75 percent, 9.2 cents pe gallon for the full phase-in, and 10.7 cents per gallon foı an all-at-once approach. The highway diesel volumes produced did not reflect additional production for downgraded product.

ANL Analysis

ANL provided an analysis of total incremental refining and distribution costs for seven different phase-in scenarios to the U.S. Department of Energy (DOE) in August 2000 and updated the estimates in November 2000 based on EPA comments.[140] The most recent ANL estimates were based on average incremental production cost estimates from the EnSys 10 ppm production scenarios and distribution cost estimates for 15 ppm diesel extrapolated from TMC estimates for 5 ppm and 50 ppm diesel.

The ANL analysis used average per-gallon production cost estimates taken as the weighted average of the incremental cost for each quartile of highway diesel production, provided by EnSys. The scenarios had three parameters: the type of technology, the mix of new units versus modified units, and the percent of diesel production required to be 10 ppm. EnSys estimated costs for production under two different investment scenarios: all revamped equipment and all new units. For each investment scenario, EnSys provided cost estimates for both a base technology and an optimistic technology assumption.

The ANL analysis also provided cost estimates for 60 percent revamp/40 percent no revamp given both base and optimistic technology assumptions, by blending the EnSys "all revamp" and "all new" scenarios.[141] The average estimated cost (undiscounted) of producing the first 25 percent ranged from 4.2 to 6.0 cents per gallon; the first 50 percent, 4.0 to 6.0 cents per gallon; the first 75 percent, 4.2 to 6.6 cents per gallon; for 100 percent after phase-in, 4.7 to 7.5 cents per gallon; and for 100 percent all-at-once, 6.0 to 8.1 cents per gallon.[142] Marginal costs were provided by an additional scenario resulting in a marginal cost of 6.6 cents per gallon for the first 25 percent of production, 9.2 cents per gallon for a full phase-in, and 10.7 cents per gallon if the production is required all at once. ANL developed phase-in cost series for the seven scenarios by interpolating between the cost estimates for the different levels of production mentioned above.

[139] EnSys Energy & Systems, Inc, *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000).

[140] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000).

[141] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), Appendix A.

[142] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), Table 1.

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Each of the phase-in cost series provided by ANL was associated with a set of distribution costs, which varied slightly in the seven scenarios. The distribution cost analysis for 15 ppm highway diesel fuel was extrapolated from TMC (early) estimates for distributing 5 ppm and 50 ppm diesel.[143] The costs included capital investment for the distribution and refueling system and for product downgrade. Distribution costs were provided for various levels of phase-in between 5 and 100 percent of the highway diesel market. The level of phase-in most consistent with the 80 percent required by the ULSD Rule for the initial years of the program was a supply of 83 percent of highway diesel, which was associated with undiscounted distribution costs between 1.5 and 2.2 cents per gallon. The costs associated with 100 percent of highway diesel at 15 ppm ranged between 1.2 and 2.1 cents per gallon.[144]

The ANL analysis concluded that, depending on the case and the stage of phase-in, the total incremental costs of a phase-in would range from 6.1 to 11.2 cents per gallon, compared to a range of 7.1 to 12.7 cents per gallon for an all-at-once strategy. Estimates of total (undiscounted) costs to consumers for the various phase-in scenarios ranged from $15.2 to $25.4 billion ($10.1 to $17.3 billion net present value). Higher expenditures were estimated for an all-at-once strategy, with expected costs totaling $30.4 to $52.8 billion ($22.3 to $38.6 billion net present value). The relatively lower distribution costs under a phase-in approach were translated into an estimated savings of $14.2 to $27.4 billion.

Summary of Investment Estimates

EPA estimated that, in order to meet the requirements of the ULSD Rule, the industry would invest a total of $5.3 billion. In comparison, DOE (by ANL) estimated between $8.1 and $13.2 billion of investment for ULSD, Mathpro estimated a range of $3.0 to $6.0 billion, CRA estimated $7.7 billion, and NPC estimated $4.1 billion to meet a 30 ppm standard and substantially higher but undefined amount to provide 15 ppm diesel (Tables 23 and 24). Because production of diesel in the appropriate sulfur range has been very limited, analysis of costs of the ULSD Rule depend heavily on vendor estimates and several critical assumptions, including refinery configuration, size, and crude oil inputs; the ratio of retrofitted units to new units; and the relative cost of retrofits versus new units.

The studies discussed above used different methodologies, economic approaches, levels of regional and annual detail, and assumptions (see Table 20). Many were completed before the Final Rule was issued and do not reflect the provisions for small refineries or the 80/20 rule. In addition, the studies were based on different assumptions about investment behavior and costs and the level of diesel demand. The capital investment estimates are difficult to compare not only because of their different methodologies and assumptions but also because their investment estimates reflect slightly different things. For instance, the EPA estimated the capital cost for a new distillate hydrotreater to range

Table 23. Comparison of ULSD Production Cost Estimates: Individual Refinery Representation

