THE STATUS OF THE U.S. REFINING INDUSTRY

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY AND AIR QUALITY

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

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THE STATUS OF THE U.S. REFINING INDUSTRY

THURSDAY, JULY 15, 2004

HOUSE OF REPRESENTATIVES,
COMMITTEE ON ENERGY AND COMMERCE,
SUBCOMMITTEE ON ENERGY AND AIR QUALITY,
Washington, DC.

The subcommittee met, pursuant to notice, at 10 a.m., in room 2123, Rayburn House Office Building, Hon. Ralph M. Hall (chairman) presiding.

Members present: Representatives Hall, Whitfield, Shimkus, Fossella, Bono, Rogers, Issa, Otter, Sullivan, Barton (ex officio), Allen, Waxman, Wynn, Capps, Doyle, and Dingell (ex officio).

Also present: Representative Tauzin.

Staff present: Bill Cooper, majority counsel; Mark Menezes, majority counsel; Sue Sheridan, minority counsel; Bruce Harris, minority counsel; Michael Goo, minority counsel; and Dick Frandsen, minority counsel.

Mr. HALL. The subcommittee will come to order. Without objection, the subcommittee will proceed pursuant to Committee Rule 4(e). So ordered. The Chair recognizes himself for an opening statement.

Oil prices on the futures market closed yesterday at 41 bucks a barrel. The headlines in many of the media outlets say that the reason is based on concerns about crude oil and fuel supplies. U.S. refiners pulled some 200,000 barrels of gasoline from storage last week, due to higher outputs, raising performance to 95.2 percent of capacity. Bloomberg reports, "Last week's 2.1 million barrel draw on U.S. commercial oil stockpiles was quadrupled to 500,000 barrels median estimate of ten analysts surveyed by Bloomberg." In other words, demand is so strong that even the professionals were fooled.

The Energy Information Administration, in its weekly petroleum reports, says that it expects demand to grow 1.5 to 2 percent per year, on average, and whether existing domestic refinery expansions keep pace with demand, we just don't know. Most analysts say that they will not.

Today's edition of Oil Daily reports that the past 3 years have used an additional 180,000 barrels per day of gasoline output, "well below the increase in gasoline demand." How do we make up the difference if we don't expand capacity domestically? We increase imports. Again, Oil Daily reports "to satisfy demand, imports of finished motor gasoline have increased by nearly 100,000 barrels per

day to 555,000 barrels per day in May." Now, these are staggering numbers and this is sobering news.

Every week, the trade magazines and newspapers report the number of refineries closed for maintenance, unanticipated breakdowns, or other problems. It reads like a rural newspaper reporting on the weekly gossip in the community, but the news is far more serious. Why? Because refineries are stretched to the limit, and any shutdown, no matter how minor, has a major impact on the market. Any shutdown is big news.

So, today we will hear from just about every stakeholder in the refining world the main focus on refining capacity, and all that subject might encompass. Hopefully, based upon the testimony presented, Congress can decide its rightful role in assuring an affordable adequate supply of gasoline for the consuming public for years to come.

I can't envision a more important hearing than this hearing today, and I am very grateful, on behalf of the subcommittee, to you men and women who have given your time and are giving your knowledge. You will help us write the legislation, and we know it took you time to get here, time to prepare to come here, time to give your testimony, and we are very grateful to you.

So, I again thank all the witnesses for your testimony and your willingness to take time out of your schedules to be here, and I now recognize Mr. Gene Green for an opening statement.

Mr. GREEN. Thank you, Mr. Chairman. And like you, I am glad this hearing has been called today because it is important. Gas price fluctuation has hit all American consumers hard, especially those on tight family budgets. But most folks don't have a clear picture of all the steps that it takes to get gasoline into the family car at a given price.

High prices at the pump are basically due to the high price of the crude oil and refining capacity shortages. The high price of crude is a result of instability in the Middle East, which does not appear to be improving, and Congress' inability to allow reasonable environmentally responsible oil and gas production in the U.S. either in Alaska or off-shore. For one, I believe that producing oil and gas safely in Alaska and off-shore is much easier and less costly than attempting to bring democracy to the Middle East. Refining capacity is short because of the investment climate that limits investments and capacity expansion. That is the proper focus of today's hearing.

I am in a unique position where blue collar workers at the refineries in my district provide a tremendous amount of gasoline for the nation. The Houston area is by far the largest concentration of refining capacity, with the Gulf Coast accounting for approximately 40 percent of our Nation's gasoline supply. The number of refineries in the United States has fallen dramatically from over 200 in 1990, down to less than 150 today, and the capacity of these fewer refineries, though, has increased slightly, by about 7 percent, so we are producing a little more from fewer refineries.

Congress needs to provide a certain and fair investment climate for the refining industry. Otherwise, they would not be able to expand capacity to meet our gasoline demand. Already, 10 percent of our refined product is produced overseas and imported. These im-

ports are part of a disturbing trend. First, we became dependent on overseas suppliers. Now, our gasoline supplies may soon be in the power of a foreign government as well, not to mention the loss of high-paying U.S. jobs.

So, we need to create an investment climate in the U.S. that will ensure adequate refining capacity that is best for the consumers and energy security, and we still can improve air quality. Reformulated gasoline and other blends are important for public health, saving billions in health care costs, but we cannot keep changing the rules of the game on gasoline formulations. We need a more orderly process.

My position on MTBE has been clear many times in this committee, and I don't want to repeat it—the Federal Government de facto requirement of MTBE with the oxygenate requirement. MTBE has improved public health, but if we slam refiners with defective product lawsuits for a product that was required and clean the air as expected, we send a terrible message to the industry and its investors.

When you discourage investment like that, capacity shortages are likely and consumers feel the hit in their family budgets. Congress should refrain from further tinkering with the number and type of gasoline blends that are now required. Instead, we should repeal the oxygenate requirement and conduct a detailed study on the issue of other different required blend fuels.

In emergencies, RFG and other blends can pose supply issues, but these blends are necessary to improve the air quality in most American cities. If our cars do not do their part to reduce emissions, then larger and heavier emission reduction burdens fall on the manufacturers.

In my home town, industry is struggling with the mandated 85 percent emissions cut as part of a State implementation plan. Without improved blends of gasoline, it would be impossible in Houston to meet the Clean Air Standards. In fact, the Houston area refineries themselves could find it hard to expand without these reductions from car emissions.

Also contributing to lower investment in refining capacity is the uncertain requirements of the New Source Review. The worthy goal of resource review is to achieve continuing pollution control improvements over time, but the changing and competing interpretations of the regulations hurts the goal of pollution control and capacity investment. And I am glad to hear from the EPA today on what they are doing to control emissions in an orderly way, so that the communities, refinery managers, investors know what to expect.

My constituents often live and work in those refineries, and we need to provide clean air and achievable environmental standards for the refineries to maintain U.S. manufacturing jobs while improving our public health and the environment.

Again, thank you, Mr. Chairman.

Mr. HALL. Thank you, Mr. Green. The Chair now is pleased to recognize the chairman of the full committee, the Honorable Joe Barton, for as much time as he needs.

Chairman BARTON. Thank you, Mr. Chairman. And we all want to welcome our former chairman, Mr. Tauzin, back. He's been

working hard this week—even though his choice of ties isn't what it used to be.

Mr. TAUZIN. My wife bought me this tie.

Chairman BARTON. He has lost so much weight, he is pulling out these suits from when he was 30 pounds lighter and 10 years younger.

Mr. HALL. I understand all these committee chairmen get fat and heavy.

Chairman BARTON. I have gained 5 pounds in the last 2 months, there may be something to that. Anyway, thank you, Mr. Chairman, for holding this hearing.

Last month, the House voted on a bill that I had sponsored, H.R. 4517, The United States Refinery Revitalization Act of 2004. That bill passed by a vote of 239 to 192, but it had not been the subject of any hearings, had not gone through regular order, and in the floor debate a number of members of this committee and the general House opposed it on the principle that we had not followed regular order, and I had to agree that was the case.

But after the vote, several members who had voted against the bill because of the procedure, came to me and said that they were interested in working on a bipartisan basis to see if we could craft a bill that would increase refinery capacity, and that they would be willing to help on crafting that bill if we would go through regular order. This hearing is the start of that process, and I want to thank you, Mr. Chairman, for beginning that process.

The lack of refinery capacity needs to be addressed. Demand for refined product outpaces supply by over 10 percent, the differences coming from foreign imports. Domestic refiners are producing flat-out, operating at over 95 percent of capacity. Forecasts show no appreciable increase in refining capacity, all the while the demand is ever increasing.

So, we are starting a process with this hearing today not to have a legislative hearing on a particular bill, but to gather the facts and build a record so that we can craft, as I said earlier, a bipartisan bill.

The panels that are going to appear before us are balanced, and we are going to hear from all sides on this subject. We will hear testimony from the Energy Information Administration, the Environmental Protection Agency, the Federal Trade Commission, the Government Accounting Office, from refiners, consumer groups, distributors, and the private sector in terms of the investment analysts that follow the refinery industry in this country. The information that we gather today hopefully will serve as the basis for future decisions concerning the role that Congress can play legislatively in helping to resolve the refinery capacity problem here in the United States.

I look forward to hearing from the witnesses, and I appreciate their appearance. I look forward to a very positive hearing and, with that, Mr. Chairman, thank you again for putting this hearing together, and I yield back the balance of my time.

Mr. HALL. Thank you, Chairman Barton. The Chair recognizes the gentleman from California, Mr. Waxman.

Mr. WAXMAN. Thank you very much, Mr. Chairman. Today's hearing focuses on refinery capacity issues and State clean fuels re-

quirements. This is ironic because the House has already debated legislation on both these issues. In fact, without ever holding a hearing or a Commerce Committee markup, the House passed a bill that trumped the States' regulation of refinery pollution and weakened the Clean Air Act and the Clean Water Act. This committee process is completely backwards, but I believe it is representative of how the Republican leadership has approached the Nation's energy policy.

I will be blunt. A terrible fraud is being perpetrated upon the American people. The American people are being told that the President's Energy Bill will relieve the Nation's dependence on foreign oil, and it will reduce consumers' energy costs, but the Administration's own analysis shows these assertions are simply not true. President Bush, Majority Leader Tom DeLay, former Chairman Billy Tauzin, Republican members of this committee, have repeatedly stated that the President's Energy Bill will ease our dependence on foreign oil, but the charts that I want to show today from the Energy Information Administration found facts that I want to bring to the attention of the members.

In the first chart, we see that the need for imported crude oil increases by more than 70 percent. Even if the President's plan is enacted, this would result in a record high need for imported oil.

The second chart shows an EIA projection of domestic oil production under the President's Energy Bill. As you can see, the domestic crude oil production will decline by almost 20 percent from 2002 levels even if the Energy Bill is enacted.

This information has been publicly available and unrefuted since February, yet, despite these facts, Republican leaders continue to say that the Energy Bill will significantly reduce dependence on foreign oil, but the statements don't end there. Both the White House and Republican leaders in Congress have resolutely worked to convince the public the Energy Bill will reduce gasoline prices, yet EIA directly refutes these statements, too, projecting that the Energy Bill will actually increase gasoline prices 3 to 8 cents per gallon.

What we need to do instead is to work together to confront the real energy problems we face—the Nation's dependence on oil, global warming, air pollution, and energy security. Powerful industries like the coal industry, the electric utility industry, and the oil and gas companies want to preserve the status quo, or even to roll back important environmental protections, but that takes us in the wrong direction.

We have to look to the future, and our goal has to be to provide our children with a more secure energy future that is based on innovation, efficiency, conservation, and clean energy. Thank you, Mr. Chairman.

Mr. HALL. The Chair recognizes Mr. Shimkus, the gentleman from Illinois.

Mr. SHIMKUS. Thank you, Mr. Chairman. I would love to continue this debate on the National Energy Plan with my friend from California. We worked on the bill. It has a major hydrogen initiative. It brings wind power, clean coal technology—there are so many good things in this Energy Bill that to not move it as is the

case, I think, is the real fraud being perpetrated on our country and our citizens. There is no reason.

But we are here to talk about refineries. You know what? We haven't built a new one in 28 years. People can't believe that. We have not built a new refinery. Now, thank heaven that the industry has been able to ramp up to 98 percent capacity. That is amazing. That is laudable. That should be congratulated. But it also is the fear of huge spikes in gasoline prices with the bulkinization of fuels that we have out there. One refinery goes down, one pipeline gets disrupted, holy heck breaks lose. And we have seen that.

Wisconsin has seen that. Illinois has seen that. So we have to have—we really have to address this issue. I applaud the chairman for bringing the bill to the floor on the refinery bill. It shows you the strength of the argument when you don't go through the process and you still get a bipartisan majority to pass the bill on the floor. It shows that there is a need to address this.

Now, I had some industry folks visit me. They want to pipe heavy Canadian crude oil from western Canada to the Gulf Coast, to get to a refinery that will refine the fuel. I mean, does that make sense? I had another group say they wanted to build an L&G facility in the Bahamas and then pipe the liquefied natural gas into Florida. Now, does that make sense? We lose the jobs. We lose the tech base. We lose the value-added. This is crazy.

So, I hope we have a good hearing on the need to develop and expand the refineries. The only refineries that are going to be expanded, thankfully, are the ethanol refineries, which I applaud. A lot of new ethanol refineries out there, we want to encourage that, but I do think that we ought to have some petroleum-based refineries built in this country. I think that the supply and demand equation works. You limit the supply and you keep the same demand, you have higher prices. We need to increase the supply both of the crude oil and we need to increase the supply of refined products and put competitive market forces on this. We need new refineries. With that, Mr. Chairman, thank you. I yield back my time.

Mr. HALL. Thank you. The Chair recognizes Mr. Doyle, the gentleman from Pennsylvania.

Mr. DOYLE. Thank you, Mr. Chairman. I am going to waive my opening statement and save time for questions.

Mr. HALL. Thank you. The Chair recognizes Ms. Capps.

Ms. CAPPS. I thank the chairman. I guess I am glad that we are holding this hearing on U.S. refineries. I only wish that we were holding it 1 month before instead of 1 month after the House considered H.R. 4517, the Refinery Revitalization Act, but perhaps that would have interfered with one of the theme weeks Republican leadership has lined up. And since the theme weeks are more about showmanship actually than passing good laws, I guess it is understandable that the hearing on this issue comes after we have passed the bill.

If we had held this hearing before we considered H.R. 4517, this committee would have been able to learn about the numerous flaws in the bill. For example, the bill would give the Department of Energy unprecedented authority over all environmental permitting of refineries, creating serious conflicts between the Department of En-

ergy and State, and the Federal agencies charged with protecting our environment.

The premise of the bill is that environmental regulation is limiting refinery expansion, but refining capacity has increased in recent years. Environmental requirements have not prevented that increase. While there has been a decrease in the number of refineries, this seems to be due to increasing market concentration resulting from refinery mergers. Thus, big oil and not environmental laws are to blame for fewer, but bigger, refineries.

But even if environmental permitting requirements were the problem, H.R. 4517 would make the situation worse by wrecking havoc with the well-established partnership in place today. Under this bill, Department of Energy would be given lead authority over environmental permits, and would be able to overrule permit denials by other State and Federal agencies. The Department of Energy, I submit, lacks the expertise in interpreting or implementing environmental laws because its mission is not focused on environmental protection. That is why we have checks and balances. While this bill is no doubt supported by the refineries, it is not supported by anyone with a stake in environmental protection. All the major environmental organizations oppose this bill.

This bill also creates a special consultation process for industry. Before any other parties would even know a permit is being planned, H.R. 4517 would require that DOE provide any permit applicant with a chance to meet with the permitting agencies and obtain an informal reading regarding the agency's plan for granting the permit. This would give the inside track to the applicant over groups with public health and environmental concerns.

Finally, DOE would be able to shape the record and the timing and the procedure for granting permits. That power, in itself, is highly significant, since the major part of permit evaluation is whether the permittee has supplied sufficient information and, in many cases, the environmental statutes and regulations specify precise permit content. Under the bill, DOE would be allowed to determine that "such data as the Secretary considers necessary had been submitted," and move to permit issuance in 6 months or less. That would allow DOE to move a permit forward, even where a permit applicant has clearly failed to meet fundamental requirements for basic information. Simply put, H.R. 4517 is a bad bill that should never have passed the House. With any luck, that is the last we will see of it.

Mr. Chairman, high gas prices are a serious problem in this country, and they have gone up again. I should know because gas prices in my district are perhaps the highest in the Nation. Congress should be passing legislation to help bring down prices by reducing our energy use, promoting alternative and renewable energy sources. H.R. 4517, like H.R. 6, was just another bad bill that wouldn't help make America any more energy independent. I yield back my time.

Mr. HALL. Thank you, Ms. Capps.

Ms. CAPPS. Thank you for letting me go over.

Mr. HALL. You men and women heard the same buzzer and bells that we heard. There is a vote on. There will be a couple of votes after that time. But we have one of the most outstanding chairmen

in the history of the Energy and Commerce Committee in our presence. We are going to recognize Billy Tauzin. He is Chairman Emeritus or Chairman-in-Exile, or something—I don't know what he is—but whatever he wants to be, we recognize him, and then we will recess for 30 minutes.

Mr. TAUZIN. Thank you, Mr. Chairman. I will be very brief. First, I want to give you good news. As you know, even though the Energy Bill is stalled on the other side, one of the key provisions that we inserted into it with the help of the Resource Committee was a provision to increase incentives for deep drilling in the shallow Gulf of Mexico, off the coast of Louisiana and Texas, in particular. As you know, the bill hasn't moved out of the Senate, but the Administration moved forward with an Executive Order on that very same principle, and in March of this year we held a lease sale in the Gulf of Mexico. The United States got $364 million for over 542 tracts—61 percent of those tracts were in the shallow, 200 meter or less, areas, and they are going after the deep gas that the provisions of the bill predicted they would go after. We simply encouraged it with the same royalty relief program we extended to deep drilling, in the deeper Gulf. So, it is already working, Mr. Waxman. At least one provision that we anticipated would develop new resources of natural gas for America is already underway, and that is good news.

I just want to leave you with one thought. I am going to end my service here in a few months, after 25 years in Congress. Before I started my service in Congress, the last refinery was built in my district in Garyville—28 years ago. We haven't built one since. And for those of you who think that we have simply expanded enough capacity in existing refineries to make up the difference—the facts are pretty stubborn things—these are the facts. Refinery capacity peaked in 1981, a year after I got here. That was the peak. And we had surplus capacity that year of over 5.5 million barrels per day. We have got almost no surplus capacity today, and demand continues to rise.

So, whether or not we import more oil, or we don't import more oil, or we produce more oil in this country, or we use a strategic petroleum reserve for purposes or not for purposes that you support, the fact of the matter is that our refinery capacity peaked in 1981 and demand is still growing. We built 750 million new vehicles in the last 25 years, and we haven't expanded our refining capacity.

Now, however you feel about energy in America, whether you think we ought to produce more or depend more on foreign sources, it doesn't make a whole lot of sense not to process it here. Instead, we are beginning to build a foreign dependence on processing our fuel, and that probably is the most dangerous dependency we could ever build for our country.

So, as I leave you in the next few months, I would just urge you to work together in a bipartisan fashion and find an answer, whatever that answer may be, to make sure our refining capacity is increased in this country, regardless of what else you do in energy, to make sure we have some surplus capacity so, as Mr. Shimkus pointed out, when one refinery goes down, one pipeline goes down, we don't have a shock effect on consumers, as we saw in the Mid-

west, in Milwaukee and Chicago, where prices spiked so dramatically because one refinery went down, one pipeline went down, one ship blocked the harbor in Lake Charles, Louisiana. That ought to not happen in this country. Whatever you feel about energy, we at least ought to process more here in this country as we need it, and I would urge you to look at those facts. They are stubborn. How we fix it is debatable, but the facts won't go away. Our refining capacity is flat, our demand is rising, that is dangerous. And this country faces enough danger that we don't need to create new ones for us.

Thank you very much, Mr. Chairman. And I will have a chance before I leave officially, but I didn't have a chance yet in a committee hearing to say how much, Ralph, we welcome your service on this committee as chairman of this Energy Subcommittee, and I wanted to extend my congratulations to your ranking member. You have got a great team here working on Energy together.

Mr. Green, we have been together for a long time. Somehow, some way, we have got to get past some of these awful divides that separate us from finding some answers. We have got to find some answers for this country. I would ask you, please, to think as Americans rather than Democrats and Republicans, when it comes to this one, and find some answers before it is too late. We shouldn't have commissions 1 day red-faced, looking back, like a 9/11 Commission, wondering what we could have done before it was too late. We ought to do it now before it is too late. God bless you on your service to the country, Ralph.

And to the new chairman, Mr. Barton, I extend my greatest commendations. You are doing a great job, and I wish you well, sir. I love this committee more than you know, and I wish you the best of luck as we move forward in the future. Keep it bipartisan, keep it American. That is how I tried to help build it when I took over. Keep it that way. Find some answers. I have watched you on C-SPAN from the hospital over the last 6 months. It is not pretty. It is too partisan. Americans are watching you. Try to think as Americans for a while, even through this election cycle, I think that is the best recommendation I can leave you with, particularly when it comes to energy security because everything else in our economy depends upon that. Thank you, Mr. Chairman.

Mr. HALL. Thank you very much. You and I remember, and maybe some others here, when we asked Mr. Waxman and Mr. Dingell, who were at loggerheads over the Clean Air Act, to go into a room one morning at 9 o'clock, and they came out late that night with an answer. Mr. Waxman is capable of working with you, and we have got to work together to find this. It is not a Republican or Democratic matter, it is an American matter. It might keep our youngsters off of a troop ship. That is what we have to do.

Mr. GREEN. Mr. Chairman, I want to briefly thank Chairman Tauzin for many years of friendship, and hopefully we can make it bipartisan.

Mr. HALL. The subcommittee will recess for 30 minutes.

[Brief recess]

Mr. HALL. We have our witnesses back in place, and the Chair notes the presence of the former chairman of the Energy and Com-

merce Committee, long-time chairman, the venerable John Dingell. I am glad to recognize you, Mr. Dingell.

Mr. DINGELL. Mr. Chairman, I thank you, you are very gracious. Mr. Chairman, I think this is a useful hearing, and I am pleased that it is being done. I want to express to you the appreciation of this side for the cooperation you have shown with respect to witnesses.

The subject matter of our discussion today is an important one. It is also a very complex topic that deserves the committee's attention. Because of its complexity, it us a topic that demands a thorough understanding and a full record before any attempt is made to legislate. On that note, I would observe with some sadness that it is regrettable that we find ourselves holding a hearing some 2 weeks after the leadership took two bills to the House floor, one on refineries and the other on boutique fuels without ever having a single hearing or markup.

This is backwards. The cart is in front of the horse. It is a style of legislating that reflects poorly on this committee, and one which is inconsistent with the practices of this committee over the years. I hope we will not repeat that unfortunate event again.

Gas prices have been at record highs for several months now, and while the Energy Information Agency reports increases have abated somewhat to a national average of $1.89 per gallon, statistical drops in the price of gasoline are of little comfort to the consumers in my State who continue to pay more than $2 per gallon. I know other States have similar situations.

While crude prices have dipped from their June high of $42 a barrel to down to $35 per barrel, EIA states they are on the rise again and, as of yesterday, were hovering at around $40. I asked the Bush Administration some months ago to aggressively jawbone OPEC to open the spigots, but it seems the Administration has chosen to ignore that advice. Of course, refinery capacity does have an effect on the ultimate price to consumers. It is a well known fact that the number of U.S. refineries has declined steadily from the early 1980's through the 1990's. We should indeed examine this development, as well as the reasons why it has occurred, as well as the fact that despite the decline in the number of refineries, the refinery capacity in this country has, in fact, increased, and is projected to continue doing so, as well as having noted that refinery utilization has increased as well.

The fact remains that the refining industry operates in a tight market of its own making. Some of this is said by consumers and consumer advocates to be done in order to maximize profits and minimize underused capacity. From the industry's perspective, this is simply good business. Whether it is good for consumers I leave to them to judge, but I don't think you'll find much agreement that it helps them.

I note that the GAO will be testifying today concerning its findings on mergers and acquisitions in the refining industry. This is an important question. And the GAO will be talking about how these matters have led to increased market concentration and higher prices. The decline in the number of refineries is the principal reason cited for bringing H.R. 4517 to the floor outside of the regular order. That bill would have nullified three decades of expertise

that EPA has acquired regarding environmental permitting, and transferred that function to the Secretary of Energy, under the theory that we would see an increase in refinery reopenings.

On June 22, I wrote to EPA Administrator Leavitt, to determine the number of permits that were being delayed and would reopen closed refineries, but I have yet to receive a response. Perhaps the committee could assist me in procuring that response. We have a witness from EPA here today, and perhaps he will provide one for us. Certainly, I will ask him for the answer to those questions and for a response to this letter.

At this point, Mr. Chairman, I ask unanimous consent that my letter be inserted in the record, along with EPA's response when, and if, received.

Mr. HALL. The letter and the response will be entered, without objection.

[The information referred to follows:]

W.J. "BILLY" TAUZIN, LOUISIANA
RALPH M. HALL, TEXAS
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CLIFF STEARNS, FLORIDA
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C.L. "BUTCH" OTTER, IDAHO
JOHN SULLIVAN, OKLAHOMA

BUD ALBRIGHT, STAFF DIRECTOR

ONE HUNDRED EIGHTH CONGRESS

U.S. House of Representatives
Committee on Energy and Commerce
Washington, DC 20515–6115

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June 22, 2004

The Honorable Michael R. Leavitt
Administrator
Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001

Dear Administrator Leavitt:

Last week the House debated whether environmental permitting delays are keeping a large number of old refineries which have closed over the past twenty years from reopening to assist in producing gasoline for the American public. Therefore, I request that you identify whether any of the refineries listed in the enclosed attachment have permit applications pending with the Environmental Protection Agency or authorized or delegated states under the Clean Air Act, the Clean Water Act, the Resource Conservation and Recovery Act, the Safe Drinking Water Act, or the Toxic Substances Control Act. I am interested only in permit applications that are necessary to reopen or re-start the refinery, and not those that relate to permanent closure of the facility. If any such permit application is pending for these refineries, please identify the date of the permit application, the current status of the application, and the expected date of a decision on the permit application.

I request a response to this request by no later than Tuesday, July 6, 2004. Should you have questions, please contact Richard Frandsen or Bruce Harris of the Democratic Committee staff at (202) 225-3641.

Thank you for your cooperation with this request.

Sincerely,

JOHN D. DINGELL
RANKING MEMBER

Enclosure

cc: The Honorable Joe Barton, Chairman
Committee on Energy and Commerce

The Honorable Ralph M. Hall, Chairman
Subcommittee on Energy and Air Quality

The Honorable Rick Boucher, Ranking Member
Subcommittee on Energy and Air Quality

CLOSED U.S. REFINERIES SINCE 1980

Sources: Energy Information Administration and National Petroleum Council

Date of Closing	Refinery Name	Location
1980	Yetter Oil Co.	Colmar, IL
1980	Bi-Petro Refining Co., Inc.	Pana, IL
1980	Consumers Power Co.	Marysville, MI
1981	Carbonit Refinery Co.	Hearn, TX
1981	Texas Standard Refining, Inc.	Houston, TX
1981	Adobe Refining	La Blanca, TX
1981	Texas Refining Co.	Midland, TX
1981	Glenrock Refinery, Inc.	Glenrock, WY
1981	Southwestern Refining Co., Inc.	La Barge, WY
1981	Southland Oil Co.	Yazoo City, MS
1981	ATC Petroleum, Inc.	Newington, NH
1981	Southern Union Refining Co.	Monument, NM
1981	Mobil Oil Corp.	Buffalo, NY
1981	Gulf Oil Corp.	Toledo, OH
1981	Amoco Oil Co.	Wood River, IL
1981	Indiana Refinery, Inc.	Princeton, IN
1981	Gulf Oil Corp.	Venice, LA
1981	Dow Chemical U.S.A.	Bay City, MI
1981	Conoco, Inc.	Wrenshell, MN
1981	Road Oil Sales Inc.	Bakersfield, CA
1981	Manatee Energy Co.	Port Manatee, FL
1981	Energy Development	Crossville, IL
1981	Texaco Inc.	Lockport, IL
1981	Wireback Oil Co.	Plymouth, IL
1981	Quad Refining Corp.	Bakersfield, CA
1982	Dillman Oil Recovery, Inc.	Oblong, IL
1982	Energy Cooperative, Inc.	E. Chicago, IL
1982	Indus Fuel and Asphalt Co.	Hammond, IN
1982	Mid-America Refining Co.	Chanute, KA
1982	Philips Petroleum Co.	Kansas City, KA
1982	E-Z Serve, Inc.	Shallow Water, KA

CLOSED U.S. REFINERIES SINCE 1980

Sources: Energy Information Administration and National Petroleum Council

Date of Closing	Refinery Name	Location
1982	Bayou State Oil Corp.	Hosston, LA
1982	Evangeline Refining	Jennings, LA
1982	Shepard Oil Co.	Jennings, LA
1982	T & S Refining Inc.	Jennings, LA
1982	Shulze Processing Inc.	Tallulah, LA
1982	Amoco Oil Co.	Baltimore, MD
1982	Texas American Petrochemical Inc.	W. Branch, MI
1982	Natchez Refining	Natchez, MS
1982	Amoco Oil Co.	Sugar Creek, MO
1982	CRA, Inc.	Scottsbluff, NB
1982	Giant Industries, Inc.	Farmington, NM
1982	Northland Oil & Refining	Dickinson, ND
1982	Okmulgee Refg.	Okmulgee, OK
1982	Rio Grande Crude Refining	Brownsville, TX
1982	Rio Grande Crude Recovery Systems	Brownsville, TX
1982	Dow Chemical U.S.A.	Freeport, TX
1982	Brio Refining Co.	Friendswood, TX
1982	Bronco Refining Co.	Houston, TX
1982	Copana Refining Co.	Ingleside, TX
1982	Tipperary Corp.	Ingleside, TX
1982	Eagle Refining Corp.	Jacksboro, TX
1982	Longview Refining Co.	Longview, TX
1982	Placid Oil Co.	Mt. Belvieu, TX
1982	Clinton Manges	Palestine, TX
1982	Quitman Refining Co.	Quitman, TX
1982	Wickett Refg. Co.	Wickett, TX
1982	United Independant Oil Co.	Tacoma, WA
1982	Elk Refining Co.	Falling Rock, WV
1982	Texaco Inc.	Casper, WY
1982	Husky Oil Co.	Cody, WY
1982	Sage Creek Refining Co.	Cowley, WY

CLOSED U.S. REFINERIES SINCE 1980

Sources: Energy Information Administration and National Petroleum Council

Date of Closing	Refinery Name	Location
1982	C & H Refining	Lusk, Wy
1982	Glacier Park Co.	Osage, WY
1983	Arizona Fuels Inc.	Fredonia, AZ
1983	Demenno Kerdoon	Compton, CA
1983	Mallard Resources, Inc.	Gueydon, LA
1983	McTan Refinery Corp.	St. James, LA
1983	Hudson Refining Co. Inc.	Cushing, OK
1983	Champlin Petroleum Co.	Enid, OK
1983	Quaker State Oil Refining Corp.	Emlenton, PA
1983	Petraco Valley Oil & Refining Corp.	Brownsville, TX
1983	Thriftway Co.	Graham, TX
1983	Shore, Inc.	Kilgore, TX
1983	Erickson Refg. Corp.	Pt. Neches, TX
1983	Indep. Refining Corp.	Winnie, TX
1984	Eco Petroleum, Inc.	Long Beach, CA
1984	Anchor Refg.	McKittrick, CA
1984	Ashland Oil Inc.	Louisville, KY
1984	U.S.A. Petrochemical Corp.	Ventura, CA
1984	Celeron Oil & Gas Co.	Mermentau, LA
1984	Port Petroleum	Stonewall, LA
1984	Southern Union Refining Co.	Lovington, NM
1984	Caribou-Four Comers	Farmington, NM
1984	Ashland Oil Inc.	Buffalo, NY
1984	Ashland Oil Inc.	Findlay, OH
1984	Tonkawa Refg. Co.	Arnett, OK
1984	Oklahoma Refining Co.	Cyril, OK
1984	Tosco	Duncan, OK
1984	Tosco	Bakersfield, CA
1984	Tesoro Petroleum Corp.	Carrizo Springs, TX
1984	Quintana Petrochemical Co.	Corpus Christi, TX
1984	Eddy Refining Co.	Houston, TX

CLOSED U.S. REFINERIES SINCE 1980

Sources: Energy Information Administration and National Petroleum Council

Date of Closing	Refinery Name	Location
1984	Mid-Gulf Energy Corp.	Ingleside, TX
1984	Dorchester Refining Co.	Mt. Pleasant, TX
1984	Caribou-Four Comers	Woods Cross, UT
1985	Coastal Petroleum Refiners, Inc.	Bakersfield, CA
1985	Golden Eagle Refining	Carson, CA
1985	Texaco Refg. & Mktg, Inc.	Lawrenceville, IL
1985	B-T Energy Corp.	Louisville, KY
1985	Kenco Refining Inc.	Wolf Pt., MT
1985	Allied Materials Corp.	Stroud, OK
1985	Ashland Oil Inc.	Freedom, PA
1985	American Refg. Group, Inc.	Indianola, PA
1985	Conoco, Inc.	Alvin, TX
1985	Texaco Refining & Marketing	Amarillo, TX
1985	Tropicana	Fort Worth, TX
1985	Flint Chemical Co.	San Antonio, TX
1985	Damson Gas Processing Corp.	White Deer, TX
1985	Morrison Petroleum Co.	Woods Cross, UT
1986	Chevron Corp.	Bakersfield, CA
1986	Gladieux Refinery, Inc.	Ft. Wayne, IN
1986	Chevron Corp.	Baltimore, MD
1986	Chevron Corp.	Cincinnati, OH
1986	Petromax Refg. Co., Inc.	Houston, TX
1987	MacMillan Petroleum Co.	Norphlet, AR
1987	Sabre Refining, Inc.	Bakersfield, CA
1987	Beacon Oil Co.	Hanford, CA
1987	Western Oil & Refg.	Long Beach, CA
1987	Clark Oil & Refining Corp.	Mt. Airy, LA
1987	Lakeside Refining Co.	Kalamazoo, MI
1987	Flying J Petroleum Inc.	Willston, ND
1987	Virginia Oil & Refg. Co. Inc.	Jonesville, VA
1988	Silver Eagle Oil Co.	La Barge, WY

CLOSED U.S. REFINERIES SINCE 1980

Sources: Energy Information Administration and National Petroleum Council

Date of Closing	Refinery Name	Location
1988	Texas Napco Inc.	St. James, LA
1988	Flying J. Petroleum, Inc.	Cut Bank, Montana
1988	Liquid Energy Corp.	Bridgeport, TX
1988	Amber Refining, Corp.	Ft. Wayne, IN
1988	Mountaineer Refining Co., Inc.	La Barge, Wyoming
1988	GAMXX Energy Inc.	Theodore, AL
1988	West Coast Oil Co.	Oildale, CA
1988	Seminole Refg. Corp.	St. Marks, FL
1988	Motor Oils Refining Co.	McCook, IL
1988	Kentucky Oil & Refining Co.	Betsey Layne, KY
1988	OGC	Egan, LA
1988	Texas Napco Inc.	St. James, LA
1988	Flying J Petroleum Inc.	Cut Bank, MT
1989	Warrior Asphalt Refining Corp.	Holt, AL
1989	Newhall, Refining Co., Inc.	Newhall, CA
1989	Conoco, Inc.	Egan, LA
1989	City Gas & Transmission Corp.	Wilmington, NC
1989	Donna Refg. Partners, Ltd.	Donna, TX
1989	Unocal Corp.	Nederland, TX
1991	Vulcan Refining Co.	Cordova, AL
1991	Gibson Oil & Refing Co.	Bakersfield, CA
1991	Eagle Refining Co.	Jacksboro, TX
1991	Polo Chemical Inc.	San Leon, TX
1992	Chevron USA Inc.	Kenal, AK
1992	Shell Oil Co.	Carson, CA
1992	Inter-Coastal Energy Services Co.	Troy, IN
1992	Sabine Resources Group	Stonewall, LA
1993	Amoco Oil Co.	Casper, WY
1993	Eco Asphalt Inc.	Long Beach, CA
1993	Fletcher Oil & Refining Co.	Carson City, CA
1993	Golden West Refining Co.	Sante Fe Springs, CA

CLOSED U.S. REFINERIES SINCE 1980

Sources: Energy Information Administration and National Petroleum Council

Date of Closing	Refinery Name	Location
1993	Farmland Industries Inc.	Phillipsburg, KS
1993	GNC Energy Corp.	Greensboro, NC
1993	Thriftway Co.	Bloomfield, NM
1993	Quakerstate Oil Refining Corp.	Smethport, PA
1993	Leal Petroleum Corp.	Nixon, TX
1993	Longview Refining Associates	Longview, TX
1993	Rattlesnake Refining Corp.	Wickett, TX
1993	El Paso Refining Co. Ltd.	El Paso, TX
1993	Primary Oil and Energy Corp.	Chester, WA
1994	Phoenix Refining Co.	Saint Mary's, WV
1994	Sunbelt Refining Co.	Coolidge, AZ
1994	Landmark Petroleum Co.	Frula, CO
1994	Rock Island Refining Co.	Indianapolis, IN
1994	Coastal	Augusta, KS
1994	Coastal	Wichita, KS
1994	Dubach Gas Co.	Dubach, LA
1994	Crystal Refining Co.	Carson City, MI
1995	Cibro Petroleum Products Inc.	Albany, NY
1995	Chemoil Refining Co.	Long Beach, CA
1995	Coastal	El Dorado, KS
1995	Amerada Hess	Purvis, MS
1995	Chevron	Philadelphia, PA
1997	Pennzoil Producing Co.	Roosevelt, UT
1997	Powerine Oil Co.	Sante Fe Springs, CA
1997	Sunland Refining Co.	Bakersfield, CA
1997	Laketon Refining Corp.	Laketon, IN
1997	Total Petroleum Inc.	Arkansas City, KS
1997	Dubach Gas Co.	Lisbon, LA
1997	Petro Source Resources Inc.	Vicksburg, MS
1997	Barrett Refining Corp.	Thomas, OK
1997	Southwest Refining Co.	Corpus Christi, TX

CLOSED U.S. REFINERIES SINCE 1980

Sources: Energy Information Administration and National Petroleum Council

Date of Closing	Refinery Name	Location
1999	Pacific Refining Co.	Hercules, CA
1999	American Intern Refinery, Inc.	Lake Charles, LA
1999	Canal Refining Co.	Church Point, LA
1999	Petrolite Corp.	Kilgore, TX
1999	Pride Refining Co.	Abilene, TX
1999	Shell Oil Co.	Odessa, TX
1999	Sound Refining Inc.	Tacoma, WA
2000	Calumet Lubricants Co. LP	Rouseville, PA
2000	Berry Petroleum Co.	Stephens, AR
2000	Chevron USA, Inc.	Richmond Beach, WA
2001	Premcor Refining Group	Blue Island, IL
2002	Premcor Refining Group	Hartford, IL
2002	American International	Lake Charles, LA
2002	Foreland Refining Corp.	Tonapah, NV
2002	Tricor Refining LLC	Bakersfield, CA
2002	Chevron Phillips Chem PR Core	Guayama, PR

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

JUL 27 2004

OFFICE OF
AIR AND RADIATION

The Honorable John D. Dingell
Ranking Member
Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC 20515-6115

Dear Congressman Dingell:

Thank you for your letter of June 22, 2004, to Administrator Leavitt, in which you request information regarding the closures of over two hundred oil refineries that were permitted under the Clean Air Act (CAA), the Clean Water Act, the Resources Conservation and Recovery Act, the Safe Drinking Water Act, and the Toxic Substances Control Act.

The air permitting of refineries under the CAA is generally administered by various state and local agencies across the country. Through its Regional Offices, the Environmental Protection Agency (EPA) oversees the permit programs and is usually aware of major permitting actions. Upon review of your request and consulting as appropriate with state and local agencies, the EPA Regions have informed me that they are not aware of any pending air permits for the restart of the oil refineries on your list.

This letter serves as an interim response to your request in that it responds to the CAA portion of your request. Please note, however, that we will update you on the permitting status for the other statues you reference once all of the information is compiled. We hope to forward that response to you in the very near future.

Again, thank you for your letter. If you have further questions, please feel free to contact me or your staff may contact Catherine Sulzer, in EPA's Office of Congressional and Intergovernmental Relations, at (202) 564-2464.

Sincerely,

Jeffrey R. Holmstead

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C. 20460

SEP 29 2004

OFFICE OF CONGRESSIONAL AND
INTERGOVERNMENTAL RELATIONS

The Honorable John Dingell
United States Congress
Washington, DC 20515

Dear Congressman Dingell:

I am writing to follow-up on Jeff Holmstead's previous letter of July 21, 2004, which served as an interim response to your request regarding the closure of over two hundred oil refineries that were permitted under the Clean Air Act, the Clean Water Act (CWA), the Resources Conservation and Recovery Act (RCRA), the Safe Drinking Water Act (SDWA), and the Toxic Substances Control Act (TSCA). Mr. Holmstead's letter indicated that the Environmental Protection Agency (EPA) Regions reported that they are not aware of any pending permits for the restart of oil refineries on your list.

Similar to the CAA, the permitting of refineries under CWA, RCRA, SDWA, TSCA is generally administered by various state and local agencies across the country. Through its regional offices, EPA oversees the permit programs and is usually aware of major permitting actions. Upon further review and consultation with the appropriate state and local agencies, we are not aware of any pending permits under CWA, RCRA, SDWA, and TSCA for the restart of oil refineries on your list.[1]

Again, thank you for your letter. If you have further questions, please feel free to contact me or your staff may contact Catherine Sulzer in EPA's Office of Congressional and Intergovernmental Relations at (202) 564-2464.

Sincerely,

Charles L. Ingebretson
Associate Administrator

[1] Please note that the Clark Oil and Refinery Corporation, which is no longer a refinery but a bulk truck terminal, is currently filing for a National Pollutants Discharge Elimination Systems permit under the Clean Water Act.

Mr. DINGELL. I have also been long concerned about the balkinized fuel supply and the effect that it has on the fungibility of gasoline and the prices consumers pay at the pump. This is a serious issue. While the issue of boutique fuel does need examination, we must remind ourselves that we again confront a question of balancing important environmental benefits that can be achieved and that none of us want to see eliminated versus cost, convenience, and perhaps a better way of distributing our fuels to our country.

I look forward to a complete hearing today and, again, Mr. Chairman, I express my thanks to you for your courtesy to me. I yield back the balance of my time.

Mr. HALL. Thank you, Mr. Dingell. The Chair recognizes Mr. Whitfield of Kentucky, if he would like to make an opening statement.

Mr. WHITFIELD. Mr. Chairman, I am going to waive my opening statement.

Mr. HALL. I know you were the earliest here because you and I thought this started at 10 o'clock and we were both here.

The Chair recognizes Mr. Issa of California.

Mr. ISSA. I waive my opening statement, Mr. Chairman.

Mr. HALL. The Chair recognizes Mr. Allen of Maine.

Mr. ALLEN. Thank you, Mr. Chairman, for holding this hearing on the status of the U.S. refining industry. I am reminded of the old adage, "Shoot first and ask questions later." Exactly 1 month ago, the House passed H.R. 4517, the U.S. Refinery Revitalization Act. Now we will ask some questions.

Mr. Chairman, I speak today with concern about the direction of the Energy and Commerce Committee. We have taken legislation to the House floor without a committee markup. We pushed partisan legislation that abandons $15 billion in the Nuclear Waste Fund and fails to address the funding crisis that Yucca Mountain faces at the hands of appropriators. Last week, we had a hearing on the U.N. Oil for Food Program, at which the State Department failed to show up. Just Tuesday, the State Department witness left a hearing of the Environment and Hazardous Materials Subcommittee without permission, before she had responded to questions.

We face real challenges in this country, and I believe this committee needs to lead the Congress in addressing them. Refineries are significant emitters of volatile organic compounds, a precursor pollutant to ground-level ozone. The facilities pose a threat to human health and are regulated under the Clean Air Act. As I read it, H.R. 4517 undermines Clean Air Standards at refining facilities. The bill lowers the standard at some facilities, makes enforcement of the Clean Air Act optional, and hands over the task of environmental protection from the Environmental Protection Agency to the Department of Energy.

The bill states, "The best available control technology, as appropriate, shall be employed on all refineries located within a refinery revitalization zone."

In places where the air already contains unhealthy levels of pollution, the Clean Air Act holds new and modified refineries to an even higher standard described as the "lowest achievable emissions

rate," and also requires offsetting emissions reductions for new sources of pollution. The weaker standard and no pollution offsets would lead to more pollution than current health-based standards permit.

Furthermore, H.R. 4517 requires refineries to use best available control technology only as appropriate. Does this legislation authorize the Secretary of Energy to label best available control technology inappropriate in certain circumstances? If so, does the legislation permit the Secretary to selectively enforce the Act?

Finally, H.R. 4517 would place the Secretary of Energy in charge of the permitting process, the official record, and the only environmental review document. Even if EPA's experts conclude that a proposed refinery project fails to comply with the substantive safeguards set forth in the Clean Air Act, the Secretary of Energy may issue the necessary authorization anyway. Under the law, EPA's three decades of expertise would be supplanted by an agency with no experience enforcing the Clean Air Act.

Mr. Chairman, our former chair, Mr. Tauzin, a few moments ago before the break, urged us to think as Americans and not as Republicans and Democrats. I believe we will get there when we have legislation in front of us that deals not only with supply, but that significantly reduces demand. The evidence simply does not support the Clean Air Act as at fault for rising gas prices.

Neither H.R. 4517 nor the so-called Gas Price Reduction Act address the real causes of increased oil price. They do not, for example, address market concentration, create stability in the Middle East and other oil producing regions, help families increase the efficiency of their home thereby reducing oil use, require or create incentives to increase fuel efficiency in our vehicle fleet which is at its lowest level since 1980, invest in hybrid or hydrogen technology, extend the tax breaks for the purchase of high efficiency vehicles, end the tax break for Hummers and other large SUVs, reduce heavy truck idling, or improve air traffic management.

I hope that this hearing allows us to go back to the drawing board. Supply strain and exploding demand are both driving prices. To address price issues, we need to stabilize supply and reduce demand, and when we do both with equal measure, then I think we will be thinking as Mr. Tauzin urged us, to think as Americans and not as Republicans and Democrats. Mr. Chairman, I thank you and yield back.

[Additional statement submitted for the record follows:]

PREPARED STATEMENT OF HON. CHARLIE NORWOOD, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF GEORGIA

Thank you, Mr. Chairman.

I take great interest in today's hearing and would like to commend you, Mr. Chairman, for allowing the Subcommittee to investigate the status of our country's refining industry.

The citizens of the Ninth District of Georgia, along with others across the country, want to know what we in Congress are doing to help lower their gas prices. I wish there was a quick fix, but the facts are clear that there is no such thing.

Tapping into our national oil resources, such as the one in the Arctic National Wildlife Refuge, will not guarantee lower gas prices unless we improve our refinery capabilities as well.

There are currently 149 refineries in the U.S., operating in 33 states. Total refining capacity is approximately 17 million barrels per day. Total domestic demand for crude oil stands at 20 million per day.

While we do our best to combat high gas prices in the present we must also prepare for demand in the future. U.S. gasoline consumption is projected to rise to 13.3 million barrels per day by 2025, up from 8.9 million barrels per day currently.

The refining industry is operating at around 95 percent capacity, compared with an average of 82 percent operating capacity for other industries.

I was pleased to support Chairman Barton's legislation, H.R. 4517, the Refinery Revitalization Act, on the House floor in mid-June. This well crafted legislation includes our continued dedication to ensuring that the environment is protected. This bill will require an accelerated review and approval of all regulatory approvals and will not waive or diminish any existing environmental, siting or other regulations.

Also, it goes without saying I am a big supporter of the Energy Bill, which continues to linger over in the other body.

Mr. Chairman, I am greatly looking forward to the testimony of our witnesses today as they lend us their expertise on the state of the refining industry. With that, I thank you for this time and I yield back.

Mr. HALL. All right. Time has expired, and we now go to the panel. We hope you are educated on what we think, and can now give us the facts of life. Mr. Caruso, Administrator of Energy Information Administration, Department of Energy, always helpful, and thank the Department for always showing up when we ask you for help over here.

I think Chairman Barton went through all you before, but Jeffrey Holmstead, Assistant Administrator for Air and Radiation, Environmental Protection Agency; Jim Wells, Director, Natural Resources and Environment, Government Accountability Office, and General Counsel for the Federal Trade Commission, Bill Kovacic. It is a great panel, and at this time we would hope you would generalize on your testimony and stay as close to 5 minutes—but not hold you to that—as you can to where we can get this hearing over with maybe before milking time tonight.

STATEMENTS OF GUY F. CARUSO, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY; HON. JEFFREY R. HOLMSTEAD, ASSISTANT ADMINISTRATOR FOR AIR AND RADIATION, ENVIRONMENTAL PROTECTION AGENCY; JIM WELLS, DIRECTOR, NATIONAL RESOURCES AND ENVIRONMENT, GOVERNMENT ACCOUNTABILITY OFFICE; AND WILLIAM E. KOVACIC, GENERAL COUNSEL, FEDERAL TRADE COMMISSION

Mr. CARUSO. Thank you, Mr. Chairman, and thank you, members of the committee, for asking the Energy Information Administration to present its outlook for the refinery situation in the U.S. Certainly, as we have heard repeatedly, it is appropriate at this time, with high prices and tight capacity, to discuss this issue.