Study	Sulfur Level (ppm)	Percentage of Highway Diesel That is ULSD	Cost Change (1999 Cents per Gallon of ULSD)	Cost Basis	Refinery Capital Investment (Billion 1999 Dollars)
EPA - Temporary compliance, 2006-2010	7	75[a]	4.[illegible][b]	Average, U.S.	[illegible]
EPA - Full compliance, June 2010 forward	7	100	4.3	Average, U.S.	5.3 total
CRA/BOB (August 2000 for 2006)	7[c]	100	6.7[d]	Average, U.S.[e]	--
EIA - cost curves, 2006	7	76-100	5.4-6.8	Marginal, PADDs [illegible]	

[a] Small refiners accounting for 5 percent of production are eligible to delay, but only 2 percent are assumed to delay.
[b] Cost adjusted for credit trading at cost to low cost refiners.
[c] Correspondence with Ray Ory of Baker and O'Brien. Also reflects assumption of 350 ppm non-road diesel.
[d] Average cost to produce 7 ppm diesel from 500 ppm diesel. The marginal price to balance supply and demand was estimated to be between [illegible] and [illegible] cents per gallon, depending on the availability of imports.
[e] Average based on marginal cost methodology.
[f] Marginal based on average refinery costs.
Sources: EPA: U.S. Environmental Protection Agency, *Regulatory Impact Analysis, Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/[illegible]. CRA/BOB: Charles River Associates, Inc., and Baker and O'Brien, Inc., *An Assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000). EIA: Energy Information Administration, Office of Integrated Analysis and Forecasting (Chapter 5 of this report).

[143] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000).
[144] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), Appendix C.

from $1,240 per barrel per day to $1,680 per barrel per day, whereas those in EIA's refinery-by-refinery analysis ranged from $1,043 to $1,807, and in EIA's NEMS Regulation case they were $1,331 to $1,849 per barrel per day (Table 25).

The sets of capital costs used in the EIA and EPA analyses are not directly comparable. The lower-bound of EPA's capital costs represents a 25,000 barrel per day hydrotreater processing 100 percent straight-run feedstock, and the upper-bound reflects the same unit processing 100 percent light cycle oil. The EPA's upper and lower bound costs encompass a third estimate for a unit processing entirely coker distillate. The capital costs for individual refineries in the EPA analysis vary acros this range, depending on the assumptions about proportions of straight-run distillate, coker distillate, and light cycle oil processed at each refinery and the size of the hydrotreater unit. The capital cost range for EIA's refinery-by-refinery analysis also varies for the quality of the feedstock and size of each unit. EIA's short-term analysis reflects actual data about the quality of crude oil and feed streams at individual refineries. In contrast, EIA's mid-term NEMS analysis does not use refinery-specific information about feed steams but aggragates feed and crude quality information at a regional level.

Table 24. Comparison of ULSD Production Cost Estimates: LP Model or Based on LP Results

Study	Sulfur Level (ppm)	Percent of Highway Diesel That is ULSD	Cost Change (1999 Cents per Gallon of ULSD)	Cost Basis	Refinery Capital Investment (Billion 1999 Dollars)
Mathpro (August 2000)	8	100	4.5-7.1[a]	Average U.S.	3.0-6.0[a]
NPC (June 2000)	30	100	5.9	Average PADDs I-III	4.1
EnSys (August 2000), first 50 percent of production at 10 ppm	10[b]	50	4.4-6.0[c]	Average PADD III	
EnSys (August 2000), next 25 percent of production at 10 ppm	10[b]	75	6.0-7.9[c]	Average incremental cost of next 25% PADD III	
EnSys (August 2000), final 25 percent of production at 10 ppm	10[b]	100	7.6-10.1[c]	Average incremental cost of final 25% PADD III	
EnSys (August 2000); 25% to 100%	10[b]	25-100	6.6-10.7[d]	Marginal PADD III	
ANL (November 2000), up to 50% of production at 10 ppm	10	50	4.0-6.0[d]	Average PADD III	
ANL (November 2000), 75% of production at 10 ppm	10	75	4.2-6.6[c]	Average PADD III	
ANL (November 2000), 100% of production at 10 ppm	10	100	4.7-7.5[c]	Average PADD III	8.1-13.2 (August 2000 estimate)[e]
ANL (November 2000), 100% of production at 10 ppm, all-at-once	10	100	6.0-8.1[c]	Average PADD III	
ANL (November 2000), 25% to 100%	10	25-100	6.6-9.2[d]	Marginal PADD III	
EIA (NEMS, 2007-2010)	7	76[f]	4.7-7.3[g]	Marginal, U.S. average	4.2-5.9 through 2007
EIA (NEMS, 2011)	7	100	6.5-9.2[g]	Marginal, U.S. average	6.3-9.3 through 2011

[a]Non-road 3500 ppm.
[b]Reflects assumption of 360 ppm non-road diesel but the cost impact is negated because it is compared with a reference case with non-road diesel at the same sulfur level.
[c]The higher end of the cost range reflects base technology while the lower end reflects more optimistic technology.
[d]Marginal costs at 25 percent and 100 percent 10 ppm production with base technology and all new units.
[e]U.S. Department of Energy, "Comments of the Department of Energy on the Environmental Protection Agency's May 16, 2000 Notice of Proposed Rulemaking on Heavy-Duty Engine and Vehicle Emission Standards and Highway Diesel Fuel Sulfur Control" (Washington, DC, September 2000), Enclosure 1.
[f]Small refiners accounting for 5 percent of production are eligible for the small refinery provision, but only 4 percent of production is assumed to be delayed.
[g]Average refinery gate price for individual years.