Just this morning, WTI, West Texas Intermediate crude, opened up at $41 per barrel. On Monday, the retail gasoline price average was released at $1.92. And the reasons why prices are high, of course, are multifold.

While refining capacity is an exacerbating factor in this outlook, it is not the primary cause of the current high gasoline prices. Robust economic growth has led to strong global energy demand, particularly oil, demand. Crude oil capacity around the world is operating close to 99 percent, and inventories are low. But the lack of extra refining capacity will certainly make it more difficult to rebalance this market, once the additional crude is made available. And, clearly, the volatility in this market—the low refinery capacity and tight operating conditions are certainly adding to volatility,

and they are reducing the cushion that we would have to respond to any changes in supply or demand.

There are charts available to the committee, and the first one shows that we are consuming about 20 million barrels a day of oil in the United States, about 84 percent of that is from our domestic refineries. Another 9 percent or so is from natural gas source products, and then ethanol and other oxygenates 2 percent, and net product imports about 5 percent.

The fact that we are now experiencing tightness in refinery capacity is a relatively new phenomenon. During the mid 1970's to mid 1990's, we actually had surplus capacity, but since that time, many small, less-efficient, refineries have shut down, and, as has been mentioned, the last grassroots refinery was built in 1976.

Even with these shutdowns and no new refineries, total capacity has increased and trended upward as operating capacity has expanded at existing facilities, and has helped meet increasing demand. From 1997 to 2003, demand increased in this country by 1.4 million barrels a day and refinery capacity at existing facilities had a net increase of 1.2 million barrels a day, which is the equivalent of adding one medium-sized refinery per year. However, it wasn't enough, and net product imports have increased by about 500,000 barrels a day since that time.

As we look ahead to the next 10 and 20 years, we are projecting that increase in demand in products in this country will be about 4 million barrels a day in a 10-year period up to 2013, and that we are going to need an additional 20 percent capacity or product imports to fill that need.

EIA projects that the United States will see both increases in refinery capacity and product imports, perhaps as much as 3 to 4 million barrels a day of refinery capacity, and this of course remains uncertain, as we have heard from some of the statements, as to whether some of these investments will actually be made in a timely fashion. There is a great deal of uncertainty with respect to the return-on-investment in this sector of the economy and the requirements that will be imposed for environmental and other reasons, as well as siting issues.

So, we will need substantial increased refinery capacity to meet this kind of outlook, and whether it will be domestic refining or more imports depends on a number of the factors that we will be talking about in this hearing.

On the import side, clearly there is uncertainty because of tightness on a global basis in refining capacity. The increasing requirements that more stringent specifications be met by foreign refiners, and we have seen some evidence that the current tightness has limited, to a small extent, imports this year, and of course that would mean that we would have fewer options if this continues.

As we look ahead, both U.S. refining capacity and product imports will play very important roles in meeting our needs, and clearly the work of this committee and the Congress will play an important role in meeting those objectives.

Thank you, Mr. Chairman. I would be pleased to answer questions at the appropriate time.

[The prepared statement of Guy F. Caruso follows:]

PREPARED STATEMENT OF GUY F. CARUSO, ADMINISTRATOR, ENERGY INFORMATION ADMINISTRATION, DEPARTMENT OF ENERGY

Mr. Chairman and Members of the Committee: I appreciate the opportunity to appear before you today to discuss the history and status of U.S. refining capacity. The Energy Information Administration (EIA) is the independent statistical and analytical agency within the Department of Energy. We are charged with providing objective, timely, and relevant data, analysis, and projections for the Department of Energy, other government agencies, the U.S. Congress, and the public. We do not take positions on policy issues, but we do produce data and analysis reports that are meant to help policymakers determine energy policy. Because the Department of Energy Organization Act gives EIA an element of independence with respect to the analyses that we publish, our views are strictly those of EIA. They should not be construed as representing those of the Department of Energy or the Administration.

Recent high prices for crude oil and petroleum products, including gasoline, have raised increased attention to domestic refining capacity. Refining capacity utilization has risen to typical high summer levels, averaging about 96 percent for the past 4 weeks as gasoline demand has been increasing seasonally. West Texas Intermediate crude oil prices have fluctuated mainly between $36 and $42 per barrel since early March, and the national average retail price of regular gasoline prices reached $2.06 per gallon in late May before declining to $1.92 on July 12. Our current *Short Term Energy Outlook* (STEO) projects crude oil and product prices to remain high relative to recent years over the remainder of the summer. Crude prices are expected to average about $37 per barrel and gasoline prices may average about $1.83 per gallon over the second half of the year. Looking ahead to 2005, both international and domestic petroleum markets are projected to remain relatively tight, with low inventories and relatively high prices.

While refining capacity is an exacerbating factor in this Outlook, it is not the primary cause of these high prices. A combination of rising world oil demand growth and oil supply restraint by the Organization of Petroleum Exporting Countries (OPEC) has kept oil supplies tight, as reflected in low petroleum inventories worldwide since early last year. Even if more refining capacity were available, petroleum product prices would be high. But this lack of extra refining capacity means it will take longer for the market to ultimately rebalance when more crude oil supply arrives, and the potential for price volatility increases with little extra product inventory or refinery capacity that can act as a cushion in response to unexpected supply problems.

Today we consume about 20 million barrels per day of petroleum, of which about 84 percent comes from 149 domestic refineries, 9 percent comes from natural gas (e.g., propane and butane), 2 percent from ethanol and other oxygenates, and 5 percent from imports (Figure 1). About 70 percent of the net product imports are finished gasoline or gasoline blending components, of which almost two thirds came from Western Europe (29 percent), Canada (21 percent), and Virgin Islands (14 percent).

Concern regarding the adequacy of refining capacity is relatively recent. There was significant surplus capacity from the 1970's until the mid 1990s. Since the mid-1990s, both U.S. capacity and product imports have increased to keep up with growing demand for petroleum products. From 1997 through 2003, demand grew by 1.4 million barrels per day. During this same period, refiners expanded capacity at existing facilities by 1.2 million barrels per day,[1] which is equivalent to adding one medium-sized refinery per year, and net product imports grew by 0.5 million barrels per day, with total gasoline imports accounting for more than two-thirds of that product import growth.

As we look ahead over the next 10 to 20 years, total petroleum product demand is expected to increase about 1.6 percent per year, assuming current policies, with transportation fuels accounting for most of that growth, as projected in EIA's *Annual Energy Outlook.* EIA is projecting increases in refinery capacity and product imports will be needed to meet the continuing demand increases. Refinery capacity growth for the next 10 years will likely be the result of expansions at existing refineries, which have been more economical than building new refineries.

The breakdown between additional domestic refining capacity and increased product imports to meet projected demand growth in our forecast is highly uncertain. Our country's concerns over environmental quality can be expected to increase the cost, complexity, and time required for any expansion. In some cases, hurdles such as land constraints or public concerns may prevent expansions. At the same time,

[1] Capacity represents the change in average capacity available in 1997 compared to the average available in 2003. It does not include the moist recent additions to capacity.

growing world demand is expected to continue to increase competition for product imports, and U.S. product specifications may result in a reduction in available suppliers to the United States. U.S. gasoline and diesel specifications are currently more stringent than those in most other countries, which are moving towards cleaner fuels more slowly. As a result, some foreign refiners that previously supplied the United States may not be able to produce U.S.-quality gasoline until their own countries' specifications shift.

Absent policy changes (or other factors such as a sudden change in economic growth or weather) that unexpectedly reduce demand, EIA expects refineries will continue to run at relatively high utilizations during peak demand times, with little production cushion to respond to unexpected supply/demand imbalances. Under these circumstances, when markets are tight, as is the case this year, refinery outages can create temporary regional shortfalls that result in price spikes.

BACKGROUND

Refineries take crude oil and process it into many different petroleum products, from gasoline and diesel fuel to petrochemical feedstocks that are used to produce plastics and many other products. Crude oil is first separated into different components by heating the oil in the refinery primary distillation unit and collecting materials or fractions that evaporate within different boiling point ranges (Figure 2). For example, at this stage, some material in the gasoline boiling range is produced, but the yield of this gasoline volume may be small, representing only a fraction of the final gasoline produced.

Refiners then take the various streams from the distillation tower and process them further to make more gasoline, diesel, and other higher-value products. Different types and sizes of process units are needed for different crude oils. In general, more investment is needed to be able to process heavy, high-sulfur crude oils than light, low-sulfur crude oils. The processing downstream from the distillation tower involves splitting molecules (cracking processes) and re-combining or restructuring molecules (e.g., alkylation, reforming), as well as treating processes to remove sulfur and other materials that would add to air pollution when burned.

Finally various streams from these downstream units and some material from outside the refinery are combined or blended to produce the final products. For example, gasoline includes the gasoline stream that came directly from the distillation tower, alkylate from the alkylation unit, reformate from the reformer, and a gasoline stream from the fluid catalytic cracking unit. Each of these components has different properties (e.g., octane), so blending involves different "recipes" for different kinds of gasoline. The U.S. refinery system today can produce about 50 percent gasoline from a barrel of crude oil. This is called the gasoline yield.

The United States has 149 refineries totaling 16.9 million barrels of refinery distillation capacity, 72 percent of which is located in several major refining centers: The Gulf Coast (40 percent); Philadelphia and New Jersey (9 percent), Chicago and lower Illinois (8 percent), Los Angeles, San Francisco and Western Washington (15 percent). The remaining 28 percent of capacity is spread throughout the country, including Hawaii and Alaska.

The petroleum transportation system evolved to move product from major refinery centers to the rest of the country. The Gulf Coast, which is the largest refinery center in the world, moves product both into the Midwest and to the East Coast, mainly by pipeline. The Midwest, for example, receives about 27 percent of its gasoline from the Gulf Coast, and the East Coast receives about 50 percent. It takes about 20 days to move product from the Gulf Coast to the upper Midwest or Northeast. The East Coast also is highly dependent on gasoline imports. It receives most of the nation's gasoline imports, which serve about 25 percent of that region's demand. The West Coast is largely self-sufficient.

The pipeline and storage systems were originally designed to distribute a much smaller number of products than the number being handled today. The Clean Air Act Amendments of 1990 resulted in changes in product specifications requiring cleaner-burning fuels and also increased the number of fuel types being used in different parts of the country. Different types of gasoline evolved to meet both Federal and State clean air requirements. Areas with the worst smog problems were required to use the very clean Federal reformulated gasoline. In other areas, States could require cleaner fuels as part of their implementation plans to meet national air quality standards. Often, such requirements were tailored to meet local needs, resulting in a fuel that was cleaner and more expensive than conventional gasoline, but cheaper than Federal reformulated gasoline. But these different fuels had the effect of balkanizing the gasoline market, creating islands of different gasoline fuel

types. As more distinct fuels were developed, the existing delivery and storage system became more strained.

This balkanization has affected the petroleum system's ability to respond quickly to unexpected problems. An area using a distinct fuel cannot turn to nearby surrounding areas for supply if an unexpected problem develops. If a specialized type of gasoline, such as that required in the Chicago-Milwaukee region, runs short because an area refinery has an unplanned outage, extra product may not be stored nearby, and other area refineries may not be able to boost production to help resupply the market quickly. The region may have to wait until new supply arrives from a great distance, thus, contributing to the potential for price spikes when unexpected supply/demand imbalances occur.

The major price impacts associated with these distinct fuels have been in California and the Chicago-Milwaukee region, whose specialized fuels are harder to produce than other gasoline types. This results in fewer alternative suppliers to help meet any unexpected needs in these areas. In most other areas, price problems stemming from fuel distinctions have been relatively minor to date, but that could change if the market becomes further fragmented in the future.

There is no easy supply solution. Reducing the number of fuels from our current slate may ease the distribution and storage strain on the system, but such changes may shift the problem back to production. Reducing the number of fuels generally means producing more clean fuels, which are harder and more expensive to produce. This could create supply problems at refineries (e.g., lower gasoline yields, more closures, more investment), while easing problems in distribution. It is possible that expanding pipeline and storage infrastructure to better handle the increased fuel types might ease the problem more effectively than reducing the number of fuels.

HISTORICAL PERSPECTIVE ON CAPACITY

Concern regarding the adequacy of refining capacity is relatively recent (Figure 3). There was significant surplus capacity from the mid-1970's until the mid-1990s. The U.S. refining industry reached its peak in 1981 with 324 operating refineries with a total distillation capacity of 18.6 million barrels per calendar day. That same year, excess or surplus refining capacity, measured as operable capacity minus gross inputs, totaled about 5.9 million barrels per day, resulting in an average utilization rate of 69 percent. The excess had occurred as demand fell (particularly for residual fuel oil) following the large crude oil price increases in 1979-80.

Many small, inefficient refineries shut down in the early 1980s when the Domestic Crude Oil Allocation Program was removed and their subsidies ended, but capacity was still in excess relative to demand. Many small refineries have continued to close, albeit at a slower rate than in the early 1980s, to reach 149 refineries today. The last new grassroots refinery was completed in 1976. Even with the shutdowns, however, total capacity remained relatively flat since the mid-1980s as operating refineries expanded at exiting facilities.

Meanwhile, demand grew, filling the excess capacity that remained. In 1994, U.S. refinery capacity was 15.0 million barrels per day, its lowest point since the peak in 1981, and utilization had risen to 92.6 percent. Since the mid-1990s, both U.S. refining capacity and product imports have increased to keep up with growing demand. Utilization reached a peak in 1997 and 1998 during the summer months (May-August), averaging 98 and 99 percent, respectively, driven by gasoline demand. Increases in supply relaxed that very tight situation somewhat in the intervening years, with summer utilization varying between 93 and 96 percent. The added supply from 1997 through 2003 came from refiners expanding capacity at existing refineries by 1.2 million barrels per day and from net product imports by growing 0.5 million barrels per day, with total gasoline net imports accounting for more than two thirds of that product import growth (Figure 4). During this same time period, product demand grew by 1.4 million barrels per day—slightly less than supply.

This year may see U.S. refiners pushing towards those 1997-98 high utilization levels again. Gasoline demand growth has averaged 2.2 percent in the first half of the year compared to first half of 2003, while imports have been slightly lower than last year. Imports have been more difficult to attract due both to increasing international competition for volumes and fewer sources of gasoline supply able to produce U.S.-quality gasoline as a result of changing U.S. product specifications.

FUTURE CAPACITY NEEDS

As we look ahead, EIA projects total petroleum demand to grow on average 1.6 percent per year, assuming no changes in current policies. This means that over the next 10 years (through 2013), the United States will need an additional 20 percent

or 4 million barrels per day of total petroleum product supply. The largest part of this growth is in the transportation sector, which will require an additional 3.5 million barrels per day of product, mainly gasoline and diesel fuel. EIA projects that the United States will see both increases in refinery capacity and product imports to meet that continuing demand growth over this period. Net product imports are projected to continue to supply about 5 percent of demand,[2] resulting in an increase of about 0.5 million barrels per day over the next 10 years. This implies that some foreign refiners may be able to meet U.S. specifications more cheaply than U.S. refiners in the future. U.S. refining capacity would have to increase between 3 and 4 million barrels per day to serve the remaining demand growth.

While our forecast presents one scenario, the future availability of increased product imports to meet our growing demand is highly uncertain. For example, gasoline imports have been a very competitive supply source historically. A major source of these imports is Europe, which has been increasing use of diesel fuel in its light-duty vehicles, resulting in its refinery system producing more gasoline than European consumers require. The United States has been able to buy European gasoline more economically than expanding domestic refineries, so the relationship has benefited both regions. As we look to the future, some shifts in world markets are occurring.

First, world demand is growing and there is more competition for petroleum products available for sale internationally. The increasing competition for these products tends to increase their price, making them less attractive.

Second, the United States has stricter environmental gasoline specifications today than in many parts of the world. Although the rest of the world is also moving towards cleaner fuels, the number of suppliers that can produce U.S.-quality gasoline today has diminished. Our need for higher-valued gasoline and the reduced number of suppliers tends to increase the price we pay for imported gasoline. Both increased demand and change in product specifications have resulted in lower gasoline imports so far this year than last year. But how long will this imbalance last? Higher-priced alternative import supplies will tend to make domestic refinery expansion look more attractive than if imports were available at a lower price. But as other countries move to stricter product specifications and their refineries adjust, we could see a larger share of U.S. future demand being met by imports.

Additional domestic refinery capacity is needed not only to meet growing demand but also to counter some reduction in ability of refiners to produce gasoline from a barrel of crude oil as a result of changing product specifications. For example, the ban on MTBE seems to have reduced California refiners' ability to produce reformulated gasoline for that State during the summer months by about 10 percent. These refiners may be able to partially compensate with other process improvements, but that seems to be occurring slowly. Since refineries in that part of the country run near full capacity, more products must be shipped into the State to meet demand. In general, the move towards cleaner-burning fuels also results in some loss of yield.

While supply will evolve to meet demand, what cannot be predicted well is how much will come from U.S. capacity versus imports.

FACTORS AFFECTING DECISIONS TO SHUT DOWN OR EXPAND

The following discussion highlights some of the factors that influence individual company's decisions to shut down facilities or expand. This discussion is illustrative rather than comprehensive in order to highlight the many different factors that affect capacity decision making.

Even though demand has caught up with capacity, we continue to see refineries close, and we expect closures to continue. Most refineries that have closed are small, having capacities of less than 70 thousand barrels per day. Smaller refineries are less efficient than larger refineries, and many factors enter into their decision to close rather than expand. In some cases, environmental requirements play an important role. All refiners today must make environmental investments to stay in business. These investments are large, and generally economies of scale mean higher costs per barrel for smaller refineries. Small, less-efficient refiners facing these investments must consider if they can compete and earn an adequate return on that investment. In many cases, the answer has been no.

On net, refinery expansions have exceeded loss of capacity from shutdowns in the last 10 years. These expansions occurred at existing facilities and, on average, represented the equivalent of adding one medium-sized refinery per year. EIA's most recent capacity data for January 2004 indicate capacity increased over 2003 by

[2] Excludes unfinished oil imports, which are further processed in refinery units, and thus are not considered "product" imports for this paper.

137,000 barrels per day, the equivalent of yet one more medium sized refinery. Yet demand growth has required even more product imports.

Each company must consider whether or not a capacity investment will realize a reasonable return in the future. For much of the 1990s, returns on refining investments were small. Those returns have improved since 2000, but not smoothly or predictably. Price spikes during the spring and late summer for gasoline, and winter distillate price spikes in the past several years, contributed to improved returns, but in 2002, when international markets loosened, U.S. refining margins were low in spite of U.S. refineries running at high utilization rates. Yet, during tight markets, high utilization can exacerbate price volatility since refiners have little or no extra production capacity to respond to unexpected needs. Will margin increases seen since 2000 continue in the future long enough to merit increased capacity investments? Each company must weigh its decision based on market fundamentals and its own unique situation.

The way in which companies have expanded capacity over the last 20 years indicates it has been more economical on a dollar-per-barrel basis to expand at an existing facility than to build a grassroots refinery. Siting approvals are also generally easier at an existing location. Between 1990 and 2003, 14 medium and large refineries increased capacity by more than 50 percent. Those refineries alone added more than 1million barrels per day of capacity during that time. The economics of expansion in either case are affected by varying regulatory hurdles and public acceptance. The higher these hurdles are, the higher the margins required to justify expansion.

Dollars available for expansion may also influence decisions. Right now, the industry is investing billions of dollars to remove sulfur from both gasoline and diesel fuel. While these investments will create much cleaner-burning fuels, they also may detract from expansion for a short time.

Companies will view the factors affecting future expansion differently. Their differing views on future margins, on their ability to compete with other domestic refiners or importers, on market growth and so forth will lead one company to expand and another to shut down a facility. But ultimately, we expect to see some refinery expansion continue in the future.

Thank you for the opportunity to testify before the committee today.

Figure 1

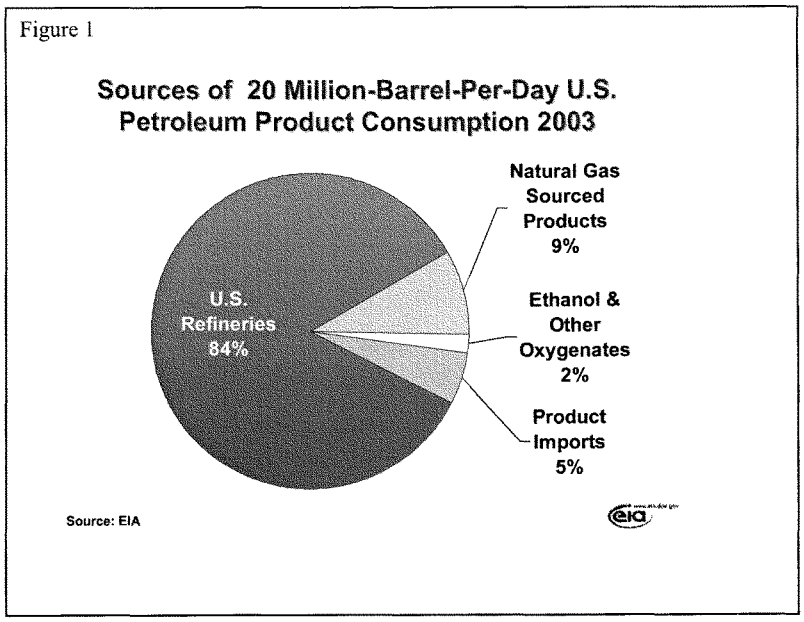


Figure 2

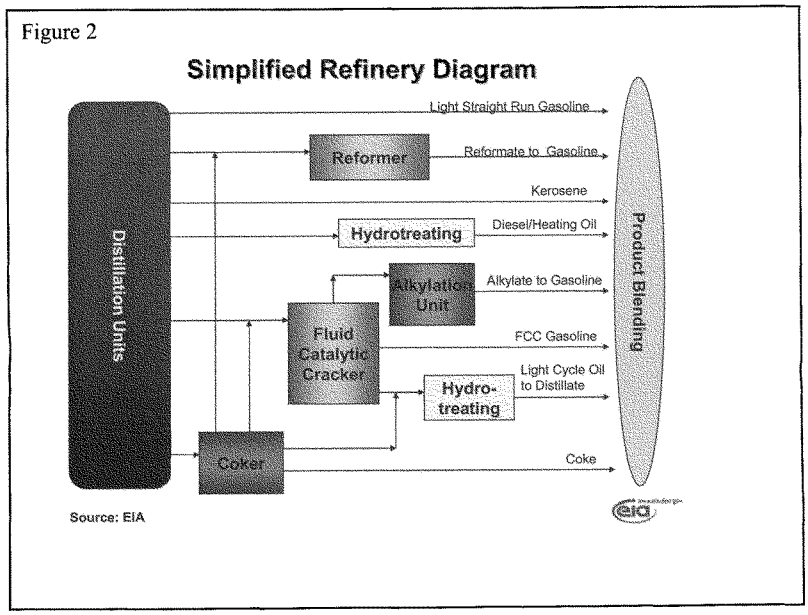


Figure 3

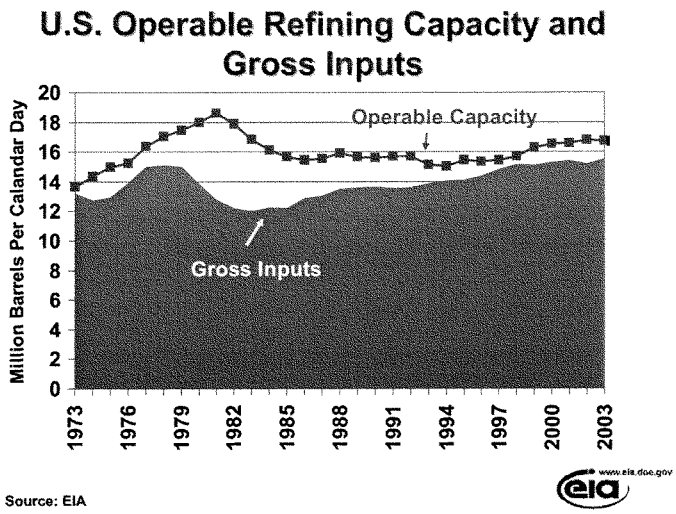
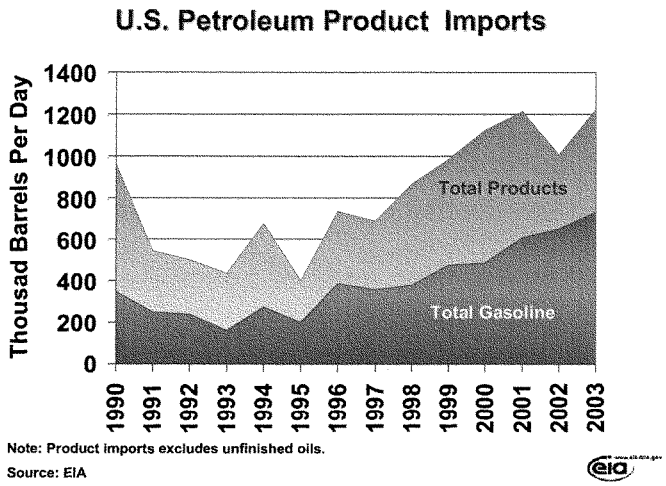


Figure 4



Mr. HALL. Thank you, and we will have questions.