Sources: **Mathpro**: Mathpro, Inc., *Refining Economics of Diesel Fuel Sulfur Standards: Supplemental Analysis of 15ppm Sulfur Cap* (Bethesda, MD: August 2000). **NPC**: National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000). **EnSys**: EnSys Energy & Systems, Inc, *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000). **ANL**: M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000). **EIA**: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, DSU7IMP0.D043001A, DSUREF10.D043001A, and DSU7PPM10.D043001A.

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The lower end cost in EIA's NEMS analysis reflects a notional unit that processes low-sulfur feed with incidental dearomatization, while the higher end cost reflects a different notional unit that processes higher sulfur feed with greater aromatics improvement. EIA also provided sensitivity analysis using higher capital cost assumptions for both the refinery-by-refinery and NEMS analyses. The Higher Capital Cost sensitivity case for EIA's refinery-by-refinery analysis is based on capital costs that are about 40 percent higher than those in the initial analysis. Both sets of capital costs were developed by the National Energy Technology Laboratory, in conjunction with Mr. John Hackworth, energy consultant. The capital costs used in the NEMS Higher Capital Cost case were provided by recent work from EnSys and are 24 percent higher for the first notional unit and 33 percent higher for the second notional unit, relative to the Regulation case.

The EPA analysis was based on estimates from two technology vendors, providing costs based on retrofits and new units.[145] EPA assumed that 80 percent of ULSD will be produced from diesel hydrotreaters that are revamped at a cost of $40 million each. These estimates reflected an assumption that new units would cost twice as much as revamps. The net result was an estimated average cost of $50 million per refinery, which equates to a little more than 4 cents per gallon of highway diesel on average.

The NPC analysis did not estimate costs for producing diesel with less than 10 ppm sulfur but indicated that even a 30 ppm sulfur standard would require reactor pressures in the range of 1,100 to 1,200 psi, which is well above the vendor estimates used by the EPA.[146] The NPC characterized vendor estimates as inherently over-optimistic;[147] however, several new technologies are under development that may reduce costs (see Chapter 3).

The ANL estimates blended the EnSys 100 percent new and 100 percent revamp refinery analysis, based on the assumption that 60 percent of ULSD would be produced from revamped units that cost an average of $40 million per unit, and the other 40 percent would come from new units at an average cost of $80 million per unit. Instead of making an assumption about the split between revamped and new units, Mathpro developed scenarios for different types of choices. Assuming no change in the non-road diesel standards, Mathpro estimated that the total investment cost would range from $6.0 billion if refineries required all new units with minimum operating flexibility to $3.0 billion if all refineries were retrofitted and economies of scale from trading were realized.

Table 25. Comparison of Key Hydrotreator Investment Assumptions for Various Refinery Models

Model	Capital Cost of New Hydrotreater (1999 Dollars per Barrel per Day, ISBL)	Revamp Cost as a Percentage of New Unit Cost	Unit Size (Barrels per Day)	Percent of ULSD Production from Revamped Units Versus New Units
Refinery-by-Refinery Models				
CRA/BOB	1,622[a]	65	25,000	60/40
EPA	1,240-1,680[b]	50	25,000	80/20
EIA Cost Curve	1,043-1,807[c]	Variable	50,000-10,000	Not an assumption
EIA Cost Curve High Capital Cost Scenario	1,466-2,548c	Variable	50,000-10,000	Not an assumption
LP Models				
EnSys August 2000	2,350-3,296[d]	60	25,000	N/A
EIA NEMS Regulation Case	1,331-1,849[d]	50	25,000-10,000	80/20
EIA NEMS 2/3 Revamp Case	1,331-1,849[d]	50	25,000-10,000	66.7/33.3
EIA NEMS Higher Capital Cost Case	1,655-2,493[d]	50	25,000-10,000	80/20

[a]Feedstock composed of 65 percent straight-run distillate, 10 percent cracked stock, and 25 percent light cycle oil.
[b]Low end of range is for straight-run distillate and high end is for light cycle oil.
[c]Costs varied depending on unit size and feedstock.
[d]Low end of range is for units processing low-sulfur feed streams with incidental dearomatization. High end is for higher sulfur feed streams with greater aromatics improvement.
Sources: **CRA/BOB**: Correspondence with Mr. Ray Ory, April 19, 2001. **EPA**: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, Table V.C-9, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. **EIA Cost Curve and Cost Curve High Capital Cost Scenario**: National Energy Technology Laboratory, in conjunction with Mr. John Hackworth, energy consultant. **EnSys**: EnSys Energy & Systems, Inc., *Modeling Impacts of Reformulated Diesel Fuel* (Flemington, NJ, August 2000). **EIA/NEMS Regulation and 2/3 Revamp Cases**: Office of Integrated Analysis and Forecasting. **EIA/NEMS High Capital Cost Case**: Revised EnSys costs based on correspondence with Mr. Martin Tallett, April [illegible] 2001.