Mr. Holmstead.

STATEMENT OF HON. JEFFREY R. HOLMSTEAD

Mr. HOLMSTEAD. Thank you, Mr. Chairman and members of your subcommittee, for the invitation to appear here today.

EPA began to regulate motor fuel back in the 1970's, when the Agency first required that lead be phased out of gasoline, but the focus of attention in recent years has been on two clean fuel programs that came directly from the 1990 Amendments to the Clean Air Act. One is known as the Reformulated Gasoline program, or RFG. The other one is the Tier 2 low sulfur gasoline program, and let me just briefly mention each of those.

By statute, every gallon of RFG, of reformulated gasoline, is required to contain a minimum amount of oxygenates, such as ethanol or MTBE. EPA and the Department of Energy have estimated that the cost of producing RFG is about 4 to 8 cents per gallon greater than the cost of producing conventional gasoline, and about half of this cost increment is due to the cost of the oxygen requirement itself. Now, I should note that the average retail price, the price that we actually pay at the pump, the price of RFG today is, on average, about 4 cents per gallon greater than the cost of conventional gasoline.

The second clean fuel program I mentioned, the Tier 2 program, began on January 1 of this year. By 2006, this program will reduce the sulfur content of most gasoline sold in the U.S. by about 90 percent. This reduction in the sulfur content immediately reduces emissions from all gasoline-powered vehicles, but it also enables the use of advanced technologies to control pollution. So, the Tier 2 program also includes a phase-in that begins this year of much more stringent tailpipe standards, so we are regulating both the fuel and the vehicles. We estimate that the Tier 2 will cost about a penny a gallon today, and when it is fully phased in in 2006, that cost will be about 2 cents a gallon, two pennies.

The important thing, the way we look at these programs, is to compare the cost of the program with its benefits. On the benefit side, we estimate that the Tier 2 program including both the fuel and engine standards will prevent every year approximately 4,000 premature deaths, approximately 10,000 cases of chronic and acute bronchitis, and tens of thousands of respiratory problems a year. And on this program, as far as I know, everyone agrees that the public health benefits of the program far exceed its cost.

As you have heard this afternoon already, this morning and this afternoon, the retail price of gasoline is affected by many factors. We believe that the run-up in gasoline prices earlier this year was primarily the result of a steep increase in crude oil prices, and we can say with great confidence that the clean fuel regulations have had only a minimal impact on gasoline prices.

Let me turn now very quickly to the issue of so-called "boutique fuels." The Clean Air Act specifically authorizes States to regulate fuel as part of their State air quality plans if they need this type of regulation to achieve a national air quality standard. This has resulted in a number of different fuel formulations being required by different States. These formulations are often referred to as

"boutique fuels," and 15 States have adopted their own clean fuel programs for part or all of the State.

In October 2001, EPA released a comprehensive White Paper discussing the range of issues associated with the boutique fuel programs, and the three basic conclusions of this paper were: (1) that the current gasoline refining and distribution system works quite well except during times of unexpected disruption, which you have alluded; (2) that fewer fuel types would improve the fungibility of the gasoline pool; and (3) options exist to reduce the number of fuel types and to improve fungibility while maintaining or improving air quality, but the fungibility benefits from taking these actions are likely to be modest, and there may be a significant cost or supply implications associated with these options.

Now, we are committed to working with Congress to explore ways to maintain or enhance the environmental benefits of clean fuel programs while exploring ways to increase the flexibility of the fuel distribution infrastructure and provide added gasoline markup liquidity. And I will say that the best way that we have identified to accomplish these goals is to replace the current oxygen requirement for RFG with a renewable fuel standard that includes a flexible nationwide credit trading system, but this can only be done through legislation such as the renewable fuels provisions in the Energy Bill which the Administration strongly supports.

Mr. Chairman, members of the subcommittee, we at EPA have learned a great deal about cleaner burning fuels and boutique fuels programs since 1990, and we would be pleased to work with Congress and with this subcommittee to look for ways to make improvements.

This concludes my prepared statement and, again, at the appropriate time, I would be happy to answer questions.

[The prepared statement of Hon. Jeffrey R. Holmstead follows:]

PREPARED STATEMENT OF JEFFREY HOLMSTEAD, OFFICE OF AIR AND RADIATION, U.S. ENVIRONMENTAL PROTECTION AGENCY

Thank you, Mr. Chairman and Members of the Subcommittee, for the invitation to appear here today. I appreciate the opportunity to discuss the vital role cleaner burning gasoline plays in improving America's air quality and to comment on the subject of gasoline prices and "boutique fuels." I also will explain the status of the Environmental Protection Agency's review of California's and New York's requests for a waiver of the oxygen content requirement in reformulated gasoline used in those States.

BACKGROUND OF CLEANER BURNING GASOLINE

Mr. Chairman, as you know, EPA began to improve the quality of motor vehicle fuel in the 1970's when unleaded gas was first introduced. Today, I would like to focus my comments on two clean fuel programs that are a direct result of the Clean Air Act Amendments of 1990: reformulated gasoline (RFG) and Tier 2 low sulfur gasoline. The purpose of both programs is to improve public health by reducing harmful exhaust from the tailpipes of motor vehicles. The RFG program began in 1995 and was designed to serve several goals. These include: (1) improving air quality by reducing ozone precursor pollutants; (2) reducing emissions of specific toxic pollutants such as benzene; and (3) extending the gasoline supply through the use of oxygenates. Every gallon of RFG is required to contain a minimum amount of an oxygenate, such as ethanol or MTBE. EPA and the Department of Energy have estimated the cost of producing RFG to be approximately 4 to 8 cents per gallon greater than conventional gasoline. Of this amount, approximately half of this cost increment is due to the cost of the oxygen requirement itself. I should note that the average retail price of RFG today is only about 4 cents per gallon greater than conventional gasoline.

New regulations to control pollution under the Tier 2 Vehicle and Gasoline Sulfur Program began this year. This program, established in 1999, is the result of a collaborative effort involving a wide range of stakeholders. EPA worked closely with auto companies, oil companies, states, public health and environmental organizations, and others to design a stringent, but balanced program that all key stakeholders could support. The sulfur content of gasoline is being phased down nationwide over several years with a 120 parts per million (ppm) limit this year, a 90 ppm limit in 2005, and a final 30 ppm average limit set to take effect in 2006. Ultimately, these new standards will reduce the sulfur content of gasoline by up to 90 percent. As sulfur is being reduced from gasoline, tight tailpipe emissions standards are also being phased in for new passenger vehicles.

EPA estimates this Tier 2 program will prevent as many as 4,300 deaths, more than 10,000 cases of chronic and acute bronchitis, and tens of thousands of respiratory problems a year. The public health and environmental benefits of this program (more than $25 billion) far exceed the costs to consumers. EPA estimates that the Tier 2 program only increases costs to consumers by about 1 cent per gallon today, and will still cost less than 2 cents per gallon when the program is fully phased in, in 2006.

We have been monitoring very closely the transition to the low sulfur gasoline program, and believe that it has been—and will continue to be—a smooth one. This success is largely attributed to the fact that the Tier 2 program incorporates a number of flexibilities to ease the economic burden on the oil industry. These include:

- A market-based trading system, which allows companies to reduce costs by averaging, banking and trading sulfur levels among different refineries, between companies, and across time.
- A geographic phase-in program, which provides a slightly higher interim sulfur standard for gasoline sold in parts of the Western U.S. This program recognizes that this area is dominated by small capacity, geographically-isolated refineries that would have a more difficult time competing for engineering and construction resources to modify their refineries to meet the standards.
- A small refiner program, which gives small refiners more time to meet the standards, recognizing their financial challenges in raising capital for the desulfurization investments; and
- A hardship provision, which allows refineries to apply on a case-by-case basis for additional time and flexibility to meet the low sulfur standards, based on a showing of unique circumstances. Under this program, thus far EPA has granted hardship waivers to six refineries.

COST OF GASOLINE

The retail price of gasoline is affected by many factors, and my colleague from EIA will provide further information on this subject. However, I would like to mention several key points:

- Worldwide crude oil prices are at their highest level since 1990 with West Texas Intermediate (WTI) oil prices reaching a 13-year peak of $42.33 per barrel on June 1, 2004.
- Fuel demand continues to increase as Americans travel more. Over the past twenty years vehicle miles traveled (VMT) has increased five times faster than U.S. population.
- Since 1997, fleet-wide fuel economy has been relatively constant, ranging from 20.6 to 20.9 miles per gallon (mpg). Fleet-average fuel economy peaked in 1987 at 22.1 mpg, but has declined since then due to the increasing popularity of less fuel-efficient light trucks, particularly SUVs.
- The number of refineries in the U.S. has been declining steadily, while the capacity of the remaining refineries has been increasing. In 1990, the number of refineries in the U.S. was 205 with a capacity of 15.5 million barrels per day. In 2002, the number of refineries decreased to 153; with a capacity of 16.8 million barrels per day. As a result, the share of imported gasoline has nearly tripled over the last two decades.

Crude oil costs are the single largest component of gasoline prices, and account for nearly half of the cost of gasoline. Exhibit 1 shows that gasoline price fluctuations track very closely with crude oil prices. The chart shows the price of RFG since 2000 to the present, as well as the price of crude oil in that same time period. The price increase was essentially the same for both RFG and conventional gasoline.

With the exception of several instances of serious disruptions in the production and distribution system, such as pipeline breaks and refinery fires, fuel suppliers have provided a sufficient supply of gasoline to motorists. The run-up in gasoline prices earlier this year was primarily the result of a steep increase in crude oil

prices. We believe that environmental regulations have had a minimal effect on gasoline prices. As I discuss below, additional state and local clean fuel requirements may pose challenges to fuel suppliers during times of market disruption.

Exhibit 2 tracks gasoline prices and crude oil prices from October 2003 to the present. Like the long term trend shown in Exhibit 1, this chart also indicates that the price of RFG tracks closely with the price of crude oil. The chart indicates the percentage of the cost of crude oil to the price of RFG at the pump for the time period of October 2003 to the present. The percentage is relatively constant, even during the period during which the Tier 2 low sulfur gasoline was being phased in, and during the transition from winter to summertime RFG. Thus, it is apparent that crude oil prices play a large role in the price at the pump.

REFINERY PERMITTING

Recently, some representatives of the refining industry have stated that the permitting process in the U.S. is a major barrier and source of uncertainty to both building new refineries and expanding the capacity of existing ones. I would like to address this very important issue.

The term "permitting" encompasses many different regulations, activities, and governmental agencies. One of the programs that affect permitting decisions is the New Source Review or NSR regulations. Congress established this program with the goal of ensuring that new sources (and existing sources that make major modifications that increase emissions) install good air pollution controls. Pursuant to the Clean Air Act, EPA has set minimum requirements for NSR programs. States then have the option of implementing EPA's program or running their own programs, which can be more stringent than the federal program. There are also state and local requirements, such as conditional use permits, that involve land use and other issues. For these state and local permits, over which EPA has no control, stakeholders such as local citizen groups may get involved and challenge the refiner's proposed action.

In response to the President's National Energy Policy (May 2001), EPA conducted a review of the NSR process and its effect on potential new refineries and on expansion of capacity at existing refineries. In a Report to the President (June 2001), we concluded that NSR had not significantly impeded investment in new refineries. We did find, however, that NSR discouraged projects for the refining and other industries that would have provided additional capacity or efficiency improvements and would not have increased air pollution. In response to these findings, EPA recently revised its NSR regulations to remove barriers to beneficial projects that would provide the additional capacity or achieve efficiency improvements with no increased air pollution, and to provide greater regulatory certainty for industry. We expect these reforms to streamline the NSR process for refineries and provide flexibility for sources to continue to meet our energy needs in an environmentally protective fashion for years to come. We are working with States to get these reforms approved and implemented as expeditiously as possible.

There are circumstances that may require special attention to the permit process so that critical facilities can be built or expanded, while still meeting environmental regulations. When presented with these circumstances, EPA and the states have demonstrated a willingness to ensure that appropriate permits move expeditiously. For example, although the refining industry was very concerned during the development of the Tier 2 low-sulfur gasoline rules that NSR permitting would make it difficult to make the facility changes necessary to meet the new rules, we have not found that to be the case. In response to the industry's concerns, EPA committed to work closely with the state and regional organizations responsible for processing permit applications to help expedite the process to the extent possible. As part of this effort, we prepared guidance for conducting Best Available Control Technology (BACT) analyses, as required under the Prevention of Significant Deterioration permit program, and provided resources to expedite the processing of permit applications. We offer the same degree of cooperation with agencies and refiners in helping to streamline the permitting process to the greatest extent possible under the existing regulatory structure.

STATE AND LOCAL CLEAN FUEL PROGRAMS

Let me turn now to the issue of the so-called "boutique fuels." The variation in fuels due to state and local fuel requirements is occasionally pointed to as contributing to higher gasoline prices, and some have inquired why EPA has approved the use of such fuels. The Clean Air Act authorizes states to regulate fuels as part of their state implementation plans—or SIPs—if EPA finds such regulations necessary to achieve a national air quality standard. This has resulted in a number of dif-

ferent formulations being required by states, which are often referred to as boutique fuels. Fifteen states have adopted their own clean fuel programs for part or all of the state. In those states that require gasoline that differs from federal standards, such gasoline generally has lower volatility than gasoline under the federal standards. In some cases, a state has adopted such a fuel program because it wanted the benefits of cleaner burning gasoline, but without the requirement that it contain an oxygenate.

Before adopting these boutique fuel controls, states often engage in a public advisory process to consult with stakeholders, including refiners and fuel suppliers that serve the affected region, and other members of the public. Refiners typically have worked with states to design fuel controls that meet the region's air quality needs at the lowest possible cost. Therefore, the process of adopting fuel programs that contain different requirements than federal regulations is typically a joint effort between the refiners and suppliers, the public, and the state environmental agencies. Fuel supply and cost are important considerations when designing the program. Therefore, we advise states that are considering adopting their own clean fuel program to initiate this collaborative process.

The President's National Energy Policy issued in May, 2001 directed EPA to study opportunities, in consultation with DOE, USDA and other agencies, to maintain or improve the environmental benefits of state and local boutique fuel programs, while exploring ways to increase the flexibility of the fuels distribution system.

In October, 2001 EPA released an extensive EPA Staff White Paper on boutique fuels. The broad conclusions from this White Paper still hold up today: (1) the current gasoline refining and distribution system works well, except during times of disruption, (2) fewer fuel types are likely to improve fungibility, and (3) options exist to reduce the number of fuel types and improve fungibility while maintaining or improving air quality, although the fungibility benefits from taking these actions are likely to be modest and there may be significant cost or supply implications associated with these options.

EPA's authority to address many of these issues is limited. We are committed to working with Congress to explore ways to maintain or enhance the environmental benefits of clean fuel programs, while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity. The Administration supported energy bill provisions that would replace the statutory oxygen content requirement for RFG with a renewable fuel standard that includes a flexible, national credit-trading system.

REQUESTS FOR WAIVERS FROM THE OXYGEN REQUIREMENT IN RFG

I would now like to talk about the status of California's and New York's requests for a waiver of the oxygen requirement in RFG. The Clean Air Act requires that RFG be used in the highly polluted areas of the U.S. and that RFG contain a minimum of 2.0 percent by weight oxygen. In order to receive a waiver from the federal RFG oxygen requirement, a state must show that the requirement will interfere with the state's ability to attain a NAAQS.

Congress set a high hurdle for granting such waivers, and severely limits EPA's discretion. For example, the Clean Air Act does not allow the Agency to consider the risks of MTBE contamination of drinking water in California and New York. It also does not allow the Agency to consider the effect on gasoline prices or energy supplies that the oxygenate requirement and state bans on MTBE might have.

As was apparent in our denial of California's request in June of 2001, analyzing the emissions effects of granting a waiver is a very complicated endeavor. For example, the granting of a waiver would not result in the use of a uniform market of non-oxygenated RFG in the California RFG areas but, rather, some amount of oxygenated RFG would be used. Because California enacted a ban on the use of MTBE in gasoline, the oxygenate in California RFG is ethanol. A market which includes both non-oxygenated and ethanol oxygenated RFG creates the potential for mixing, called commingling, of the two types of fuel in the gas tanks of automobiles, which in turn results in increased emissions of volatile organic compounds. Other complicated issues arise such as how refiners would reformulate their gasoline without an oxygen requirement and still meet the emissions performance requirements of RFG. In combination, these issues and others determine whether the granting of a waiver would, in fact, help or hinder the air quality situation in the state. We continue to sort out these complex issues as we review the data and analyses submitted by the State in support of its waiver request. Our actions with respect to the waiver requests from California and New York are no different in this regard.

In short, the Clean Air Act provides significant constraints for granting waivers of the oxygen requirement in RFG. We believe that the difficulties that the oxygen

requirement poses for certain states can best be remedied by passage of comprehensive energy legislation that will simplify federal gasoline requirements by replacing the RFG oxygenate requirement with a national renewable fuels standard that includes a flexible credit trading system.

Mr. Chairman and members of the Subcommittee, the clean fuel programs I have talked about today are critical to our nation's efforts to reduce the harmful effects of air pollution from motor vehicles. They are also important to the production and distribution of gasoline at a fair price to consumers. We have learned a great deal about cleaner burning fuels since 1990 and the Agency will continue to look for ways to make improvements.

This concludes my prepared statement. I would be pleased to answer any questions that you may have.

Exhibit 1: Crude oil costs vs RFG prices (2000-2004)

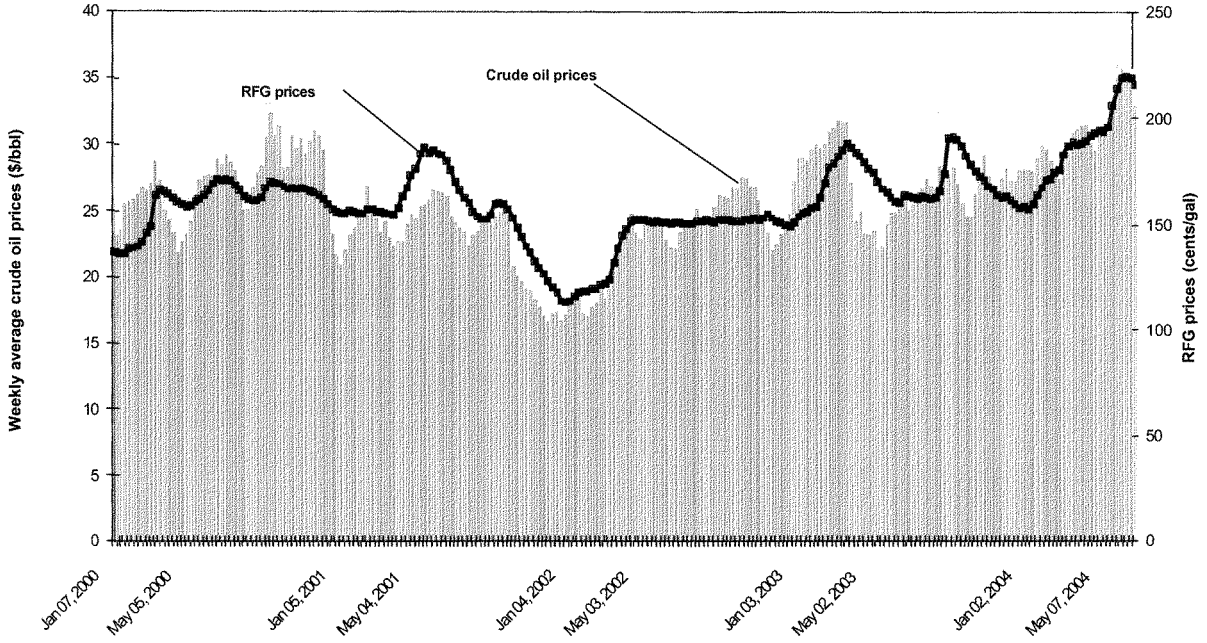
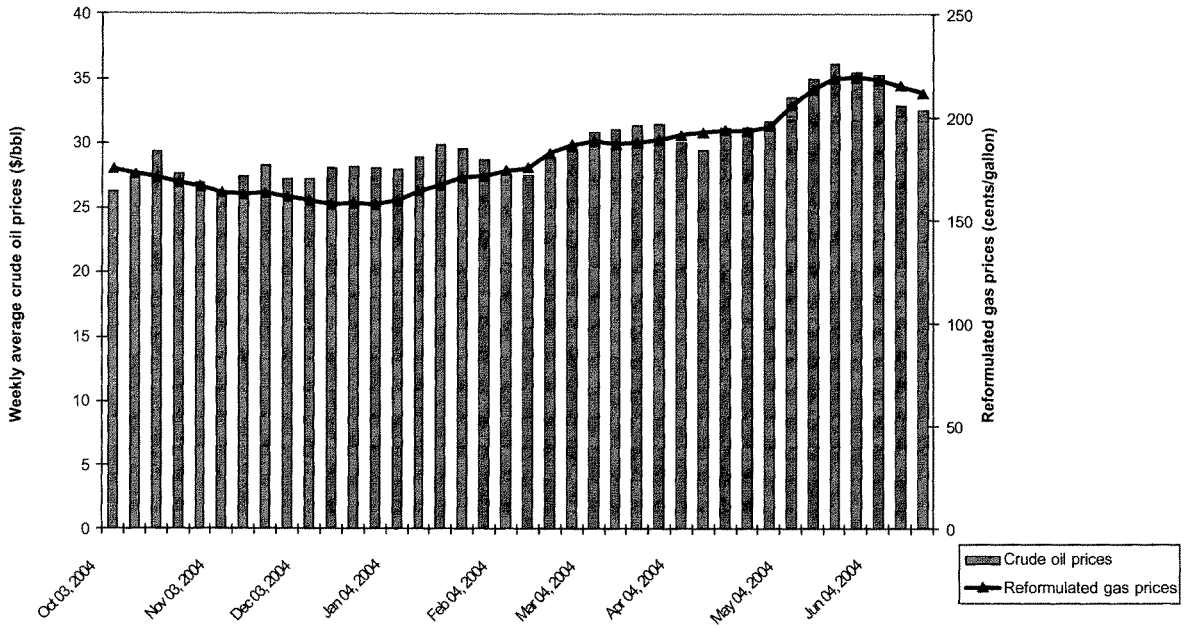


Exhibit 2: Crude oil costs vs RFG prices (Oct 03 – June 04)



Mr. HALL. Thank you very much.
Director Wells.

STATEMENT OF JIM WELLS

Mr. WELLS. Thank you, Mr. Chairman. We welcome the opportunity to contribute to your hearing today on issues relating to the U.S. refining industry. We all know that world crude oil prices and its availability are the principal price drivers. However, even if you have all the crude oil you need, our refining capacity can be a choke point.

Today, we have 149 refineries. Twenty-three years ago, we had 325. I might add that not all of today's refineries are actually producing gasoline. Statistics say that they are running at about 96 percent capacity in utilization. The challenges will clearly be to meet the growing demand, pick your number—10 million, 15 million, 20 million barrels a day—if something breaks or supply is disrupted, one of the first things that happens is price volatility.

In 2002, we agreed to do a study to look at a study of the effect of the wave of mergers that occurred in the mid to late 1990's. Twenty-six hundred mergers changed the landscape of how the sale of petroleum products occurred. Large oil companies combined with other large oil companies who previously competed with each other. For example, in 1998, BP and Amoco merged, and later acquired ARCO, while Exxon acquired Mobile. Since the mid 1990's, approximately 40 refiners have been involved in mergers. Did this wave of mergers reduce competition and generally lead to higher gasoline prices? Our study came to a conclusion that said "yes."

To our knowledge, we have produced the only study of this magnitude and scope to date. What analysis was in the literature and academia publications was on a smaller scale, and clearly not nationwide or dealing with the multitude and multiple factors involving multiple mergers.

We constructed econometric models to estimate the effects of these mergers on market concentration on prices at the wholesale because we believed that the bottlenecks in the gasoline markets are most commonly detected at the refining and distribution levels. Also, price changes at the wholesale levels generally get passed through at the pump in terms of prices.