[145]EPA corroborated the vendors' cost estimates in discussions with two other vendors. E-mail from Lester Wyborny, U.S. Environmental Protection Agency, March 30, 2001.

[146]M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), p. 132.

[147]National Petroleum Council, *U.S. Petroleum Refining: Assuring the Adequacy and Affordability of Cleaner Fuels* (June 2000), p. 77.

The EIA NEMS analysis produced estimates for the refinery capital investment required to comply with the ULSD Rule for 2007 and 2010. The cumulative refinery capital investment estimated through 2007 ranged between $4.2 billion and $5.9 billion. The NEMS analysis produced an estimate of refinery capital investment between $6.3 billion and $9.3 billion through 2011.

Distribution Cost Analyses

EPA, ANL, and TMC have published estimates of distribution costs given different assumptions about the phase-in requirements for highway diesel. In general, the cost estimates for distributing a smaller percentage of 15 ppm fuel were higher than estimates assuming that 100 percent of the highway diesel market would be at 15 ppm, because a phase-in approach requires the distribution system to handle an extra product (Table 26).

Distribution cost estimates from the EPA, ANL, and TMC analyses included the capital incurred in the distribution and refueling system, as well as costs resulting from downgraded product. The EPA estimated that distribution costs would increase by 1.1 cents per gallon during the temporary compliance period, with 0.4 cents of the cost associated with the distribution and energy loss of the ULSD relative to 500 ppm diesel and 0.7 cents associated with capital expenses for handling two grades of highway diesel. EPA assumed that the capital costs would be fully amortized during the transition period (by 2010), and that revenue losses from product downgrade and other operating costs would increase distribution costs by 0.5 cents per gallon.

EIA's NEMS analysis assumed the EPA's estimated capital costs of 0.7 cents per gallon and portions of EPA's other distribution costs, including operating, transmix, and testing costs, which totaled 0.2 cents per gallon. EIA estimated the cost associated with the revenue loss of the downgraded product at 0.3 cents per gallon through 2010 and 0.2 cents per gallon after 2010 (see Chapter 6). The EIA revenue loss estimates were based on model results. A higher revenue loss estimate of 0.7 cents per gallon for all years was associated with EIA's 10% Downgrade sensitivity case, because more of the ULSD

Table 26. Comparison of ULSD Distribution Cost Estimates and Assumptions

Study	Sulfur Level (ppm)	Year	Distribution Cost Change (1999 Cents per Gallon)	Investment (Billion 1999 Dollars)	Downgrade Estimates
TMC	5		7 at 5% 4.1 at 20% 1.5 at 100%	0.215 1.05 1.08	10.0% 12.0% 19.5%
TMC	15		6.9 at 5% 4.1 at 20% 1.4 at 100%	0.215 1.05 1.08	9.5% 11.0% 17.5%
TMC	50		Costs 15% to 35% less than 5 ppm costs		8.0% 10.0% 13.5%
ANL	15		6.2 at 5% 1.6-2.2 at 74%-100% 1.2-2.1 all-at-once Costs are undiscounted and include refueling costs	50% of terminals reconfigure split between new tankage at $1 million per terminal and modified tankage at $100,000 per terminal	Same as TMC 5 ppm and 50 ppm
EPA (temporary compliance)	15	2006-2010	1.1	0.5	4.4%
EPA (full compliance)	15	Post-2010	0.5	0.3	4.4%
CRA/BOB	15				10.0% above current
EIA Regulation Case (temporary compliance)	15	2007-2010	1.2		4.4%
EIA Regulation Case (100% ULSD)	15	Post- 2010	0.4		4.4%
EIA 10% Downgrade Case (temporary compliance)	15	2007-2010	1.6		10%
EIA 10% Downgrade Case (100% ULSD)	15	Post- 2010	0.9		10%

Sources: Sources: **EPA**: U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, web site www.epa.gov/otaq/regs/hd2007/frm/ria-v.pdf. **CRA/BOB**: Charles River Associates, Inc., and Baker and O'Brien, Inc., *An assessment of the Potential Impacts of Proposed Environmental Regulations on U.S. Refinery Supply of Diesel Fuel*, CRA No. D02316-00 (August 2000). **ANL**: M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000). **TMC**: Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000). **EIA**: National Energy Modeling System, runs DSUREF.D043001B, DSU7PPM.D043001A, DSU7HC.D043001A, DSU7INV.D043001A, DSU7DG10.D043001A, DSU7TRN.D043001A, DSU7BTU.D043001A, DSU7ALL.D050101A, DSU7IMP0.D043001A, DSUREF10.D043001A, and DSU7PPM10.D043001A.

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produced was projected to be downgraded to a lower value product.

The ANL estimates, which were extrapolated from previous TMC estimates for delivering 5 ppm and 50 ppm diesel,[148] ranged from 6.2 cents to 1.2 cents per gallon for delivery of 5 percent and 100 percent, respectively.[149] In August 2000, TMC provided supplemental estimates reflecting downgrade costs associated with distributing 15 ppm diesel fuel.[150] Presumably, the capital costs would remain the same as for the 5 ppm case in the previous TMC analysis. When the original TMC 5 ppm estimates are adjusted to reflect 15 ppm diesel, the total distribution cost estimates are 6.9 cents per gallon to supply 5 percent of the market; 4.1 cents per gallon to supply 20 percent of the market; and 1.4 cents per gallon to supply the entire highway diesel market.[151]

The extent to which product contamination will occur in the distribution system (and how much product must be downgraded as a result) is very uncertain. The analyses included strikingly different estimates of how much of the 15 ppm product would be downgraded in the distribution system. EIA's NEMS analysis assumed 4.4 percent downgrade for consistency with the EPA assumptions but also provided a sensitivity case assuming 10 percent downgrade. Downgrade estimates ranged from 4.4 percent of production (EPA) to 17.5 percent (TMC). Part of the uncertainty stems from not knowing the present level of downgrade occurring in the distribution system, because there is no current reporting requirement. The EPA assumed a doubling of product downgrade from current downgrade levels, which were estimated at 2.2 percent. The methodology used by the EPA to estimate current downgrade levels was highly speculative and was not based on a scientific survey. The EPA's estimation methodology was loosely based on a survey of the Association of Oil Pipelines, in which six respondents provided estimates of the current diesel fuel downgrade ranging from 0.2 percent to 10.2 percent (see Chapter 4). In the same survey some respondents expressed an expectation that the downgrade amount might be expected to double under the ULSD Rule.

The TMC analysis was based on a survey of 14 refiners (representing 38 percent of U.S. petroleum refining capacity), 3 pipeline operators (representing approximately 40 percent of U.S. highway diesel shipping capacity), and 11 terminal operators (representing 25 percent of U.S. petroleum product storage capacity). A wide range of responses was noted in the responses of pipeline operators. In the survey, some terminal operators indicated that they would not handle ULSD. Terminal operators generally anticipated a higher rate of downgrade than did pipeline operators. Terminal operators indicated that, to handle ULSD, dedicated transport trucks or compartments in transport trucks would be required to avoid sulfur contamination.[152]

The TMC analysis projected 17.5 percent downgrade when 100 percent of the highway diesel market was assumed to require the 15 ppm diesel, and slightly lower levels of downgrade were expected when smaller segments of the market were required. Although the ANL analysis did not provide the downgrade assumptions used, it was based on the TMC assumptions for downgrade of 5 ppm and 50 ppm diesel and tracked closely with the TMC assumptions. Different downgrade assumptions resulted in different cost estimates associated with downgrade. The EPA estimated a total downgrade cost of 0.2 cents per gallon for all highway diesel in the initial years and 0.3 cents per gallon after full implementation.[153] In contrast, the ANL analysis (based on the TMC assumptions of higher downgrade volumes) estimated a total downgrade cost of about 1 cent per gallon when more than half of the market was required to meet the 15 ppm standard.

The TMC, EPA, and ANL analyses also used different sets of assumptions about capital investment requirements. During the initial years of the program, when the distribution system must handle two highway diesel fuels, the EPA estimated tankage costs at refineries, terminals, pipelines, and bulk plants at $0.81 billion. In addition, investments at truck stops to handle the extra product were estimated at $0.24 billion. These costs were amortized over total highway diesel volumes (both 500 ppm and 15 ppm) during the initial 4 years at 7 percent per year, resulting in a cost of 0.7 cents per gallon. EIA used EPA's capital cost estimate of 0.7 cents per gallon in all NEMS analysis scenarios.

The ANL analysis assumed that, given a phase-in, 50 percent of terminals would add tanks or reconfigure. Of those terminals that were modified, it was assumed that

[148] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000)

[149] M.K. Singh, *Analysis of the Cost of a Phase-in of 15 ppm Sulfur Cap on Diesel Fuel*, Revised (Argonne, IL: Center for Transportation Research, Argonne National Laboratory, November 2000), Appendix C.

[150] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000), *Revised Supplement* (August 2000).

[151] Total distribution and retail cost estimates for 5 ppm from *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* were adjusted based on update of downgrade costs for 15 ppm diesel provided in the *Revised Supplement*

[152] Telephone conversation with Bob Cunningham of Turner Mason, March 21, 2001

[153] U.S. Environmental Protection Agency, *Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Requirements*, EPA420-R-00-026 (Washington, DC, December 2000), Chapter V, p. V-124.

half would add tankage at $1 million per terminal and the other half would reconfigure at a cost of $100,000 per terminal. Bulk terminals were not assumed to make conversions for a second highway diesel fuel, because they were assumed to enter into exchange agreements with marketers during a phase-in period, rather than investing in tankage. In addition, all truck stops were assumed to be modified to provide two fuels during the phase-in, at a cost of $75,000 per truck stop.

The original TMC report provided investment estimates for distributing 5 ppm fuel to supply, 5, 20, and 100 percent of the highway diesel market. Investments at terminals and pipelines were estimated at $295 million when supplying 20 percent of the highway market and $325 million for 100 percent of the market. Retail investments were estimated at $755 million for both 20 percent and 100 percent of supply. Unlike the other two analyses, which reflected the cost of conversion to truck stops only, TMC assumed that some gasoline stations would invest to carry a second diesel fuel.[154]

Downgrade Analysis

The MSC study, *Alternative Markets for Highway Diesel Fuel Components*, conducted at the request of the EPA, provided an analysis of the potential for diverting sub-specification highway diesel to non-road or foreign markets.[155] The study compared 2007 projections for supply and demand of distillate products to assess the outlook for non-road distillate market growth and used relative relationships of highway diesel to non-road distillate prices to estimate the economic consequences of diverting to other products.