What we did find and document was that the marketplace clearly had changed. There are fewer oil companies and refiners. There is less non-branded gasoline that was traditionally offered to the marketplace at lower prices. Distribution and availability of gasoline to the smaller dealers, the mom and pops, if you will, is on the decrease. Market concentration which relates to market shares and market activity increased at the refining levels across the board. On the one hand, it is clear that mergers potentially enable companies to gain synergy, grow assets, and reduce cost-achieving efficiencies that may be passed along to the consumers at the gas pump. Clearly, this is a good thing. However, if you get bigger and fewer competitors, you may also gain a situation involving market power, and that is the ability to raise prices above competitive levels. Taken collectively, our models, at least at the wholesale price levels, showed an increase of anywhere from 1 to 7 cents for six out

of the eight major mergers that we analyzed. Again, a retrospective look looking back at what happened after the mergers occurred.

Our findings imply that the overall effects of market power, which does tend to increase prices, won out over the efficiency gains that you would expect that could perhaps decrease prices.

In any study of this magnitude, you can expect to have many differences of opinion. The FTC, as you will hear this morning, will weigh in with their views. Although no econometric model can perfectly predict reality, we believe that our models and the facts and analyses that we did are methodologically sound and produce reasonable estimates, or at least starting points, for future discussions.

Mr. Chairman, in summary, we believe our retrospective look and study back at the wave of mergers that occurred in the 1990's will help you as you wrestle with the refining issues in this country, and we would hope that our study could influence what the regulatory antitrust agencies like the FTC do in the future to protect the competitive process and ultimately the consumers that have to buy gasoline at the pump.

Thank you, Mr. Chairman.

[The prepared statement of Jim Wells appears at the end of the hearing.]

Mr. HALL. Thank you. The Chair recognizes Mr. Kovacic.

STATEMENT OF WILLIAM E. KOVACIC

Mr. KOVACIC. Mr. Chairman and members of the subcommittee, I want to thank you for the opportunity to present the FTC's testimony concerning competition policy in the U.S. refining industry.

My written statement gives the Federal Trade Commission's views, and my spoken comments today are from my own views and not necessarily those of the Commission or its members.

Competition policy unmistakenly plays a key role in protecting consumers of refined petroleum products such as gasoline. Since the early 1980's, the FTC has been the Federal Agency mainly responsible for competition policy issues in the petroleum sector. No industry has commanded closer attention from this Agency.

The FTC promotes competition in refining in four ways. First, the Commission opposes mergers that promise to curb competition and demands divestitures and other relief to cure competitive problems. Second, the Agency prosecutes non-merger antitrust violations involving refiners. For example, the Agency is now litigating an administrative complaint against Unocal. This complaint alleges that Unocal manipulated California's regulatory process for establishing standards for reformulated gasoline. Third, the FTC uses a statistical model to detect unusual gasoline price movements nationwide and to spot possible antitrust violations. And, finally, the FTC performs research on key industry trends. Later this year, the Commission expects to publish separate reports on mergers and factors that affect gasoline prices.

Collectively, these activities have given the FTC unequalled competition policy expertise in this sector and unmatched knowledge, I believe, of the institutional arrangements that determine the form and intensity of rivalry in this sector. It is from this perspec-

tive that we have read and evaluated GAO's report on petroleum industry mergers and concentration.

I applaud the GAO's interest in evaluating merger outcomes. The evaluation of policy outcomes is a valuable ingredient of responsible public administration. To provide a suitable basis for informing policy, an evaluation must be analytically sound. And with respect to Jim Wells and my fellow Government colleagues at the GAO, the GAO report contains, we believe, fundamental methodological errors that deny its results reliability. Jim Wells is absolutely right: the study doesn't have to be perfect. But it has to be good enough to be reliable. You can be a few feet off, for example, in navigation in flying across the country from Washington to LAX. But be a few miles off, and you are in the Pacific Ocean. What we are really debating here is that degree of accuracy.

Three crucial flaws, in our view, stand out. First, GAO's econometric analyses did not properly account for many factors that we believe affected prices in the transactions they examined. Second, GAO's study of how concentration affects prices do not use properly defined relavant markets—to use some antitrust jargon—required for good analysis. And, last, we believe that GAO failed to consider critical facts about individual transactions, such as the ExxonMobil consolidation, that are vital to assess price effects.

We welcome rigorous analysis of antitrust policy. In this spirit, we have invited the GAO to join the FTC in co-hosting a public conference to consider the GAO report's findings and certainly indirectly, since it is our merger review that is at issue, our own work. To inform the proceedings, we call upon GAO to fully disclose its econometric methodology and the data it used to run its models. Participants at the conference would include our own colleagues as well as outside experts and advisors and other observers with a keen interest in this field.

We see the event, as Jim has just mentioned, as a possible step forward. We see it as a way to educate policymakers and other interested observers about the way in which the industry operates, the way in which merger review takes place, and the way in which different choices about competition policy are formulated. Indeed, we welcome an absolutely unflinching assessment of our work. We have confidence in our competition policy program and the analytical techniques on which it rests, but if rigorous public debate showed that this confidence was misplaced, we would have the humility and the dedication to good public policy to make adjustments.

I welcome your questions.

[The prepared statement of William E. Kovacic follows:]

PREPARED STATEMENT OF WILLIAM E. KOVACIC, GENERAL COUNSEL, FEDERAL TRADE COMMISSION

I. INTRODUCTION

Mr. Chairman and members of the Subcommittee, I am Bill Kovacic, General Counsel of the Federal Trade Commission. I am pleased to appear before you to

present the Commission's testimony on FTC initiatives to protect competitive markets in the production, distribution and sale of gasoline.[1]

The petroleum industry plays a crucial role in our economy. Not only do changes in gasoline prices affect consumers directly, but the price and availability of gasoline also influence many other economic sectors. No other industry's performance is more visibly or deeply felt.

The FTC's petroleum industry activities today reflect the sector's importance. The Commission fully exercises every tool at its disposal—including the prosecution of cases, the preparation of studies, and advocacy before other government bodies—to protect consumers from anticompetitive conduct and from unfair or deceptive acts or practices. In doing so, the FTC has built an unequaled base of competition and consumer protection experience and expertise in matters affecting the production and distribution of gasoline.

The Commission's testimony today addresses the Subcommittee's inquiries in two parts. It first reviews the basic tools that the Commission uses to promote competition in the petroleum industry: challenges to potentially anticompetitive mergers, prosecution of nonmerger antitrust violations, monitoring industry behavior to detect anticompetitive conduct, and research to understand petroleum sector developments. This segment of the testimony highlights what we believe to be some of the flaws of a recent Government Accountability Office ("GAO," formerly known as the "General Accounting Office") report analyzing the effects of various petroleum industry mergers completed from 1997 through 2000. The review of the Commission's petroleum industry agenda highlights how the FTC is contributing to efforts to maintain and promote competition in the industry.

The second part of this testimony reviews learning the Commission has derived from its review of recent gasoline price changes. Among other findings, this discussion highlights the paramount role that crude oil prices play in determining both the level and movement of gasoline prices in the United States. Changes in crude oil prices account for approximately 85 percent of the variability of gasoline prices.[2] When crude oil prices rise, so do gasoline prices. Crude oil prices are determined by supply and demand conditions worldwide, most notably by production levels set by members of the Organization of Petroleum Exporting Countries ("OPEC"). As Figure 1 illustrates, changes in gasoline prices historically have tracked changes in the price of crude oil.[3] With crude oil prices in the range of $40 per barrel, it is not surprising that we are seeing higher gasoline prices nationwide.[4]

As a whole, the Commission's testimony develops two themes. First, the Commission places a premium on careful research, industry monitoring, and investigations to understand current petroleum industry developments and to identify accurately obstacles to competition, whether arising from private behavior or from public policies. The petroleum industry's performance is shaped by the interaction of extraor-

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[1] This written statement represents the views of the Federal Trade Commission. My oral presentation and responses to questions are my own and do not necessarily represent the views of the Commission or any individual Commissioner.

[2] A simple regression of the monthly average national price of gasoline on the monthly average price of West Texas Intermediate crude oil shows that the variation in the price of crude oil explains approximately 85 percent of the variation in the price of gasoline. Data for the period January 1984 to October 2003 were used. This is similar to the range of effects given in United States Department of Energy/Energy Information Administration, *Price Changes in the Gasoline Market: Are Midwestern Gasoline Prices Downward Sticky?,* DOE/EIA-0626 (Feb. 1999). More complex regression analysis and more disaggregated data may give somewhat different estimates, but the latter estimates are likely to be of the same general magnitude.

This percentage may vary across states or regions. See Prepared Statement of Justine Hastings before the Committee on the Judiciary, Subcommittee on Antitrust, Competition Policy and Consumer Rights, U.S. Senate, *Crude Oil: The Source of Higher Gas Prices* (Apr. 7, 2004). Dr. Hastings found a range of approximately 70 percent for California and 91 percent for South Carolina. South Carolina uses only conventional gasoline and is supplied largely by major product pipelines that pass through the state on their way north from the large refinery centers on the Gulf. California, with its unique fuel specifications and its relative isolation from refinery centers in other parts of the United States, historically has been more susceptible to supply disruptions that can cause major gasoline price changes, independent of crude oil price changes.

[3] Figure 1 (covering the period 1949 through 2002) also illustrates that the real price of gasoline has fallen dramatically since its historic high in the early 1980s. The difference between the price of crude oil (per gallon of gasoline) and the price of a gallon of gasoline has remained fairly constant for the same time period, generally around $.80 per gallon. (All figures are in 2002 dollars.) This is dramatically lower than the difference for the years preceding 1980.

[4] Crude oil prices have fallen from a high of approximately $42 per barrel (May 24 and June 1) to approximately $38 per barrel (July 2); this is a drop of approximately 9.5 cents per gallon. The price of gasoline has dropped from a national average of $2.05 per gallon (May 27) to $1.91 per gallon (July 2). See Energy Information Administration ("EIA"), *Weekly Petroleum Status Report;* national average retail price of gasoline obtained from Oil Price Information Service.

dinarily complex, fast-changing commercial arrangements and an elaborate set of public regulatory commands. A well-informed understanding of these factors is essential if FTC actions are to benefit consumers.

Second, the Commission is, and will continue to be, vigilant in challenging anticompetitive mergers and nonmerger antitrust violations in the petroleum industry and in urging other government bodies to adopt procompetitive policies for this sector. We will not hesitate to suggest to Congress how the existing framework of laws might be improved to facilitate Commission intervention that will improve consumer well-being. This testimony, at Section III, identifies various laws and regulations that increase the cost of producing gasoline and the price of gasoline.

II. FTC ACTIVITIES TO MAINTAIN AND PROMOTE COMPETITION IN THE PETROLEUM INDUSTRY

A. Merger Enforcement in the Petroleum Industry

The Commission has gained much of its antitrust enforcement experience in the petroleum industry by analyzing proposed mergers and challenging transactions that likely would reduce competition, result in higher prices, or otherwise injure the economy.[5] Since 1981, the Commission has taken enforcement action against 15 major petroleum mergers.[6] Four of the mergers were either abandoned or blocked as a result of Commission or court action. In the other 11 cases, the Commission required the merging companies to divest substantial assets in the markets where competitive harm was likely to occur.[7]

In all 15 cases, the agency sought to maintain the pre-merger levels of concentration in the relevant markets in which there was found to be a sufficient likelihood that the merger would have an anticompetitive effect. The Commission recently released data on all horizontal merger investigations and enforcement actions from 1996 to 2003. These data show that the Commission has brought more merger cases at lower levels of concentration in the petroleum industry than in other industries. Unlike in other industries, the Commission has obtained merger relief in moderately concentrated petroleum markets.[8]

1. Recent FTC Merger Investigations—Three recent merger investigations illustrate the FTC's approach to merger analysis in the petroleum industry. The first is the merger of Chevron and Texaco,[9] which combined assets located throughout the United States. Following an investigation in which 12 states participated, the Commission issued a consent order against the merging parties requiring numerous divestitures to maintain competition in particular relevant markets, primarily in the western and southern United States. Among other requirements, the consent order compelled Texaco to: (a) divest to Shell and/or Saudi Refining, Inc. all of its interests in two joint ventures—Equilon[10] and Motiva[11]—through which Texaco had been competing with Chevron in gasoline marketing in the western and southern United States; (b) divest the refining, bulk supply, and marketing of gasoline satisfying California's environmental quality standards; (c) divest the refining and bulk supply of gasoline and jet fuel in the Pacific Northwest; and (d) divest the pipeline transportation of crude oil from the San Joaquin Valley of California.

A second important oil merger that the Commission recently challenged was the $6 billion merger between Valero Energy Corp. ("Valero") and Ultramar Diamond Shamrock Corp. ("Ultramar").[12] Both Valero and Ultramar were leading refiners and marketers of gasoline that met the specifications of the California Air Resources Board ("CARB gasoline") and were the only significant suppliers to independent sta-

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[5] Section 7 of the Clayton Act prohibits acquisitions where the anticompetitive effects may occur in "any line of commerce in any section of the country." 15 U.S.C. § 18.

[6] Figure 2 provides detailed information on all 15 of these Commission merger enforcement actions.

[7] In a number of other instances, the parties to a merger abandoned their transaction after the FTC opened an investigation into the transaction, but before formal Commission action.

[8] Federal Trade Commission Horizontal Merger Investigation Data, Fiscal Years 1996-2003 (Feb. 2, 2004), Table 3.1, et seq.; FTC Horizontal Merger Investigations Post Merger HHI and Change in HHI for Oil Markets, FY 1996 through FY 2003 (May 27, 2004), *available at* http://www.ftc.gov/opa/2004/05/040527petrolactionsHHIdeltachart.pdf.

[9] *Chevron Corp.,* Docket No. C-4023 (Dec. 18, 2001) (Consent Order).

[10] Shell and Texaco jointly controlled the Equilon venture, whose major assets included full or partial ownership in four refineries, about 65 terminals, and various pipelines. Equilon marketed gasoline through approximately 9,700 branded gas stations nationwide.

[11] Motiva, jointly controlled by Texaco, Shell, and Saudi Refining, consisted of their eastern and Gulf Coast refining and marketing businesses. Its major assets included full or partial ownership in four refineries and about 50 terminals, with the companies' products marketed through about 14,000 branded gas stations nationwide.

[12] *Valero Energy Corp.,* Docket No. C-4031 (Feb. 22, 2002) (Consent Order).

tions in California. The Commission's complaint alleged competitive concerns in both the refining and bulk supply of CARB gasoline in California, and the Commission contended that the merger could raise the cost to California consumers by at least $150 million annually for every one-cent-per-gallon price increase at retail.[13] To remedy the Commission's competitive concerns, the consent order settling the case required Valero to divest: (a) an Ultramar refinery in Avon, California; (b) all bulk gasoline supply contracts associated with that refinery; and (c) 70 Ultramar retail stations in Northern California.

As a third example, the Commission challenged the merger of Phillips Petroleum Company and Conoco Inc., alleging that the transaction would harm competition in the Midwest and Rocky Mountain region of the United States. To resolve that challenge, the Commission required the divestiture of: (a) the Phillips refinery in Woods Cross, Utah, and all of the Phillips-related marketing assets served by that refinery; (b) Conoco's refinery in Commerce City, Colorado (near Denver), and all of the Phillips marketing assets in Eastern Colorado; and (c) the Phillips light petroleum products terminal in Spokane, Washington.[14]

2. The GAO Report—In May of this year, the GAO released a report that sought to analyze how eight petroleum industry mergers or joint ventures carried out during the mid- to late 1990s affected gasoline prices.[15] The GAO reported that six of the eight transactions it examined caused gasoline prices to rise, while the other two transactions caused prices to fall.

The Commission reviewed a draft of the GAO report last summer.[16] Although GAO subsequently made some changes in its methodology, the basic criticisms we made of the draft report apply equally to the GAO's final report. The GAO report still contains major methodological mistakes that make its quantitative analyses wholly unreliable. It relies on critical factual assumptions that are both unstated and unjustified, and it presents conclusions that lack a quantitative foundation. Simply stated, the GAO report is fundamentally flawed.[17]

The Commission appends to today's testimony a detailed FTC staff analysis of the GAO report. That analysis highlights the GAO report's many flaws. Three particularly significant problems are noted here.[18] First, the GAO's models do not properly control for the numerous factors that cause gasoline prices to increase or decrease, and this failure to control for relevant variables significantly undermines any results of the GAO study. We cannot determine with precision the effects of this inadequate control on GAO's results, because GAO has refused to share with us the methodology and documentation (including data) to allow us to do so. Nevertheless, our Bureau of Economics has demonstrated that the GAO report did not account for several factors that affect gasoline prices, including changes in gasoline formulation and seasonal changes in demand. To the extent that these omitted variables

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[13] The Commission also alleged competitive concerns in the refining and bulk supply of CARB gasoline for sale in Northern California, contending that a price increase of one cent per gallon would increase costs to consumers in that area by approximately $60 million per year.

[14] *Conoco Inc. and Phillips Petroleum Corp.,* Docket No. C-4058 (Aug. 30, 2002) (Analysis of Proposed Consent Order to Aid Public Comment). Not all oil industry merger activity raises competitive concerns. For example, late last year, the Commission closed its investigation of Sunoco's acquisition of the Coastal Eagle Point refinery in the Philadelphia area without requiring relief. The Commission noted that the acquisition would have no anticompetitive effects and seemed likely to yield substantial efficiencies. *Sunoco Inc./Coastal Eagle Point Oil Co.,* FTC File No. 031-0139 (Dec. 29, 2003) (Statement of the Commission). The FTC also considered the likely competitive effects of Phillips Petroleum's proposed acquisition of Tosco. After careful scrutiny, the Commission by a 5-0 vote declined to challenge the acquisition. The FTC statement closing the investigation set forth its reasoning in detail. *Phillips Petroleum Corp.,* FTC File No. 001-0095 (Sept. 17, 2001) (Statement of the Commission).

Acquisitions of firms operating mainly in oil or natural gas exploration and production are unlikely to raise antitrust concerns, as that segment of the industry is generally unconcentrated. Acquisitions involving firms with de minimis market shares or production capacity or operations that do not overlap geographically are also unlikely to raise antitrust concerns. For example, the mere fact that a transaction involves a firm that meets the Energy Information Administration's financial reporting system threshold of "1% or more of the US reserves, production or refining capacity" or the Oil and Gas Journal's listing of the 200 largest publicly traded oil and gas corporations does not imply that the transaction raises competitive concerns.

[15] U.S. General Accounting Office, *Energy Markets: Effects of Mergers and Market Concentration in the U.S. Petroleum Industry* (May 2004) (hereinafter "GAO report").

[16] *See* Timothy J. Muris, Chairman, Federal Trade Commission, Letter to James E. Wells, Director, Natural Resources and Environment, U.S. General Accounting Office (Aug. 25, 2003), *available at* http://www.ftc.gov/opa/2004/05/040527petrolactionsFTCresponse.pdf.

The letter of August 25 was approved by a 5-0 vote of the Commission.

[17] The criticisms discussed here and in the detailed staff appendix have taken into account the explanations GAO has provided in response to the concerns the FTC had earlier raised.

[18] The Appendix explains in detail the additional analysis that our staff performed.

are correlated with concentration or mergers or other variables, these omissions bias the GAO's estimates of the effects of concentration and mergers on wholesale gasoline prices.

A second problem is that any reliable price-concentration study must be based on one or more properly defined geographic markets. If a merger affects competition, it does so in the particular geographic market in which that competition occurs. Unless the affected geographic area is correctly delineated, the researcher cannot have confidence that his results have anything to do with measured changes in concentration. If the market is defined too broadly or too narrowly, the researcher cannot accurately represent that any change in prices may have been caused by the change in measured concentration.

Through decades of experience, the Commission has developed substantial expertise in defining relevant geographic markets in which to measure concentration and competitive effects. Neither the draft GAO report nor the final report measures concentration in any properly defined geographic market. This problem is sufficient to deny the GAO report any validity in assessing the effect of concentration on prices.

Third, the GAO report fails to consider critical facts about the individual mergers it studied—omissions that render its results particularly suspect. For example, the relatively large and statistically significant price increases that the GAO report associates with the Exxon/Mobil merger appear implausible on their face, when considered in conjunction with the extensive restructuring effectuated by the Commission's consent order. Among other remedial measures, as a condition for allowing the transaction to proceed, the FTC required large-scale divestitures of Exxon and Mobil assets (including 1,740 retail outlets in the Northeast and Mid-Atlantic states, pipeline interests, terminals, jobber supply contracts, and brand rights) in the regions in which the GAO identified merger-related price increases. The divestitures essentially eliminated the competitive overlap between Exxon and Mobil in gasoline marketing in New England and the mid-Atlantic states south to Virginia (all in PADD I) and also eliminated marketing overlaps in parts of Texas (PADD III). Particularly with respect to branded prices, therefore, we strongly suspect that the merger cannot explain the GAO report's finding of higher wholesale prices following the Exxon/Mobil merger.

Despite these and other criticisms, we applaud the goal of the GAO inquiry—to evaluate the consequences of past decisions of the federal antitrust agencies. The Commission regards evaluations of past enforcement decisions as valuable elements of responsible antitrust policymaking. We welcome sound research to test our theoretical assumptions and analytical techniques. In the past the Commission has sponsored retrospective assessments of its work and has published the results, favorable and unflattering alike, because we believe such inquiries can improve our future competition policy programs. Over the past decade, we have sought the views of outsiders about how to strengthen this dimension of policymaking,[19] and we have increased our attention to retrospectives as a result.[20]

B. Nonmerger Investigations into Gasoline Pricing

In addition to scrutinizing mergers, the Commission aggressively polices anticompetitive nonmerger activity. When it appears that higher prices might result from collusive activity or from anticompetitive unilateral activity by a firm with market power, the agency investigates to determine whether unfair methods of competition have been used. If the facts warrant it, the Commission challenges the anticompetitive behavior, usually by issuing an administrative complaint.

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[19] The value of *ex post* evaluations was an important theme of the hearings convened by the FTC in the mid-1990s on innovation and globalization. See William E. Kovacic, *Evaluating Antitrust Experiments: Using Ex Post Assessments of Government Enforcement Decisions to Inform Competition Policy,* 9 Geo. Mason L. Rev. 843, 855 & n. 50 (2001). The benefits of increased efforts to analyze enforcement outcomes were emphasized in a roundtable of prominent industrial organization economists hosted by the FTC in 2001. *See* Federal Trade Commission, Empirical Industrial Organization Roundtable (Sept. 11, 2001), *available at* http://www.ftc.gov/be/empiricalioroundtabletranscript.pdf.

[20] *See e.g.,* Federal Trade Commission, Fulfilling the Original Vision: The FTC at 90, at 29 (Apr. 2004) (describing FTC retrospective studies of hospital mergers and petroleum mergers), *available at* http://www.ftc.gov/os/2004/04/040402abafinal.pdf; Harold Saltzman, Roy Levy & John C. Hilke, Transformation and Continuity: The U.S. Carbonated Soft Drink Bottling Industry and Antitrust Policy Since 1980 (Bureau of Economics Staff Report, Federal Trade Commission, Nov. 1999) (discussing impact of FTC merger enforcement involving soft drink bottlers), *available at* http://www.ftc.gov/reports/softdrink/softdrink.pdf; Staff of the Bureau of Competition of the Federal Trade Commission, A Study of the Commission's Divestiture Process (1999) (examining implementation of selected FTC merger consent orders), *available at* http://www.ftc.gov/os/1999/9908/divestiture.pdf.

Several recent petroleum investigations deserve discussion. On March 4, 2003, the Commission issued an administrative complaint, stating that it had reason to believe that the Union Oil Company of California ("Unocal") had violated Section 5 of the FTC Act. The Commission alleged that Unocal deceived the California Air Resources Board in connection with regulatory proceedings to develop the reformulated gasoline ("RFG") standards that CARB adopted. Unocal allegedly misrepresented that certain technology was non-proprietary and in the public domain, while at the same time it pursued patents that would enable it to charge substantial royalties if CARB mandated Unocal's technology in the refining of CARB-compliant summer RFG. As a result of Unocal's activities, the Commission alleged, Unocal illegally acquired monopoly power in the technology market for producing the new CARB-compliant summer RFG. The Commission also alleged that Unocal undermined competition and harmed consumers in the downstream product market for CARB-compliant summer RFG in California.