The analysis used historical industry-level distillate demands for each PADD from EIA's *Fuel Oil and Kerosene Sales* as a starting point.[156] These industry level demands were projected out to 2007, using national annual growth rates from the *Annual Energy Outlook 2000*.[157] PADD-level supply balances for distillate fuel were projected for 2007, starting with historical data from the *Petroleum Supply Annual 1999*[158] and applying growth rates from the *Annual Energy Outlook 2000*. Import and export levels were held constant in PADDs II and IV. In PADD V, inter-PADD transfers were held to historical levels and imports and exports were used as a balancing item. The study concluded that there was little potential to divert highway diesel to non-road distillate markets, and that the potential for severe market dislocations and/or price depression in the non-road markets was greatest in PADD IV and least in PADD I.

The price consequences of diverting product from the highway diesel market to non-road markets were assessed using estimated price relationships for these products derived from historical price data from various industry pricing agencies (e.g., Platts), combined with relevant transportation costs.[159] The price implications of downgrading 5 percent, 10 percent, and 15 percent of the current highway diesel supply were estimated for each PADD (Table 27). The price impact of diverting 5 percent of the highway diesel supply to other uses ranged from -3.0 cents per gallon in PADD I to -6.0 cents per gallon in PADD IV. The range widened to -3.5 to -20.0 cents per gallon in PADDs I and IV, respectively, for 10 percent of diverted product and to -3.5 to -22.0 cents per gallon for 15 percent of diverted product. The study concluded that except in PADD IV, a 5-percent diversion of product would have modest market impact. In addition, a 10- to 15-percent diversion would have a significant market impact in all areas except PADD I.

Table 27. Projected Relative Price Decrease by PADD and Percentage of Diverted Diesel
(1999 Cents per Gallon)

Diversion Level (Percent)	PADD I	PADD II	PADD III	PADD IV	PADD V
5	3.0	2.5	4.0	6.0	5.0
10	3.5	14.0	4.5	20.0	5.0
15	3.5	16.0	4.5	22.0	6.0

Source: Muse, Stancil & Co., *Alternative Markets for Highway Diesel Fuel Components* (September 2000), p. 4.

[154] Turner, Mason & Company, *Costs/Impacts of Distributing Potential Ultra Low Sulfur Diesel* (Dallas, TX, February 2000), p. 6.
[155] Muse, Stancil & Co., *Alternative Markets for Highway Diesel Fuel Components* (September 2000).
[156] Energy Information Administration, *Fuel Oil and Kerosene Sales*, DOE/EIA-0535 (Washington, DC, 1995-1998).
[157] Energy Information Administration, *Annual Energy Outlook 2000*, DOE/EIA-0383(2000) (Washinton, DC, December 1999).
[158] Energy Information Administration, *Petroleum Supply Annual 1999*, Volume 1, DOE/EIA-0340(99/1) (Washington, DC, June 2000).
[159] Muse, Stancil & Co., *Alternative Markets for Highway Diesel Fuel Components* (September 2000), pp. 19-32.

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Appendix A

Letters from the Committee on Science, U.S. House of Representatives

U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON SCIENCE

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July 26, 2000

Mr Lawrence A. Pettis
Acting Administrator
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

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 is 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 middle distillate 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 engine 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 change if the effective date was later (i.e., refinery changes for diesel did not have to overlap those for gasoline sulfur)?

Mr. Lawrence A. Pettis
July 26, 2000
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- What are the effects of EPA's proposal on the diesel fuel distribution system? In particular, to what extent might fuel contamination occur when shipping low sulfur diesel in common pipelines with other, higher sulfur products? What is the capability of current testing methods to accurately measure sulfur level in the context of a 15 PPM sulfur cap? What operational changes, such as batch size and product sequence changes, would be necessary and how would they contribute to likely consumer costs?

- Although not proposed in the rule, EPA has asked for comments related to the feasibility of phasing-in low sulfur highway diesel over the course of several years. Such a phase-in would require the introduction of a second grade of highway diesel fuel into the supply and distributions systems. What would be the impacts on the distribution system of a phase-in of low sulfur highway diesel? What additional investments would be needed to ensure the integrity of both the low sulfur and high sulfur product at the retail level? Would a separate infrastructure be required to adequately deliver product to market? How would these investments be recouped by the industry?

- What effect would EPA's proposed standard have on refinery operations? Would additional processing be required and would that affect refinery product yield and fuel consumption within the refinery?

- Do adequate, cost-effective technologies exist to allow refineries to adjust to the new 15 PPM standard? Are technologies in development that could reduce the costs in the future, and is there a high likelihood of their deployment into the market in a timely manner?

We are requesting that the EPA keep the proposed rule on the 15 PPM diesel sulfur cap public comment period open pending receipt of your findings. Thank you for your attention to this matter.

Sincerely,

F. JAMES SENSENBRENNER, JR.
Chairman

RALPH M. HALL
Ranking Minority Member

KEN CALVERT
Chairman
Subcommittee on Energy and Environment

JERRY F. COSTELLO
Ranking Minority Member
Subcommittee on Energy and Environment

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U.S. HOUSE OF REPRESENTATIVES

COMMITTEE ON SCIENCE

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January 24, 2001

Mr. Lawrence A. Pettis
Energy Information Administration
U.S. Department of Energy
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Pettis:

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 Btu 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) 225-4778 if you have any questions.

Sincerely,

Harlan Watson

Harlan Watson
Staff Director
Energy & Environment Subcommittee

HW:tjv

Enclosure

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Appendix B

Differences From the *AEO2001* Reference Case

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*).[160] Both the reference case for this study and the *AEO2001* reference case were prepared using EIA's National Energy Modeling System (NEMS).[161] 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.

[160] Energy Information Administration, *Annual Energy Outlook 2001*, DOE/EIA-0383(2001) (Washington, DC, December 2000), web site www.eia.doe.gov/oiaf/aeo/. See also web sites www.eia.doe.gov/oiaf/assumption/pdf/0554(2001).pdf and www.eia.doe.gov/oiaf/supplement/index.html.

[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.doe.gov/bookshelf/docs.html.

Appendix C

Pipeline Regions and Operations

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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 fuel oils. 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 Product 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, TEPPCO (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

PADD III and receives supplies from El Paso, TX. The Calnev Pipeline connects southern California with Las Vegas, NV. There are also pipelines transporting product in western Washington and Oregon from refineries in the northwest corner of Washington (Kinder Morgan and Olympic). As noted previously, Chevron supplies the eastern part of those States via pipeline from Salt Lake City, and Yellowstone delivers across Montana and Idaho into eastern Washington as well.

The East Coast is the only region where all pipelines consistently carry both diesel fuel (currently 500 ppm) and high-sulfur distillate fuel oil (heating oil). In other regions, some demand for non-road fuel is met by 500 ppm product. This is important to the demands of a phase-in.

Key Pipeline Operations

Oil pipelines operate under a range of corporate structures and face a range of operational and financial challenges. Some are independent and face capital markets on their own. Others are subsidiaries of integrated oil companies. Oil pipelines also serve their markets in different ways, and their divergent operations patterns dictate that the impact of the rule will vary across pipelines and thus across regions. The options for minimizing contamination may be different for a trunk line than for a delivering pipeline carrier, or for a pipeline in batch service versus one in fungible service. In addition, the opportunities for offsetting a supply interruption caused by a quality problem are fewer for the delivering carrier in batch service. The sequencing of product flow is central to maintaining product integrity and, possibly, reducing system flexibility by requiring changes in batch sizes or product scheduling.

Trunk Line and Delivering Pipeline Carriers

Refined petroleum products pipelines in the United States fall into two fundamental service categories. Trunk lines serve high-volume, long-haul transportation requirements; delivering pipelines transport smaller volumes over shorter distances to final market areas. Trunk pipelines provide transportation between major source points, such as the Gulf Coast, and major consumption locations, such as the East Coast. An example of a trunk pipeline is Colonial Pipeline Company, which operates from Houston to New York City. Delivering pipelines provide transportation from source points to multiple, but relatively nearby, market areas. An example of a delivering pipeline is Buckeye Pipe Line Company, which operates in the middle Atlantic and upper Midwest regions of the country from various source points, such as New York and Chicago, to markets such as Pittsburgh and Detroit. While the average haul length on Colonial Pipeline is over 1,000 miles, the average haul length on Buckeye is 125 miles.

Both trunk line and delivering pipeline carriers are necessary for meeting the Nation's demand for refined petroleum products, and each type of pipeline carrier is economically sound in performing its type of service. Many pipeline companies provide both types of service. It is clear, however, that trunk and delivering pipeline carriers encounter different operating environments and different economics. Trunk lines tend to have lower costs and revenues per barrel mile than delivering carriers. Trunk line carriers also tend to be more capital intensive than delivering carriers. Costs and revenues per unit of throughput are higher for delivering carriers than for trunk lines, and delivering carriers tend to be more labor intensive than trunk carriers. Delivering carriers also tend to operate physically smaller pipelines and to use more and smaller storage tanks than do trunk carriers.

The fundamental difference between trunk line and delivering pipeline carriers is scale. For pipelines closer to ultimate demand locations, the magnitude of operations tends to be smaller and the number of operating tasks performed tends to be larger. The trunk carriers that serve as the central arteries have flexibility to redirect product, for instance. As the system reaches its furthest capillaries, the inflexibilities imposed by the smaller scale become more apparent. The chances for "operating lockouts" increase. A lockout might occur if 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.

Batch and Fungible Pipeline Service

Petroleum products 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.

A pipeline carrier operates in a batch or fungible mode based on its circumstances. Unless there is a more compelling reason, a pipeline operator's selection of its mode of service is based on maximizing operating and economic efficiency. In general, fungible product operation is the more efficient mode of operation. Fungible operation tends to minimize the generation of interface material (see below). Another efficiency of fungible operation is that it permits split-stream operations. In a split-stream operation, material originating at Point A 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.[162] 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

[162] Based on ton-miles. See Association of Oil Pipe Lines, *Shifts in Petroleum Transportation—1999* (2001).

far in advance, however, leaving little opportunity for last-minute flexibility.