The Commission's complaint further charged that these activities, unless enjoined, could cost California's consumers hundreds of millions of dollars per year. The complaint cited testimony of Unocal's expert, who estimated that 90 percent of any royalty paid to Unocal for its technology would be passed on to drivers in the form of higher gasoline prices. This case was originally dismissed by an Administrative Law Judge, but the Commission has reversed the decision, reinstated the complaint, and remanded the case for a full trial.[21]

Another major nonmerger investigation occurred during 1998-2001, when the FTC conducted a substantial investigation of the major oil refiners' marketing and distribution practices in Arizona, California, Nevada, Oregon, and Washington (the "Western States" investigation). The agency initiated the Western States investigation out of concern that differences in gasoline prices in Los Angeles, San Francisco, and San Diego might be due partly to anticompetitive activities. The Commission's staff examined over 300 boxes of documents, conducted 100 interviews, held over 30 investigational hearings, and analyzed a substantial amount of pricing data. The investigation uncovered no basis to allege an antitrust violation. Specifically, the investigation detected no evidence of a horizontal agreement on price or output or the adoption of any illegal vertical distribution practice at any level of supply. The investigation also found no evidence that any refiner had the unilateral ability to raise prices profitably in any market or reduce output at the wholesale level. Accordingly, the Commission closed the investigation in May 2001.[22]

In performing these and other inquiries, the Commission distinguishes between short-term and long-term effects. While a refinery outage on the West Coast could significantly affect prices, the FTC did not find that it would be profitable in the long run for a refiner to restrict its output to raise the level of prices in the market. For example, absent planned maintenance or unplanned outages, refineries on the West Coast (and in the rest of the country) generally run at close to or full capacity. If gasoline is in short supply in a locality due to refinery or pipeline outages, and there are no immediate alternatives, a market participant may find that it can profitably increase prices by reducing its refinery output—generally for a short time only until the outage is fixed or alternative supply becomes available. This transient power over price—which occurs infrequently and lasts only as long as the shortage—should not be confused with the sustained power over price that is the hallmark of market power in antitrust law."

In addition to the Unocal and the West Coast pricing investigations, the Commission in 2001 issued a report on its nine-month investigation into the causes of gasoline price spikes in local markets in the Midwest in the spring and early summer of 2000.[23] The Commission found that a variety of factors contributed in different

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[21] Union Oil Company of California, Docket No. 9305 (Opinion of the Commission) (July 6, 2004), *available at* http://www.ftc.gov/os/adjpro/d9305/040706commissionopinion.pdf.

[22] FTC Press Release, *FTC Closes Western States Gasoline Investigation* (May 7, 2001), *available at* http://www.ftc.gov/opa/2001/05/westerngas.htm. In part, this investigation focused on "zone pricing" and "redlining." *See Statement of Commissioners Sheila F. Anthony, Orson Swindle and Thomas B. Leary, available at* http://www.ftc.gov/os/2001/05/wsgpiswindle.htm, and Statement of Commissioner Mozelle W. Thompson, available at http://www.ftc.gov/os/2001/05/wsgpithompson.htm, for a more detailed discussion of these practices and the Commission's findings. *See also* Cary A. Deck & Bart J. Wilson, *Experimental Gasoline Markets,* Federal Trade Commission, Bureau of Economics Working Paper (Aug. 2003), *available at* http://www.ftc.gov/be/workpapers/wp263.pdf, and David W. Meyer & Jeffrey H. Fischer, *The Economics of Price Zones and Territorial Restrictions in Gasoline Marketing,* Federal Trade Commission, Bureau of Economics Working Paper (Mar. 2004), *available at* http://www.ftc.gov/be/workpapers/wp271.pdf.

[23] Midwest Gasoline Price Investigation, Final Report of the Federal Trade Commission (Mar. 29, 2001), *available at* http://www.ftc.gov/os/2001/03/mwgasrpt.htm; *see also* Remarks of Jeremy

degrees to the price spikes. Primary factors included refinery production problems (*e.g.,* refinery breakdowns and unexpected difficulties in producing the new summer-grade RFG gasoline required for use in Chicago and Milwaukee), pipeline disruptions, and low inventories. Secondary factors included high crude oil prices that contributed to low inventory levels, the unavailability of substitutes for certain environmentally required gasoline formulations, increased demand for gasoline in the Midwest, and, in certain states, ad valorem taxes. Importantly, the industry responded quickly to the price spike. Within three or four weeks, an increased supply of product had been delivered to the Midwest areas suffering from the supply disruption. By mid-July 2000, prices had receded to pre-spike or even lower levels.

The Commission's merger investigations also are relevant to the detection of non-merger antitrust violations. FTC merger investigations since the mid-1990s uniformly have been major undertakings that have reviewed all pertinent facets of the relevant petroleum markets. These investigations have involved the review of thousands of boxes of documents in discovery, examination of witnesses under oath, and exhaustive questioning of outside experts. During these investigations, Commission staff have not only analyzed traditional merger issues but have also looked for evidence of potential anticompetitive effects related to unilateral market power, collusion, and ongoing illegal conduct.

The discussion above covers but a few of the gasoline pricing investigations to which the Commission has devoted substantial time and resources. To date, we have identified no instances of collusion among petroleum companies or of illegal unilateral firm conduct. Of course, that does not mean that anticompetitive acts cannot occur, which is why the agency continues to be vigilant in pursuing its enforcement mission.

C. Recent Commission Research on Factors That Can Affect Prices of Refined Petroleum Products

Prices of any commodity may fluctuate dramatically for reasons unrelated to antitrust violations. A sudden surge in demand or an unexpected problem in the supply chain can cause prices to spike quickly. A change in the price of a necessary input, such as crude oil, also can affect the price of the final good dramatically.

Such price changes are disruptive to both consumers and businesses but are not by themselves evidence of anticompetitive activity. They can occur in some regional gasoline markets because of a unique combination of short-run supply and demand conditions. The amount of gasoline that can be supplied to a particular region may be inflexible in the short run because of various limitations on refining and transportation capabilities or product requirements unique to that region. The demand for gasoline is inelastic.[24] Therefore, in the short run, changes in price do not heavily influence the amount of gasoline purchased by consumers. Under these conditions, when a sudden supply shortage jolts the market, perhaps due to a refinery fire or a pipeline rupture, the normal consequence of even a relatively small shortage of supply is a sharp increase in price until the supply of the product desired can be increased.

1. Gasoline Monitoring and Investigation Initiative—The Commission actively monitors wholesale and retail prices of gasoline. Two years ago, the FTC launched an initiative to monitor gasoline prices to identify "unusual" movements in prices[25] and then examine whether any such movements might result from anticompetitive conduct that violates Section 5 of the FTC Act. FTC economists developed a statistical model for identifying such movements. The agency's economists scrutinize price movements in 20 wholesale and over 350 retail markets across the country. A map of these markets is attached at Figure 3.

Our gasoline monitoring and investigation initiative focuses on the timely identification of unusual movements in gasoline prices (compared to historical trends) to determine if a law enforcement investigation is warranted. If the FTC staff detects unusual price movements in an area, it researches the possible causes, including, if appropriate, consulting with the state Attorneys General, state energy agencies, and the Department of Energy's ("DOE") Energy Information Administration. The

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Bulow, Director, Bureau of Economics, *The Midwest Gasoline Investigation, available at* http://www.ftc.gov/speeches/other/midwestgas.htm.

[24] Individual firms may have little or no market power even if industry demand is inelastic. It is a mistake to equate low demand elasticity with the ability of a firm to exercise market power. Elasticity is a measure of the percentage change in one variable (*e.g.,* quantity demanded) brought about by a one percent change in some other variable (*e.g.,* price). See Walter Nicholson, Microeconomic Theory: Basic Principles and Extensions 187-209 (4th ed. 1989).

[25] An "unusual" price movement in a given area is a price that is significantly out of line with the historical relationship between the price of gasoline in that area and the gasoline prices prevailing in other areas.

FTC staff also monitors DOE's gasoline price "hotline" complaints. If the staff concludes that the unusual price movement likely results from a "natural" cause (*i.e.,* a cause unrelated to anticompetitive conduct), it does not investigate further.[26] The Commission's experience from its past investigations and the current monitoring initiative indicates that unusual movements in gasoline prices typically have a natural cause. FTC staff further investigates unusual price movements that do not appear to be explained by "natural" causes to determine whether anticompetitive conduct may be a cause. Cooperation with state law enforcement officials is an important element of such investigations.

Regional price spikes for gasoline have occurred in various parts of the country, and many areas have experienced substantial price increases for gasoline in recent months. As noted above, the FTC is monitoring wholesale and retail gasoline prices in cities throughout the country and will continue to analyze these data to seek explanations for pricing anomalies. A look at some recent price spikes illustrates the kinds of factors, other than crude oil prices, that affect retail price levels.

a. *ARIZONA*

In August 2003, gasoline prices rose sharply in Arizona. The average price of a gallon of regular gasoline in Phoenix rose from $1.52 during the first week in August to a peak of $2.11 in late August. Several sources caused these price movements. Most gasoline sold in Phoenix comes from West Coast refineries. A pipeline from Texas also brings gasoline to the Phoenix area, but it usually operates at capacity. The marginal supply comes from the West Coast.[27]

Product supplies on the West Coast were already becoming tight in early August, following a number of unplanned refinery interruptions in California and an unplanned shutdown at a refinery in Washington. This placed upward pressure on prices on the West Coast and in Arizona. On July 30, 2003, Kinder Morgan's El Paso-to-Phoenix pipeline ruptured between Tucson and Phoenix. On August 8, Kinder Morgan shut down the pipeline, after its efforts to repair the rupture failed. This disruption immediately reduced the volume of gasoline delivered to Phoenix by 30 percent, and most of Arizona immediately became much more dependent on shipments from California for its gasoline supplies.

Retail prices in Phoenix increased during the week immediately following the August 8 pipeline shutdown (the week ending August 16) to levels higher than predicted by historical relationships.[28] As California refineries increased supply shipments to Arizona (displacing refining capacity that could otherwise serve California markets), retail prices in Los Angeles increased above the predicted level during the week ending August 23. On August 24, Kinder Morgan opened a temporary by-pass of the pipeline section affected by the rupture, and prices quickly fell. The average price of regular gasoline began to drop immediately. By the end of August, gasoline prices in the Phoenix area were falling. They continued to drop through September and October.[29] (See Figure 4.)

Marked price increases in the wake of a sudden, severe drop in supply are a normal market reaction. Because gasoline is so important to consumers, a large price increase may be required to reduce quantity demanded so that it is equal to available supply. Price increases in turn attract additional supplies, which should then cause prices to decline. This response occurred in the Kinder Morgan rupture.

b. *ATLANTA*

Another recent price anomaly picked up by the monitoring project occurred in Atlanta, Georgia, and surrounding counties. This anomaly is not the traditional price spike that attracts the public's attention. Instead, it took the form of a small, sustained increase. Atlanta and its surrounding counties have experienced gasoline formulation changes in the past few years that have differentiated it from the rest of

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[26] Natural causes include movements in crude oil prices, supply outages (*e.g.,* from refinery fires or pipeline disruptions), or changes in and/or transitions to new fuel requirements imposed by air quality standards.

[27] Marginal supply is the last product brought into a market and effectively sets the equilibrium price. It is also the increment of product that can adjust in the short run to market conditions and thus ameliorate price spikes.

[28] Price increases in Phoenix were not large enough to equate short-run supply and demand. Gasoline was effectively rationed by queuing—long lines of motorists—and many stations ran out of gasoline. *See Phoenix Gas Crisis Worsens,* MSNBC News (Aug. 21, 2003) (only 45 percent of retail stations had product to sell), *available at* http://www.msnbc.com/local/AZSTAR/A1061452904.asp?0cv=BB10; *Phoenix Gas Stations Running Dry After Pipeline Shut Down,* Associated Press (Aug. 18, 2003), *available at* http://www.cnn.com/2003/US/Southwest/08/18/phoenix.gas.crunch.ap/.

[29] In examining this pricing anomaly, the FTC staff consulted with the Attorney General offices in Arizona and California.

the Southeast. On April 1, 2003, an interim low-sulfur standard of 90 parts per million ("ppm") took effect. Soon thereafter, Georgia required the 45-county area surrounding Atlanta to introduce a new 30 ppm low-sulfur gasoline by September 16. These formulation changes increased the cost of producing gasoline. After the 90 ppm standard was implemented, gasoline prices in Atlanta increased.

After the 90 ppm standard was instituted in April, and even more frequently after the 30 ppm standard was instituted in September, the Commission's monitoring project picked up small anomalies in Atlanta gasoline pricing. Atlanta and the surrounding area have experienced slightly higher prices relative to historical levels because of the greater costs of making low-sulfur gasoline. This increase is illustrated at Figure 5.

c. *MID-ATLANTIC AREA*

A third pricing anomaly occurred in September and October of last year. Gasoline prices were generally falling nationwide at that time. The price of reformulated gasoline in the New York, New Jersey, Connecticut, and Philadelphia areas, however, declined more slowly than the price of gasoline in the rest of the country. The FTC monitoring model showed the price of gasoline in this region was unusually high even though prices were decreasing elsewhere. (See Figure 6.)

The FTC staff's examination of this anomaly, which included consultation with each affected state's Attorney General, ultimately concluded that the elevated price in this area stemmed from a number of factors. In late August 2003, the Northeast was hit particularly hard by an increase in demand that drew down gasoline stocks in all regions of the United States.[30] The August 14 blackout further affected the Northeast, temporarily shutting down seven refineries. While the blackout appeared to have little immediate impact on U.S. retail gasoline prices, the reduction in supply from four refineries in Ontario, Canada, whose operations were hampered by the power outage, significantly affected the price of gasoline in Ontario. Typically, the Northeastern states receive significant gasoline imports from Canada. Throughout much of August, however, wholesale prices in Toronto exceeded wholesale prices in Buffalo by approximately 25 cents per gallon, a sign that Canada was shipping less product into the Northeast. FTC staff confirmed a sizeable drop in exports of gasoline from Canada to the Northeast in August 2003.[31] By the end of September, rack prices in Toronto and Buffalo had returned to rough equality, and imports from Canada returned to their usual level.

On top of the low inventories, both the switch from summer to winter grade gasoline and the switch in New York and Connecticut from MTBE-blended[32] reformulated gasoline to ethanol RFG caused a disincentive to build inventories in August and September. While refineries in the Northeast increased production during this period, important additional supply to this area comes by pipeline from the Gulf and imports from abroad. Both of these sources of supply require significant response times, however. Given the shipping lags and the impending switches in formulation, there was limited time—as well as a disincentive—to ship additional summer specification RFG to the Northeast.

d. *WESTERN STATES*

FTC staff identified a pricing anomaly involving the Western United States during February and March 2004. Figures 7 through 10 show the actual and predicted bounds of the price of retail gasoline in Las Vegas and Reno, Nevada, and Los Angeles and San Francisco, California. Figures 11 and 12 show the actual and predicted range of the wholesale price of gasoline in Los Angeles and San Francisco, respectively.[33]

As shown on the graphs, the wholesale (rack) price of gasoline in California increased beginning in mid-February. By the third week in February, the wholesale prices were outside the predicted bounds. The retail prices in Nevada and California followed a similar path, but the daily data showed a more lagged response. As part of the monitoring and investigation initiative, FTC staff discussed the anomalies with the California Energy Commission, DOE's Energy Information Administration, the California Attorney General's Office and the Nevada Attorney General's Office. The FTC also examined additional sources of data.

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[30] DOE, *Inquiry into August 2003 Gasoline Price Spike,* at 35-42 (Nov. 2003).

[31] FTC staff compiled the import data from tariff and trade data from the U.S. Department of Commerce, the U.S. Department of the Treasury, and the U.S. International Trade Commission.

[32] "MTBE" is Methyl Tertiary-Butyl Ether.

[33] Information for the wholesale price of gasoline is provided because Nevada receives its gasoline by pipeline from both Los Angeles and San Francisco.

FTC staff found that a number of factors caused the price spike. Unanticipated refinery outages took place at a time when there were also relatively low levels of inventory. Some outages resulted when maintenance lasted longer than expected, while one outage resulted from a power failure. January through March is the normal time for refinery maintenance, when firms are preparing for the summer gasoline season. California refineries operate at near capacity most of the year but perform maintenance during the winter, during the downturn in demand.[34]

Examining the gasoline inventory and production levels in California, as well as the prices in California relative to the Gulf Coast, illuminates the relevant sequence of events. Figure 13 shows (a) weekly gasoline production at the California refineries as a percentage of the previous year's gasoline production, (b) gasoline and blending stock inventories as a percentage of the previous year's inventories, (c) the Los Angeles and Houston rack (price) differential as a percentage, and (d) the average Los Angeles to Houston rack (price) differential as a percentage.[35]

Figure 13 shows that in the first few weeks of January, gasoline production in California was 10 to 20 percent higher than in January 2003, leading to higher inventories.[36] As production dropped in late January because of scheduled maintenance, inventories were drawn down. During January the rack price of gasoline in Los Angeles was below the normal Houston-Los Angeles differential, indicating lower relative prices in Los Angeles than in Houston, due to this increased production. As inventories dropped in early February, the rack price in Los Angeles began to increase, relative to Houston. In mid-February, the Tesoro refinery in San Francisco had a power outage that shut the refinery for a week,[37] and Valero announced that restarting a refinery that had been undergoing maintenance would take an extra week. There were additional refinery outages as well.[38] The combined effect of the decreased production and lower-than-expected inventories was that the Los Angeles rack price rose substantially relative to Houston, and Los Angeles retail prices also rose beyond what would be expected at a time of dramatically increasing crude oil prices. As the refineries were brought back online, the relative wholesale price of gasoline in California fell, and retail prices moved more in line with prices nationwide (a relative decrease, compared to the rest of the country).

Restarting a refinery is a lengthy process that can take a week or more, and the loss of output from a refinery outage can be sizeable. Refiners have contractual obligations to supply branded stations, and a refinery with a major outage may have to purchase gasoline from its competitors at the current price. During the incident discussed above, three of the California refineries that experienced difficulties in restarting were forced to make unplanned purchases totaling a million barrels of gasoline on the spot market.[39]

2. Conferences and Staff Reports Identifying Factors Affecting the Price of Gasoline—Because of increased public concern about the level and volatility of gasoline prices, the Commission constantly studies factors that can affect refined petroleum product prices. The Commission held public conferences in 2001 and 2002[40] that made important contributions to our knowledge about the factors that affect gasoline prices. The Commission is preparing a report on the proceedings of these conferences and related work.

The Commission also is updating its 1982 and 1989 petroleum merger reports to focus on mergers and structural change in the oil industry since 1985. In March, Commission staff economists released a retrospective study of the effects of the Marathon-Ashland joint venture in Kentucky.[41] This paper examines the price effects

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[34] Testimony of Pat Perez, California Energy Commission, before the California Attorney General's Task Force on Gasoline Prices (Mar.11, 2004), *available at* http://www.energy.ca.gov/papers/2004-03-11_PAT_PEREZ.PDF.

[35] Houston is a major refining area. The price comparison is between the current price difference between Los Angeles and Houston and the historical difference. When the price differential between Los Angeles and Houston increases above the historical difference, it is important to research the cause of the deviation.

[36] It is not unusual for annual "week to week" comparisons to show such differences. Data on weekly refinery production and output are available from the California Energy Commission, Weekly Fuels Watch Report Database, *available at* http://www.energy.ca.gov/database/fore/index.html.

[37] Oil & Gas Journal (Mar.1, 2004).

[38] Testimony of Pat Perez, *supra* note 34; *see also* California Energy Commission, Questions & Answers: California Gasoline Price Increases, *available at* http://www.energy.ca.gov/gasoline/gasoline—q-and-a.html.

[39] California Energy Commission, *supra* note 38.

[40] FTC Press Release, *FTC to Hold Second Public Conference on the U.S. Oil and Gasoline Industry in May 2002* (Dec. 21, 2001), *available at* http://www.ftc.gov/opa/2001/12/gasconf.htm.

[41] Christopher T. Taylor & Daniel S. Hosken, *The Economic Effects of the Marathon-Ashland Joint Venture: The Importance of Industry Supply Shocks and Vertical Market Structure,* Fed-

of the Marathon-Ashland joint venture by comparing the wholesale and retail prices of gasoline in a number of regions unaffected by the merger to prices of gasoline in Louisville, Kentucky. The transaction does not seem to have affected the relative price of gasoline in Louisville.

III. FACTORS AFFECTING GASOLINE PRICES

Through its merger and nonmerger enforcement activity, and through its conferences, studies, and advocacy work, the FTC has examined in detail the central factors that may affect the level and volatility of refined petroleum product prices. Below we review just a few of those factors.

The most important factor affecting both the level and movement of gasoline prices in the United States is the price of crude oil.[42] Changes in crude oil prices account for approximately 85 percent of the variability of gasoline prices.[43] When crude oil prices rise, gasoline prices rise. (See Figure 1.) Crude oil prices are determined by supply and demand conditions worldwide, most notably by production levels set by OPEC countries.[44] Other factors that affect the supply of and demand for crude oil, such as the fast-growing demand for petroleum in China, also influence the price of gasoline in the United States.

Inventories of both crude oil and refined products also have an important effect on retail gasoline prices. At our August 2001 conference,[45] a representative of the Energy Information Administration reported that "OPEC [production] cuts and high crude prices affect gasoline prices directly through the feedstock cost but also indirectly by reducing gasoline inventories."[46] Participants also commented that average inventories for refined products have declined over time,[47] contributing to price spikes as additional supply is less available quickly to meet demand. Lower inventory costs decrease the average cost of producing gasoline, to the benefit of consumers.[48]

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eral Trade Commission, Bureau of Economics Working Paper (Mar. 2004), *available at* http://www.ftc.gov/be/workpapers/wp270.pdf.

[42] While the impact of crude oil prices on gasoline prices is widely recognized, it is often alleged that gasoline prices are "sticky downward"—that is, gas prices go up like "rockets" and come down like "feathers" in response to changes in oil prices. For a review of the empirical literature testing this hypothesis, see John Gewecke, *Issues in the "Rockets and Feathers"* Gasoline Price Literature, submitted in conjunction with the Federal Trade Commission Conference, *Factors That Affect the Price of Refined Petroleum Products II* (May 8, 2002), *available at* http://www.ftc.gov/bc/gasconf/comments2/gewecke2.pdf. This paper indicates there are serious and sometimes fundamental flaws with the papers showing asymmetric response.

[43] *See* note 2, *supra*.

[44] OPEC members today account for 40 percent of world crude oil production and 80 percent of world crude oil reserves. As a substantive matter, competitor cartels that limit supply or fix prices are illegal under U.S. antitrust laws. However, the U.S. antitrust agencies must account for considerations beyond the substantive merits of a case before bringing such a lawsuit. *See* Federal Trade Commission, Prepared Statement, *Competitive Problems in the Oil Industry,* Before the Committee on the Judiciary, United States House of Representatives (Mar. 29, 2000).

The share of world crude oil production accounted for by U.S.-based companies declined from 10.8 percent in 1990 to 8.5 percent in 2003; the share of these firms is similarly low for world crude oil reserves. Recent large mergers among major oil companies have had little impact on concentration in world crude oil production and reserves. For example, Exxon and Mobil, which merged in 1999, had worldwide shares of crude oil production in 1998 of 2.1 percent and 1.3 percent, respectively; in 2001, the combined firm's share was 3.4 percent. The BP/Amoco merger combined firms with world crude oil reserves of 0.7 percent and 0.2 percent in 1997; the combined firm's world crude oil reserve share in 2001, which reflects the acquisition of ARCO in 2000 and the divestiture of ARCO's Alaska North Slope crude oil to Phillips, was 0.8 percent.

[45] Transcripts of the conference and papers submitted to the *Federal Trade Commission Public Conference: Factors that Affect Prices of Refined Petroleum Products,* are available at http://www.ftc.gov/bc/gasconf/index.htm. The dates of the conferences were August 2, 2001, and May 8 and May 9, 2002.

[46] John Cook (EIA), Aug. 2 tr. at 52.

[47] Thomas Greene (California Attorney General Office), Aug. 2. tr. at 11 ("[i]n the 1990's, reserves and inventories [in California] have declined roughly 20-plus percent"); Rothschild (Podesta/Mattoon), Aug. 2 tr. at 82 (consistently below an average of 5 days of gasoline inventory); Mark Cooper (Cons. Fed. of Am.), written statement at 21.

[48] In a recent study of the petroleum inventory system, the National Petroleum Council concluded that the trend toward lower product inventories was "the result of improved operating efficiencies partially offset by operational requirements for an increased number of product formulations to comply with environmental regulations," noting also that "[s]ince holding inventory is a cost, there is an underlying continuous pressure to eliminate that which is not needed to meet customer demand or cannot return a profit to the holder." National Petroleum Council, *U.S. Petroleum Product Supply—Inventory Dynamics,* at 11 (Dec. 1998). The National Petroleum Council study also concluded that "[c]ompetition has resulted in the consumer realizing essentially all of the cost reductions achieved in the downstream petroleum industry." *Id.* at 22.

Participants in the FTC conference also noted that refineries and the pipelines used to transport gasoline to the pump are typically highly utilized. The annual average domestic refinery atmospheric distillation capacity utilization rate reached record levels in 1997 (95.2 percent) and 1998 (95.6 percent) after rising fairly steadily since the early 1980s.[49] In more recent years, annual average distillation capacity utilization has eased somewhat, falling to 92.5 percent for 2003. However, refinery distillation capacity utilization for the four-week period ending June 18, 2004 (the most recent period for which data are available) was 95.7 percent.[50]

Although it is efficient to run these capital-intensive facilities at high rates of capacity utilization, supply disruptions from unexpected refinery outages or pipeline failures may not be easily or immediately compensated for by other supply sources due to capacity limitations, resulting in substantial market price effects in some cases.

Total refinery distillation capacity has been increasing in recent years, however. Total distillation capacity was 15.43 million barrels per day ("MMBD") in 1995.[51] As of June 2004, industry distillation capacity was 16.89 MMBD.[52] While no new U.S. refineries were built during this period, the increase of over 1.4 MMBD of industry capacity at existing facilities represents a 9.5 percent increase since 1995. This is equivalent to adding more than 12 average-sized refineries to industry supply.[53] Over time, there has been a noticeable shift toward running larger refineries.[54] While some refineries have closed since 1995, these mainly were small, older refineries with limited gasoline production capacity.[55] Despite these closures, refining capacity in each PADD has increased since 1995.[56]

Pipeline capacity also is stretched in some regions of the country for at least parts of the year, although various pipeline expansion projects now underway may relieve some pressure. In addition to capacity increases and upgrades at the refinery level, there have been increases in product pipeline capacities in recent years.[57]

Conference participants indicated that the interaction of environmental quality requirements and gasoline supplies may also affect gasoline prices. It is clear that environmental regulations have yielded substantial air quality benefits. Since 1970, emissions of the six principal air pollutants—nitrogen dioxide, ozone, sulfur dioxide, particulate matter, carbon monoxide, and lead—have been cut by 25 percent, even as vehicle miles increased by 149 percent.[58] These regulations add to the cost of refining crude oil, and thus to gasoline prices. The Environmental Protection Agency estimates that the cost of producing a gallon of reformulated gasoline is 4 to 8 cents per gallon more than the cost of producing conventional gasoline.[59] These costs may be even higher during supply disruptions, when significant marginal costs are incurred as firms attempt quickly to alter previously determined production runs.

In addition, several participants at the FTC conferences reported that the proliferation of different environmentally mandated gasoline blends has reduced the ability of firms to ship gasoline from one region to another in response to supply disruptions.[60] (Figure 16 illustrates the different fuel blends required in the United

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[49] EIA, *Annual Energy Review 2002,* Table 5.9.

[50] EIA, *Weekly Petroleum Status Report,* June 23, 2004, Table 2. Annual capacity utilization for 2003 is based on average of reported monthly capacity utilization rates.

[51] EIA, *Annual Energy Review 2002,* Table 5.9.

[52] EIA, *Weekly Petroleum Status Report,* June 23, 2004, Table 2.

[53] The average size of a refinery in 2003 was 112.5 thousand barrels per day ("MBD"). The average size of a refinery in 1995 was 88.2 MBD.

[54] *See* Figure 14, Size Distribution of Operating Refineries 1986 and 2003.

[55] *See* Figure 15, Refinery Closures, 1995 to 2003, showing crude oil distillation capacity of closed refineries.

[56] *See* EIA, *Petroleum Supply Annual 1996* (Table 36); EIA, *Weekly Petroleum Status Report,* Table 2, U.S. Petroleum Activity, January 2003 to present.

[57] For example, the FTC examined bulk product supply conditions affecting the Midwest in its investigation of price spikes affecting that area in the spring of 2000. Since that time product pipeline capacity from the Gulf to the Midwest has increased significantly. The Centennial pipeline, with a capacity of 210 MBD, opened in 2002. *See* Marathon Oil Company, *Marathon Ashland Petroleum, LLC, available at* http://www.marathon.com/Our__Business/Marathon__Ashland__Petroleum__LLC/.

Explorer, another major pipeline bringing refined products from the Gulf to the Midwest, added 110 MBD of capacity in an expansion project that was completed in 2003. See Willbros Group Inc., Explorer Mainline Expansion, available at http://www.willbros.com/pdf/0277.pdf.

[58] Environmental Protection Agency, *Air Quality and Emissions Trends Report* (2002).

[59] Robert Larson (EPA), May 8 tr. at 74.

[60] *E.g.,* John Felmy (American Petroleum Institute), Aug. 2 tr. at 26; Benjamin Cooper ("Ass'n of Oil Pipe Lines), Aug. 2 tr. at 102. According to one participant, "[t]ight specifications for reformulated gasoline sold in [California] and limited pipeline interconnections . . . isolate the California gasoline market from gasoline markets in the rest of the country," thus contributing to higher prices in the state. Richard Gilbert (U. Cal. Berkeley), written statement at 3-4.

States.[61]) The FTC staff's analysis of pricing anomalies, discussed earlier, provides support for these concerns. As part of its work to improve public understanding of the possible role of environmentally mandated fuels in contributing to price volatility and price spikes, Commission staff provided comments to the EPA in connection with that agency's preparation of the EPA Staff White Paper, a response to the President's National Energy Report (May 2001). The President's Report directed the EPA Administrator to "study opportunities to maintain or improve the environmental benefits of state and local 'boutique' fuels programs, while exploring ways to increase the flexibility of the fuels distribution infrastructure, improve fungibility, and provide added gasoline market liquidity."[62] The FTC staff commented that the EPA might find it beneficial to use a framework similar to the one the FTC uses to analyze mergers, to determine the competitive effects likely to result from changes in fuel mandates in particular relevant markets.[63] The FTC staff offered suggestions to the EPA concerning how it might perform such an analysis.

Other federal and state laws and regulations were identified by conference participants as affecting gasoline prices. For example, a federal statute known as the Jones Act[64] increases the cost of transporting petroleum products by requiring that any product transported by vessel between U.S. ports be carried in domestically-built ships staffed by U.S. crews, which is more expensive than carriage by foreign-built, foreign-staffed ships. A recent government estimate of the total welfare cost of the Jones Act for all tanker shipping is $656 million per year, based on the assumption that a foreign ship has operating costs of only 59 percent of a Jones Act ship.[65] The observed cost of transportation of refined petroleum products from the Gulf Coast to the West Coast, 10-25 cents per gallon,[66] implies that the Jones Act imposes an additional cost of at least 4 cents per gallon when it is necessary to transport gasoline using Jones Act ships.

A number of states have also adopted statutes or regulations that substantially influence gasoline prices. Several states have divorcement statutes that require the unbundling of retail sales from upstream refining operations. Careful economic analyses of divorcement statutes have concluded that such statutes can increase consumer prices.[67] Other regulatory statutes that appear to have increased gasoline prices include bans on self-service sales[68] and restrictions on below-cost sales,[69]

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[61] A number of different fuel blend requirements have been introduced since passage of the Clean Air Act of 1990. For example, regulations governing fuel blends in California have been introduced and implemented in 1992, 1996 and 2003 (CARB I, II, and III.). Additionally, RFG Phase 1 (1995) and RFG Phase 2 (2000) affect various other states. Tier 2 low-sulfur gasoline regulations are being phased in now. Additionally, various regional specifications have been phased in over the last decade.

[62] *Study of Unique Gasoline Fuel Blends ("Boutique Fuels"), Effects on Fuel Supply and Distribution and Potential Improvements,* EPA Staff White Paper at 1-2.

[63] The FTC's experience shows that economically relevant gasoline markets are regional for refining and transportation, and local for gasoline distribution or retail sales. For example, a refinery that does not—or cannot in the short run—produce the type of gasoline currently in short supply in a certain region cannot be considered to be in that market for purposes of resolving short-run price spikes. FTC Staff Comments, Study of Unique Gasoline Fuel Blends ("Boutique Fuels"), Effects on Fuel Supply and Distribution and Potential Improvements, Dkt. No. A-2001-20, Before the Environmental Protection Agency at 4 (Jan. 30, 2002).

[64] Sec. 27 of the Merchant Marine Act of 1920, as amended, 46 App. U.S.C. § 883; *see also* 19 C.F.R. §§4.80, 4.80b.

[65] The Economic Effects of Significant U.S. Import Restraints, U.S. International Trade Commission, Pub. No. 3519 (June 2002).

[66] California Energy Commission, Gulf Coast to California Pipeline Feasibility Study (Aug. 2003).

[67] *See* Michael G. Vita, *Regulatory Restrictions on Vertical Integration and Control: The Competitive Impact of Gasoline Divorcement Policies,* 18 J. Reg. Econ. 217 (2000) (finding that retail gasoline prices are two to three cents per gallon higher in states with divorcement laws); Asher A. Blass & Dennis W. Carlton, *The Choice of Organizational Form in Gasoline Retailing and the Cost of Laws that Limit that Choice,* 44 J. L. & Econ. 511 (2001) (estimating that divorcement increases costs of operation by about three to four cents per gallon) .

[68] *See* Vita, *supra* note 67 (noting that in 1993—at that time the last year for which data were available—the price of regular unleaded gasoline in those states that banned self-service was three cents per gallon higher than in states that allowed self-service); see also R. Johnson & C. Romeo, *The Impact of Self-Service Bans in the Retail Gasoline Market,* 82 Rev. Econ & Stat. 625 (2000) (finding the cost of self-service bans to be three to five cents per gallon).

[69] The Minnesota Department of Commerce recently ordered Kwik Trip, Inc., and Murphy Oil USA Inc. to Acease and desist" from selling gasoline at too low a price. The allegation in both cases was that the respondent had Aengaged in the offer and sale of gasoline below the minimum allowable price." Minnesota Department of Commerce, *Enforcement Actions* May 2004, *available at* http://www.state.mn.us/mn/externalDocs/Commerce/Enforcement_Actions_May__2004__050704120541__EnfAct053104.htm; *see also* Mark Brunswick, *Selling Gas For Too Lit-*

Continued

which appear simply to protect retailers from competition from more efficient competitors.[70] The FTC staff has provided numerous comments on specific sales-below-cost legislation, noting that (a) economic studies, legal studies, and court decisions indicate that belowcost pricing that leads to monopoly or anticompetitive harm occurs infrequently; (b) belowcost sales of motor fuel that lead to monopoly or anticompetitive harm are especially unlikely; and (c) alleged instances of anticompetitive below-cost sales are best addressed by federal statutes against anticompetitive conduct to avoid chilling procompetitive and pro-consumer conduct.[71]

Mr. HALL. Mr. Kovacic, thank you. I will recognize myself for 5 minutes. Mr. Caruso, in your testimony, you state refiners today must make huge environmental investments to stay in business. Just generally, if you would, explain what these investments are and how they might affect an individual company or their board of directors to say, "To heck with it, we are going to shut down," or "How can we expand and stay in business?"

Mr. CARUSO. Well, I think there are at least two aspects to the investment. One, of course, as Mr. Holmstead pointed out, considers the number of changes in the specifications required for RFG as well as Tier 2 standards, so that the actual configuration within the refineries have had to be changed to meet these requirements. And then, of course, there are increasingly stringent requirements, oftentimes by State and local regulators, to make sure that the refinery emissions, et cetera, are up to the standard. So, there are two aspects of that.

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tle Can Be Costly; State Regulations Are Penalizing Some Retailers Who Don't Charge Enough For Fuel, Minneapolis Star-Tribune, at 1B (June 2, 2004).

[70] *See, e.g.,* Star Fuels Mart, LLC v. Sam's East, Inc., 2004 U.S. App. LEXIS 5215, at *17 n.3 (10th Cir. Mar. 19, 2004) (despite no evidence of harm to competition under a Sherman Act standard, upholding temporary injunction granted under the Oklahoma Unfair Sales Act forbidding defendant from selling fuel below cost because "[t]he purpose of the OUSA . . . is simply to prevent loss leader selling and to protect small businesses").

Hypermarkets are transforming gasoline retailing. Hypermarkets, which are high-volume retail outlets mostly owned by or leased from grocery stores, mass merchandise retailers, large convenience stores, or membership clubs, have substantial economies of scale that enable them to sell at low prices. They may pump up to one million gallons of fuel a month. Some hypermarkets can reduce their costs further by doing their own wholesaling, and some already buy their gasoline directly from refineries through long-term contracts. As of the fourth quarter of 2002, the national market share for hypermarkets was approximately six percent. See Energy Analysts International, Evolution of the High Volume Gasoline Retailer (Feb. 13, 2003).

[71] *See* Letter from Susan Creighton, Director, FTC Bureau of Competition, et al., to Michigan State Representative Gene DeRossett (June 17, 2004), *available at* http://www.ftc.gov/os/2004/06/040618staffcommentsmichiganpetrol.pdf; Letter from Susan Creighton, Director, FTC Bureau of Competition, et al., to Kansas State Sen. Les Donovan (Mar. 12, 2004), *available at* http://www.ftc.gov/be/v040009.pdf; Letter from Susan Creighton, Director, FTC Bureau of Competition, et al., to Demetrius Newton, Speaker Pro Tempore of the Alabama House of Representatives (Mar. 12, 2004), *available at* http://www.ftc.gov/be/v040005.htm; Letter from Susan Creighton, Director, FTC Bureau of Competition, et al., to Wisconsin State Rep. Shirley Krug (Oct. 15, 2003), *available at* http://www.ftc.gov/be/v030015.htm; Letter from Joseph J. Simons, Director, FTC Bureau of Competition, et al., to Eliot Spitzer, Attorney General of New York (July 24, 2003), *available at* http://www.ftc.gov/be/nymfmpa.pdf; Letter from Joseph J. Simons, Director, FTC Bureau of Competition, et al., to Roy Cooper, Attorney General of North Carolina (May 19, 2003), *available at* http://www.ftc.gov/os/2003/05/ncclattorneygeneralcooper.pdf; Competition and the Effects of Price Controls in Hawaii's Gasoline Market: Before the State of Hawaii, J. Hearing House Comm. On Energy and Environmental Protection et al. (Jan. 28, 2003) (testimony of Jerry Ellig, Deputy Director, FTC Office of Policy Planning), available at http://www.ftc.gov/be/v030005.htm; Letter from Joseph J. Simons, Director, FTC Bureau of Competition, et al., to Gov. George E. Pataki of New York (Aug. 8, 2002), *available at* http://www.ftc.gov/be/v020019.pdf; Letter from Joseph J. Simons, Director, FTC Bureau of Competition, and R. Ted Cruz to Hon. Robert F. McDonnell, Commonwealth of Virginia House of Delegates (Feb. 15, 2002), *available at* http://www.ftc.gov/be/V020011.htm.IV. ConclusionCompetition policy helps ensure that the petroleum industry is, and remains, competitive. The FTC has expended substantial effort and resources to enforce the antitrust laws and to scrutinize behavior in this industry. We will continue to do so in the future. Higher prices for petroleum products deeply affect the quality of life in the United States and strongly influence the Nation's economic performance. Understanding and publicizing developments in this sector, and attacking conduct that violates the antitrust laws, are competition policy priorities second to none for the Federal Trade Commission. I would be pleased to answer your questions.

And the reason this is so important in the outlook for the refinery capacity in this country is that we had a large number of small refineries built in this country. The peak amount of capacity was in 1981 when we had about 350 refineries. We are down to 149 now. And many small refineries closed just because they weren't efficient and they were living on tax credits. But the other reason was that the requirements to invest to meet these new standards and requirements were just not possible for them to do and earn an appropriate rate of return, so many small refiners have closed and, indeed, the need to become larger has clearly been demonstrated in that the average capacity in this country per refinery has been creeping up while the total number of refineries has declined significantly.

Mr. HALL. Do you find any reticence or reluctance on the part of those who operate the refineries, to initiate or pursue the need for more refineries? Are they satisfied to set where they are and with the lack of refineries have some effect on the price?

Mr. CARUSO. I think we have seen pretty clearly, certainly in the last 10 years, that a number of refiners have expanded capacity to take advantage of this growing marketplace, and so I think they are looking for business opportunities but, clearly, they have to have the incentives. The rate of return that we witnessed in the 1990's in particular was extremely low, and, therefore, you saw what I think was a rational economic decision to, in some cases, close, in other cases either get bigger or leave an area. And so, I think that also, led to incentives to some of the mergers that have taken place, to take advantage of economies of scale in various regions.

So, I think the refiners are looking for opportunities, but clearly it has to be a better use of that money than to invest it in another aspect of this business or another business.

Mr. HALL. Or do you see refineries whose management is not pleased with the treatment they get from the Federal Government in a lot of instances, not enough incentives? I think this committee held a hearing on that very thing several weeks ago, to give incentives to upgrade the facilities where they are, among other reasons, to people that are more amenable to less complaints than they would be if they went to a new area to open up. You have all those things, I guess, to look into.

I think my time is about up. At this time, I recognize Mr. Green for 5 minutes.

Mr. GREEN. Thank you, Mr. Chairman. Mr. Caruso—Mr. Waxman—I don't know if we still have those graphs, but did you see his EIA production estimates based on the energy bill? Did you feel like that was correct in the production estimates, if the Energy Bill actually passed?

Mr. CARUSO. Yes. I am glad you asked that question because I would like to clarify that. The EIA analyzed the Conference Energy Bill; those components of that Conference Energy Bill that were quantifiable and able to be used in our National Energy Modeling System. Unfortunately, there were a number of other provisions in the bill which were not quantifiable because the amount of money or the timing wasn't clear. There were some things such as the electric reliability provisions, the MTBE liability waiver, the R&D

incentives for deep drilling, all were in the bill but were not quantifiable and not subjuct to EIA analysis.

So, the answer is that what Congressman Waxman showed was accurate, that was directly from our study.

Mr. GREEN. That was based on the Conference Committee. And the Conference Committee, granted, didn't have an expansion of domestic production. Obviously, the Conference Committee didn't have ANWAR and didn't have any of the other potential in the Continental United States. So, I looked at that, and I agree, our Energy Bill didn't go far enough, at least from where I sat.

One month ago, the House approved our Refinery Revitalization Act to streamline permitting for mothballed refineries in economically depressed areas. Is that the best answer to increase refining capacity, or should we focus attention on expanding capacity at the existing refineries—I think I am following up a little bit on the chairman's report—as the market has been attempting to do in the last decade?

Mr. CARUSO. We have not made a specific study of H.R. 4517, but clearly I think our view is that we are going to need a substantial increase in refining capacity in this country over the next 10 to 20 years, and two of the most important things are providing the economic incentives, the return on investment, and the other one perhaps equally important is greater certainty. I think the most important thing for investors is to know what the rules and regulations are going to be, and I think that is the second aspect I would emphasize.

Mr. GREEN. Thank you. Mr. Holmstead, what is the Agency doing on the Agency level to clarify the New Source Review regulations in order to provide that certainty to both affected communities that I represent, but also refinery managers in these investments, and what could the EPA do more for that certainty?

Mr. HOLMSTEAD. We have taken two separate actions to really fundamentally clarify the New Source Review program to provide that certainty, and in a way that I think is particularly important for refineries. We have actually encouraged them to use something that we call "plantwide applicability limits," which basically says to the refinery, "you have a cap on the overall pollution in your facility, and within that cap you are free to manage it and to grow and to do it however you want." And in our experience, that is a very effective mechanism that we hope to be able to use, and there are people I think around the country beginning to take advantage of that.

Another reform that we had hoped to provide has to do with the replacement of equipment at refineries. We finalized that rule, but that rule is now being stayed by the D.C. Circuit.

Mr. GREEN. In my last 30 seconds, one refiner on the next panel will talk about complaints about novel interpretations of the New Source Review. Is the EPA trying to reach out to these manufacturers to help them through the process? Again, the certainty that Mr. Caruso talked about, if you have novel interpretations, it is really hard to quantify that, again, for the community, the investors or the managers.

Mr. HOLMSTEAD. I think there have been legitimate complaints about the New Source Review program, and a lot of the program

wasn't established in regulation. There have been guidance documents and different interpretations, and so for those issues for which there are literally thousands of pages of guidance documents, we have clarified them in regulation. We have been involved in addressing these issues for the last 2 years. And there are still some other reforms that we plan to do, having to do with such things as key bottlenecking changes at refineries. So, there will be additional reforms coming out in the future.

Mr. GREEN. Mr. Chairman, I appreciate that, and I hope maybe our subcommittee could look into that over a period of time, to see maybe if the chairman and I could understand it, maybe our petrochemical engineers could, too. Thank you.

Mr. HALL. Thank you, Mr. Green, for almost staying within your 5 minutes. Mr. Whitfield.

Mr. WHITFIELD. Thank you, Mr. Chairman.

Dr. Mark Cooper is going to be on the second panel, and in his testimony he made some reference to how "the domestic energy market has become concentrated in the hands of a few companies, particularly in certain geographical areas of the country." And he said that it "has become so concentrated that competitive market forces are weak, and the long-term strategic decisions by the industry about production capacity interact with short-term management of stocks to create a tight supply situation that provides ample opportunity to push prices up quickly." How many of you agree with that comment?

[Hands.]

Mr. Kovacic.

Mr. KOVACIC. From what we have seen in looking at literally dozens of transactions in the sector over the past 20 years and in conducting investigations that focus on conduct as well as doing empirical research, there is no question but that there may be specific instances in which firms unilaterally can make choices that affect the supply balance.

What we found generally is that those tend to be transient rather than long-standing, and as I read Mark's work, both his statement for today but also his earlier work, I think he dramatically underestimates the extent to which there are significant supply responses by individual market participants, market by market.

So, I would say that there are some instances in which the phenomenon he describes might come to pass, but I think he exaggerates the duration of those effects, and I think Mark's work does not account for what we see as being a significant degree of competitive dynamism market by market.

Mr. WHITFIELD. Mr. Wells, the GAO did a study on mergers and the impact. I have not read it, but you made some reference to it, and this is kind of tied in with what Dr. Cooper stated. What are your views?

Mr. WELLS. Clearly, the GAO study analysis in the various models that we built showed concentration numbers, measured exactly with the FTC and Department of Justice guidelines that were published in 1992, indicated that, I believe, in almost all 50 States there was an increase in market concentration, primarily statistically correlated to a reduction in the numbers of entries entering into the marketplace as well as the existing participants. The num-

bers would show that they went from moderately increased concentration to even highly concentrated. So, all the numbers statistically pointed to us that there was an increase that had an impact on prices.

Mr. WHITFIELD. Significant impact on prices?

Mr. WELLS. Prices of cents per gallon, yes, sir.

Mr. WHITFIELD. Cents per gallon.

Mr. WELLS. Yes, sir.

Mr. WHITFIELD. How many cents per gallon?

Mr. WELLS. It ranged from 1 to 7 cents per gallon. Again, we modeled this for the different types of gasoline and they had different geographic consequences on prices depending on the marketplace.

Mr. WHITFIELD. Now, the Federal Trade Commission disagreed with your methodology and findings, and what efforts did you all make to reconcile those differences, or did you make any efforts?

Mr. WELLS. Well, clearly this is the second exchange that I have had a chance to sit with my friend, Bill, next door to me, about the differences in methodology. We continue to believe an analytical sound methodology was used, and given the current state of economics, we welcome the opportunity to debate and discuss the merits of the methodologies that we used. I know there was some discussion about the major flaws in the GAO report. I don't want to take the time today, but we have answers to why we don't believe that there are flaws in the report. We have received requests from the FTC to consider holding a public conference. We welcome the opportunity to continue the debate and the dialog about methodology we used, but I think it is important for the committee and the members to understand that the FTC does their study and does their analysis a particular way, and they are looking at pre-merger approval, and they look at analysis involving each company's request for approval. The GAO study that was put together is a retrospect look where we go back in, long after the merger has taken place, and analyze a time period before the merger occurred and after the merger occurred. So, it is two different type of studies, and we look forward to and welcome the opportunity to work with the FTC, to understand the methodologies used, both what they use and what we use, but clearly our goal is to move the ball forward in terms of where do we go from here in the future in analyzing future requests for mergers.

Mr. WHITFIELD. Mr. Holmstead, do you have any thoughts on this at all?

Mr. HOLMSTEAD. No, I am not really qualified.

Mr. WHITFIELD. From what he is saying, the reformulated gas adds 4 to 8 cents a gallon, and he is saying mergers go anywhere from 1 cent to 7 cents a gallon. What about you, Mr. Caruso, do you have any thoughts on this?

Mr. CARUSO. We haven't done any specific analysis on that.

Mr. WHITFIELD. Do they have reformulated gas in Europe, or boutique fuels in Europe?

Mr. HOLMSTEAD. They certainly don't have reformulated gas. I am really not very familiar with their gasoline regulation.

Mr. WHITFIELD. What is the explanation of why fuel prices in Europe are $4 and $5, much more expensive than here. What is the reason?

Mr. HOLMSTEAD. I believe it is primarily tax policy. I think there are very high taxes on——

Mr. WHITFIELD. A lot more taxes there than here. Okay. Mr. Wells, there was some comment about your report, or did your report consider the effects on gasoline prices that State laws such as Minnesota's, which require a minimum markup on gasoline, may have? Did you all look at that at all?