Batch sizes are determined by the availability of storage tankage (not only to pipeline operator directly, but also to originating shippers and receiving terminal operators), the batch sizes consigned by shippers, shippers' time requirements, and whether the pipeline is operated on a batch or fungible basis.

Interfaces and Transmix

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 is typically blended into the lower grade. This "downgrading" reduces the volume of the higher quality product and increases the volume of the lower quality product.

The interface between two different products—gasoline and a distillate, for instance—produces a hybrid called "transmix." Transmix cannot be blended back into either of its components, as gasoline's flash point will contaminate the distillate, and distillate's higher boiling point will contaminate the gasoline. Transmix, therefore, is segregated and then reprocessed in a full-scale refinery or a purpose-built facility. When it has been separated again into its component products (gasoline and distillate, for instance), the distinct products are reintroduced into the appropriate segregated transportation and storage system. (If an operator utilizes two physical pipelines in the same corridor, it may minimize the generation of transmix by carrying only gasoline in one line and only distillates in the other. The problem of downgrade within a family of products, however, still exists.)

As shown in Figure C1, a refined products pipeline typically "wraps" the current highway diesel (at 500 ppm) with kerosene and/or jet fuel (2,000 ppm or so), and non-road diesel (up to 5,000 ppm). The chance that the 500 ppm material will be forced off-specification by sulfur contamination is low. The product tendered is around 300 ppm, leaving leeway for any minor contamination from the neighboring 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 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.

Storage 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. Operators usually are able to place the same type of petroleum fuel in a given tank on each drain and fill cycle, and the tank is not purged and cleaned between the routine drain and fill cycles. When a tank is filled and drained with a given material, small to substantial quantities of the former material remain in the tank. To the extent that the previous material was different from new material being placed in the tank, contamination can occur. Generally, such contamination is inconsequential because the new material is substantially the same as the old material or its volume is small.

In addition to tanks at the origin and destination terminals, "working" or "breakout" tanks are used in the normal course of pipeline operation. Over a pipeline route, there may be various needs to interrupt the flow of pipeline material in transit, including branching of the pipeline, change in size or capacity, mainline pumping operations, change from fungible to batch operation, and others. In each case, breakout tanks provide the flexibility to temporarily stop or buffer different flow rates of pipeline segments.

The maintenance of material in continuous pipeline transit without need for diversion into breakout tankage is known as "tightlining." A pipeline operator's ability to tightline material will prove to be a slight advantage in protecting the integrity of ULSD. Overall, however, tightlining is not an easy option to engage if facilities and operating requirements do not already permit it.

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

Making the Cut: The Mechanics of the Interface

Each petroleum product—in fact, each batch of products—has a distinct and identifiable specific gravity. Different products have widely different specific gravities. Different grades or batches of the same product have slight but measurable differences in specific gravity.

Pipeline operators monitor the specific gravity of a pipeline stream as it approaches a station or terminal. A change from one specific gravity to another indicates the end of the leading batch and the beginning of the following batch. Based on this signal of the interface location, the pipeline operator "swings" batches from one pipeline to another or from mainline transit into segregated tanks. The shift in specific gravity may be too gross an indicator, however, when dealing with ULSD. By the time the shift in specific gravity is discernible, the ULSD may have been contaminated by the sulfur in its neighboring product.

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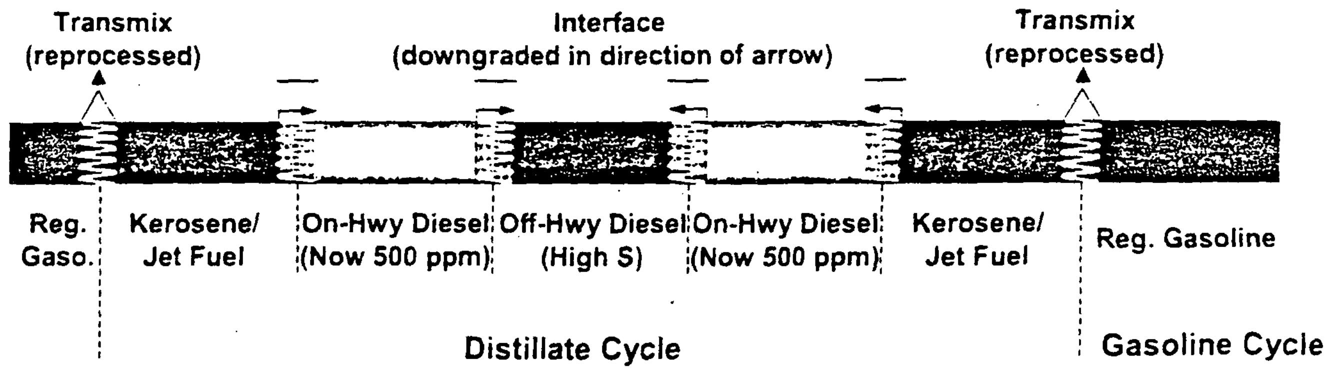
Figure C1. Typical Product Sequence and Interfaces in a Refined Products Pipeline



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

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.