Mr. WELLS. Could you repeat the question? The State of Minnesota?

Mr. WHITFIELD. Yes. It is my understanding that in Minnesota they require a minimum markup on gasoline. Are you familiar with that, or not?

Mr. WELLS. The analysis we use would be the prices that were posted at the wholesale level by the refineries, offered for sale, that the suppliers and distributors at the retail level would have paid, so that would have included that markup, if it was included at the wholesale level.

Mr. WHITFIELD. I will ask Mr. Caruso, do you consider that an appropriate analysis?

Mr. CARUSO. Again, we have not made a study of the GAO's work or the mergers themselves. We tend to defer to the FTC when it comes to anti-competitive analysis, or the Department of Justice for antitrust behavior.

Mr. WHITFIELD. Okay. Mr. Chairman, I will yield back the balance of my time.

Mr. HALL. I thank the gentleman. Mr. Dingell, the Chair recognizes you for 5 minutes.

Mr. DINGELL. Mr. Chairman, I thank you. This question is to Mr. Holmstead.

Mr. Holmstead, on June 22 of this year, I sent Administrator Leavitt a letter requesting whether any of the 200 or so refineries that have closed since 1980 are seeking permits from EPA or from the authorized States, that are necessary to reopen or to restart the refinery. This is, I think, a simple, straightforward request. EPA has failed to answer the letter. What is the answer to the question?

Mr. HOLMSTEAD. I just became aware of your letter this morning. I don't know the answer, but I can promise you that we will get it to you——

Mr. DINGELL. When will I get an answer?

Mr. HOLMSTEAD. I assume we can get it to you certainly within a week.

Mr. DINGELL. Are you, as you sit there, aware of any refineries that have been denied permits which would be necessary to reopen?

Mr. HOLMSTEAD. I am not aware of any closed refinery that has come in seeking a permit like that.

Mr. DINGELL. Mr. Chairman, I thank you very much. Thank you, sir.

Mr. HALL. Thank you, Mr. Dingell. The Chair recognizes Mr. Allen.

Mr. ALLEN. Thank you, Mr. Chairman. Mr. Holmstead, I would like you to address a statement made by Mr. Cavaney from API. It is in his written testimony, and he says, "For years, getting permission to build a new refinery or expand existing refineries in the United States has been an extremely difficult, inefficient, and inordinately time-consuming process." That is what he says.

Let us start with new refineries. In September 2000, Carol Browner was here, and she was asked how many permit applications had received to build new refineries. She said that EPA might have received one application in 25 years.

Mr. Holmstead, can you tell us how many permit applications to build new refineries that EPA has received since the year 2000?

Mr. HOLMSTEAD. As far as I know, there is one application for a new refinery. We are aware of one company that has come in seeking a permit for a new refinery. What is hard to know is how many other people have considered that and then decided to look elsewhere. That is the kind of information we just don't have.

Mr. ALLEN. And that one is in Arizona?

Mr. HOLMSTEAD. Yes.

Mr. ALLEN. As far as you know, is the application of the Arizona project on track?

Mr. HOLMSTEAD. I don't know. As you know, Mr. Allen, those permits are handled by the State, so I don't have any specific information about that.

Mr. ALLEN. Let me just ask you about permit applications for refinery expansion. In the year 2000, Administrator Browner testified that EPA had had 12 permit applications for expansions in the last 2 years. Of those, seven had been issued and five were pending with the expectation they would be wrapped up in a timely manner. She further testified that most permits for refinery expansions were issued within 12 months, and about half were issued within 5 months.

So, Mr. Holmstead, under the Bush Administration, is EPA granting refinery expansion permits in this same timely manner?

Mr. HOLMSTEAD. Again, most of those permits are actually granted by States. They have their own programs that are approved by EPA. I have no reason to believe that it is anything different from that. I do know that—and I think you mentioned this before, Mr. Allen—it is typically easier to expand an existing site than it is to get a new greenfield refinery just because there tends to be a lot of other issues besides Federal permits. There is the "Not in My Backyard" kinds of issues and a lot of opposition to a geenfield plant. So, I think typically it is easier to expand an existing refinery than it is to do a new one.

Mr. ALLEN. Thank you. A couple more questions just to follow up on Mr. Dingell's question. Several of us wrote a letter to you on May 13. You remember you appeared before the committee before, and when asked about a mercury provision, you indicated that it was not possible to perform an analysis—it would have been scientifically indefensible to perform an analysis recommended by your Clean Air Working Group.

Several of us, including Mr. Waxman, Ms. Schakowsky and I sent a letter to the EPA Administrator on May 13, and we asked a series of questions. We received a letter back, but it didn't an-

swer the questions. And then to follow, another separate set of letters was sent within a few days after that. I sent a letter—I am sorry—April 29 was the first letter, May 13 was the second letter. It has been over 2 months and we haven't received any answer to the questions raised in the May 13 answer. A non-responsive answer to the April 29 letter, no answer at all to the May 13 letter.

To repeat Mr. Dingell's question, when can we expect an answer from EPA?

Mr. HOLMSTEAD. Again, I am happy to answer any questions you may have today. On the substance as to where that letter exactly stands in our process, we get many, many letters, but I promise to go back and find out where that is, and we will get that to you as soon as we can.

Mr. ALLEN. Well, can I ask you for a commitment today that you will contact us tomorrow and give us a deadline for when you can get that material to us?

Mr. HOLMSTEAD. Yes. I can check where it is and we can call your office tomorrow and let you know when we can get that to you.

Mr. ALLEN. I would appreciate that. Thank you. Thank you, Mr. Chairman.

Mr. HALL. The gentleman's time has expired. Thank you for staying within the time.

The Chair will recognize Mr. Sullivan and ask Mr. Sullivan if he will yield to the ranking member for one question?

Mr. SULLIVAN. Yes, Mr. Chairman.

Mr. GREEN. Thank you, Mr. Chairman. To follow up my colleague from Maine, about the only one new refinery since 2000—and I know along the Houston ship channel where we have so many, there has been a great deal of effort to try and wring every gallon or every barrel you can out. Does EPA have access to the number of expansions of refineries around the country that would come in and ask for additional permitting, although I know it is done on the State level, but do you have access to that?

Mr. HOLMSTEAD. We wouldn't necessarily have access to that, and I am sorry, it has been something that we have tried to remedy in our system. Even though it is a Federal program, it is implemented by the States, so we don't routinely track applications for State permts. The reason I know about the one refinery is it is a pretty big deal and not many happen, so we know about that one. But in terms of individual permits that are sought for expansions, we don't have that number.

Mr. GREEN. Because we have increased capacity 7 percent even with a smaller number of refineries, so somehow we are wringing more gas out of a smaller number. Thank you.

Mr. HALL. Mr. Sullivan.

Mr. SULLIVAN. Thank you, Mr. Chairman. I have a question for Mr. Kovacic. In your testimony, you state "Lower inventory costs decrease the average cost of producing gasoline, to the benefit of consumers." Is that universally recognized as true?

Mr. KOVACIC. I think it is, Congressman. There has been a significant development, I would say, over the past decade or so, in the economic and business school literature, that emphasizes just-in-time inventory systems. The suggestion is that rather than mak-

ing major expenditures, capital and operational, to maintain stocks of goods, be it petroleum, be it clothing, be it manufacturing, if you can organize your system in a way that makes sure that what it is you need shows up at the time you need it, you can shrink your costs by reducing outlays for storage, and in this case, storage for gasoline. So, I would say the trend that we have seen across industries toward just-in-time techniques is a general affirmation of the principle that just-in-time systems and other mechanisms that reduce the cost of storing gasoline or other products tend to reduce costs.

Mr. SULLIVAN. Does that mean it is in the best interest of consumers for refiners to have lower inventories then, would you say?

Mr. KOVACIC. I think your question correctly points out that there can be a tradeoff here—that is, the reduction in inventories can limit the ability of the system, as a whole, to respond to specific disruptions. That is a cost of using these just-in-time systems. Our impression is that on the whole, looking across different markets and experiences, it has tended to reduce the cost of supplying gasoline, but I do know that in the hearings we held on price factors in 2001 and 2002, this tension was identified as a matter of concern. From our perspective, it is an issue that warrants our further attention. We would say, on the whole, the answer is "yes," but as your question suggests, it is something that is worth continuing attention because the adoption of these systems is a comparatively recent phenomenon in the sector.

Mr. SULLIVAN. Dr. Mark Cooper, who will testify on the next panel of witnesses, says that companies purposely do not hold inventories so that prices will increase. Do you agree?

Mr. KOVACIC. We don't. Again, it is so difficult to deal with the broadest generalizations and say "always" or "never," but I don't think we have identified systematic evidence that suggests that this is a pervasive pattern of behavior. From Mark's research and his work, if he identifies that, of course we would look at that.

In our Midwest gas study, which is perhaps the most detailed treatment of some possibilities for unilateral action to restrict output and raise prices, we did identify decisions by individual refiners to produce less rather than produce more. At the same time we found instances in which other refiners at the same time chose to produce more. So, while there might be individual episodes of that kind of behavior, we have not seen anything that suggests that it is a systematic pattern.

Mr. SULLIVAN. Mr. Chairman, one more question, if I could. Based upon the investigations of the FTC, in today's market, does competition encourage or discourage high inventory levels, and why?

Mr. KOVACIC. I would say the tendency is probably to discourage the maintenance of high inventory levels. Again, this is a consequence of years of recent experience, the kind of teaching that executives receive in business schools when they hear about inventory management, the general popularity of the just-in-time techniques all have tended to push companies in the direction more recently of holding fewer inventories. Our provisional assessment at the moment is that it is every much as likely that it reduces cost rather than increases vulnerability. But I wouldn't suggest that

larger question about the tension that may exist between cost reduction and possible instances of vulnerability arising from restricted flexibility to respond to specific disruptions is not a genuine issue. That remains a continuing matter of concern for us.

Mr. SULLIVAN. Thank you very much, I have no further questions.

Mr. HALL. The gentleman's time has expired. Mr. Issa would be recognized next. He was called to another committee. And, Mr. Holmstead, I am aware that you have a meeting at 1:15. We will try to release you as soon as we can.

Mr. Issa wanted these two questions asked. Which refiners have received waivers under the hardship provision of the Tier 2 sulfur program, and do any serve the New York Metropolitan Area?

Mr. HOLMSTEAD. I do have a list of the refineries that have received those hardship waivers. I have it here in front of me. I am not aware that any of them serve the New York City area. We have got two small refineries in Texas, two in Kansas, one in Wyoming, and one in Pennsylvania, and another one in Virginia. So, I would be happy to provide this for the record.

Mr. HALL. Would you mind submitting the list for us to give the Reporter?

Mr. HOLMSTEAD. I will do that.

Mr. HALL. And he said, what is the timeframe on a decision regarding New York's oxygenate waiver?

Mr. HOLMSTEAD. We are going through that information right now, and the Administrator has said publicly that we will do that as quickly as we can. We don't have a specific date at this point.

Mr. HALL. I will waive my further questions. Are there other questions of Mr. Holmstead?

Mr. ALLEN. Mr. Chairman, I would like to ask one additional question.

Mr. HALL. We will recognize you for one question.

Mr. ALLEN. Mr. Green was talking about expansion of existing refineries and New Source Review requirements. Department of Justice recently file a lawsuit, working with EPA, against a rural electric co-op. Would it be your opinion that New Source Review has been a discouragement to expansion of existing refineries?

Mr. HOLMSTEAD. I would say it is a fair criticism, that a lot of the uncertainty about how New Source Review works at existing plants has been a significant issue. We have tried to clarify that. Our rules are fairly clear, though, that unless a company takes what we call a "plantwide applicability limit," then they would have to go through New Source Review if they are expanding the plant in a way that would significantly increase emissions. So, what we are trying to do is make sure that we implement the law, but do it in a way that really does provide certainty. In that way, so a refinery, or any business owner, will know exactly what the rules are for them.

Mr. HALL. We're going to let Mr. Allen ask you one more question.

Mr. ALLEN. Thank you, Mr. Chairman, I will be quick. Going back to the topic we were discussing before, the letters I referred to dealt with EPA's refusal to perform part of the analysis that we think is required under the Clean Air Act.

Your mercury proposal under Section 112 would require only a roughly 29 percent reduction in mercury emissions by 2008, and this is based only on the use of technologies aimed at other pollutants, not mercury.

We have heard repeatedly in this committee and elsewhere that mercury-specific control technology such as activated carbon injection can, for example, that are in use in other industries, have been demonstrated on power plants, are being offered by vendors now, and, in fact, are under contract for installation now. So, two quick questions. Have you received any advice, written or oral, from the Office of General Counsel, on whether your refusal to analyze the use of activated carbon technology, or other technology, will harm EPA's ability to succeed in defending its mercury proposal, if it is finalized? And if you have received any such advice, can you tell us what the opinion of the Office of General Counsel attorneys has been?

Mr. HOLMSTEAD. As you can imagine, I am not at liberty to talk about legal advice that I have received from our General Counsel's office. What I can say is we have spent many, many hours meeting with vendors of technology, meeting with our experts, and meeting with experts at DOE. In all of our proposals, we have taken into account exactly where that technology stands.

You are correct in pointing out that ACI technology has been installed on some other types of plants, but they are plants that our experts tell us are very different from power plants. The kinds of demonstration projects that have been done are a few days at a full-scale plant, and what all of our experts tell us is that there are many technical hurdles still to be overcome.

We are optimistic that that technology will be available, as well as perhaps other technologies. In terms of something that could be installed on a number of power plants in the 2008 timeframe, however, we have not seen anything to suggest that that is possible.

Mr. ALLEN. I was under the impression that ACI was in place in a Southern Company plant.

Mr. HOLMSTEAD. There is an ongoing study at one Southern Company plant. My understanding is that has been on now for almost a year, but we have not seen the data from that study yet. I have heard anecdotal evidence that they have had some problems with it and they are still trying to evaluate the long-term prospects for that. But that is the only one that I am aware of, and we have not yet seen data from that study.

Mr. ALLEN. If your position is you can't give us the opinion, you can tell us whether or not you have received advice from the Office of General Counsel.

Mr. HOLMSTEAD. I can tell you that we have had extensive discussions with the Office of General Counsel, and there is nothing that they have told me to suggest that the way we have looked at this technology in any way would affect our opinion of how we would move forward with this rule.

Mr. ALLEN. Thank you, Mr. Chairman.

Mr. HALL. Thank you. Thank you, you have been a great panel. Thank you. We will dismiss this panel. We will have the second panel. Thank you very much, and those that back you up.

Mr. Edwards, we will recognize you, Senior Vice President, Supply, Trading and Wholesale Marketing, Valero Energy Corporation. Recognize you for 5 minutes, sir.

STATEMENTS OF GENE EDWARDS, SENIOR VICE PRESIDENT, SUPPLY, TRADING AND WHOLESALE MARKETING, VALERO ENERGY CORPORATION; ARJUN NARAYAMA MURTI, MANAGING DIRECTOR, GOLDMAN, SACHS & COMPANY; MARK COOPER, DIRECTOR OF RESEARCH, CONSUMER FEDERATION OF AMERICA; BOB SLAUGHTER, PRESIDENT, NATIONAL PETROCHEMICAL AND REFINERS ASSOCIATION; A. BLAKEMAN EARLY, ENVIRONMENTAL CONSULTANT, AMERICAN LUNG ASSOCIATION; RED CAVANEY, PRESIDENT, AMERICAN PETROLEUM INSTITUTE; ERIC SCHAEFFER, DIRECTOR, ENVIRONMENTAL INTEGRITY PROJECT; AND BILL DOUGLASS, CEO, DOUGLASS DISTRIBUTING

Mr. EDWARDS. Mr. Chairman, members of the subcommittee, thank you for this opportunity to testify regarding the issue of refining capacity and appropriate U.S. policy response.

Valero is a Fortune 500 independent petroleum refining and marketing company based in San Antonio, with over 20,000 employees. We have 14 North American refineries that process nearly 2.4 million barrels a day of crude in the production of premium, clean-burning fuels such as reformulated gasoline, CARB Phase II gasoline, and low-sulfur diesel.

Mr. Chairman, today Valero's refineries run above 95 percent utilization. Valero is doing everything we can do to meet consumers' growing demand for transportation fuel. However, such a high utilization rate leaves no reserve capacity for demand peaks or when refineries shut down for maintenance or stop production because of unscheduled outages.

Increasing supply is a top priority for Valero, and suggestions that merger activity within the refining sector hinder refinery expansion has not been the Valero experience. As a "pure play" refinery, Valero is in a good position to evaluate trends in the sector, our model stresses the expansion of our refining base, and seeks out the most economic crude in the marketplace.

Valero has experienced rapid growth since 1997, mostly by acquiring distressed refining assets and making substantial investments to enhance their capacity and improve environmental performance. There is no doubt that without Valero stepping in and buying some of these facilities, some would have shut down.

Our Texas City refinery is a good example of what we have done. Since acquiring the Texas City refinery in 1997, the company has increased the plant's total refining capacity from 165,000 barrels a day to 245,000 barrels a day, investing more than $750 million in the facility. In total since 1997, Valero has added more than 250,000 barrels a day of refining capacity through expansion projects throughout our system. At the same time, we have reduced emissions and produced cleaner burning fuels.

While our economies of scale have enabled us to increase supply, the Government sometimes creates an atmosphere of uncertainty that undermines such a course. We agree with the President's energy report that the Government needs to take steps to ensure

America has adequate refining capacity. The report calls for more regulatory certainty to refinery owners, and streamline the permitting process, where possible, to ensure that regulatory overlap is limited.

Unfortunately, what is too often overlooked is the fact that most environmental regulations today reduce supply, and to stay in business refineries must direct more of their capital to comply with environmental regulations, leaving less for expansion projects. For example, at Valero, from 2004 to 2005, we will spend $1.8 billion per year, of which $1.5 billion per year is related to turnaround, reliability, regulatory, and environmental projects, which only leaves about $300 million per year for strategic projects.

Tier 2 investments alone will cost us $1.7 billion over the 2002 through 2008 time period. And even with the good margins we are seeing today, this is consuming most of the cashflow from operations.

How do we fix the problems with refining? First, adopt energy legislation. The imbalance between refining capacity and demand did not emerge overnight, and won't be resolved quickly. Domestic refining industry finds itself in the same position as the domestic oil and gas producers of 20 years ago. Without proper attention to the role of the domestic refiner and shaping energy policy, you will see the Nation's dependence on imported petroleum products increase.

The current Administration and Congress are off on the right foot. The Conference Committee has concluded comprehensive energy legislation and the House has adopted the report. We only await Senate action on H.R. 6. H.R. 6 contains a carefully balanced fuel provision. While the removal of the 2 percent oxygen standard allows for more rational decisionmaking in the fuels market, the inclusion of a narrow safe harbor for MTBE liability provides much needed certainty to an industrial sector seeking to make capital investments in refinery expansions. By contrast, fuel additive liability suits quash innovation, depress capital, and deter new market entrants as the Council of Economic Advisors has reported.

Beyond passage of the energy bill, Valero also recommends the following policy action. Regulation should be assessed based on the cumulative impact. Desulfurization of diesel is a good example. Tier 2 diesel reductions are followed in rapid succession by off-road requirements, marine and rail fuel requirements. The cumulative impact is a challenging for supply.

Regulations should be reviewed based on the potential energy impact. Rules should not be changed in the middle of the game. The best example here is the 1999 error in interpretation of the New Source Review. The recently concluded EPA clarification rules should be implemented, and the EPA should develop an NSR rule to facilitate refinery debottlenecking as soon as possible.

Last, given the past history of low return on investment, the Government should consider giving the refineries' favorable tax treatment for investments made to comply with environmental standards. As EAI data shows, refineries' return on investment from 1980 to 2002 generally range from zero to 10 percent and averaged about 5 percent. Congress should consider, or could consider, some combination of tax credits for environmental compli-

ance or an enhanced depreciation for such investment. This is needed to counterbalance the fact that foreign refineries do not have to invest in environmental regulation to the degree that the U.S. does.

Thank you much for this opportunity to testify, and I look forward to your questions.

[The prepared statement of Gene Edwards follows:]

PREPARED STATEMENT OF GENE EDWARDS, SENIOR VICE PRESIDENT OF SUPPLY, TRADING AND WHOLESALE MARKETING, VALERO ENERGY CORPORATION

Chairman Hall, Congressman Boucher, and Members of the Subcommittee, thank you for this opportunity to testify regarding the issue of refining capacity and appropriate U.S. policy response. My name is Gene Edwards, and I am Senior Vice President of Supply, Trading and Wholesale Marketing at Valero Energy Corporation.

Valero is a Fortune 500 company based in San Antonio, with over 20,000 employees that has experienced significant growth since 1997. One of the top U.S. refining companies, Valero has an extensive refining system with a throughput capacity of more than 2.4 million barrels per day. The company's geographically diverse refining network stretches from Canada to the U.S. Gulf Coast and West Coast to the Caribbean. Valero is recognized throughout the industry as a leader in the production of premium, clean-burning fuels such as reformulated gasoline, CARB Phase II gasoline, low-sulfur diesel and oxygenates. A marketing leader, Valero has approximately 4,500 retail sites branded as Valero, Diamond Shamrock, Ultramar, Beacon and Total. The company markets on a retail and wholesale basis through a bulk and rack marketing network in 40 U.S. states, Canada, Latin America and the Caribbean region.

Valero is proud of its record of environmental achievement, which goes beyond its commitment to produce cleaner-burning fuels and additives. Investing millions of dollars in pollution prevention and waste minimization, Valero was the first petroleum refiner ever to receive the prestigious Texas Governor's Award for Environmental Excellence and was recognized during the Clean Air Celebration for its "outstanding environmental stewardship and leadership."

CURRENT STATE OF THE REFINING INDUSTRY

The United States has long recognized the importance of domestic refining to its economy. Many people in various states across the country have found high-paying jobs in the refining sector, and the energy sector plays a vital role in the gross domestic product of the U.S.

One factor determining the current supply/demand balance is the lack of new U.S. refinery capacity relative to demand. According to the Bush Administration's National Energy Policy (NEP), released in May 2001,

> During the last ten years, overall refining capacity grew by about 1 to 2 percent a year as a result of expansion in the capacity of existing, larger refineries. Although there was significant, sustained improvement in margins during 2000, those gains arose out of a very tight supply situation and high volatile prices. Industry consolidation has been a key response to this poor profitability. (May 17, 2001 at 7-13)

Today refineries run at about 95 percent utilization, as compared to other industries' utilization rates of around 82 percent. Such a high rate leaves little reserve capacity that can be used when demand peaks or another source of supply shuts down. Thus, when refineries close for maintenance or stop production because of accidents, supplies tighten, with predictable price implications. This is particularly true in states like California, where the supply of gasoline is often extremely tight. As a spokesman for the Western States Petroleum Association put it, "Refineries need to produce at nearly full capacity to match the demand of a large state that puts an emphasis on gasoline and other petroleum products." (Desert Sun, April 4, 2004)

Some have suggested that a logical way to address the supply issue is to build more or expand existing refineries. But, companies can no longer build new refineries due to the great expense of permitting and the near-impossibility of finding a building site. No new refinery has been built in the United States since 1976. In California, the state hit hardest by high gasoline prices, no new refinery has been built since 1969. (Houston Chronicle, March 27, 2004)

THE VALERO EXPERIENCE

Mr. Chairman, some have suggested that merger activity within the refining sector complicates the picture for expanding refining capacity. This has definitely not been the Valero experience. As a "pure play" refiner, Valero is in a good position to evaluate trends in the sector; our model stresses the expansion of our refining base, and seeks out the most economical crude in the marketplace. Being an independent refiner, we do not engage in oil and gas exploration and development, and while marketing of gasoline is important to Valero, it only represents about 10 percent of the Corporation's assets.

Valero has experienced rapid growth since 1997, mostly by acquiring at-times undervalued refining assets and making investments in those refineries to enhance their capacity and improve environmental performance. Our Texas City refinery is a good example. Since acquiring the Valero Texas City refinery in 1997, the company has added 73 jobs at the refinery, which today employs 477 individuals. Valero has also increased the plant's total refining capacity from 165,000 barrels per day (BPD) to 243,000 BPD, investing more than $750 million in the facility. The refinery has also gained recognition as one of the nation's safest work sites after being one of the first nine U.S. refineries to be accepted into the Occupational Safety and Health Association's (OSHA) Voluntary Protection Program as a Star Site.

Similarly, when Valero recently announced the acquisition of the former Orion facility outside of New Orleans, Louisiana, we identified approximately $25 million in expansion and upgrade opportunities that will enable the refinery to process additional heavy feedstocks, increase throughput capacity, upgrade its product yields and improve on-stream reliability. Our experience with other facilities has been similar: acquisitions have allowed realization of economies of scale, resulting in increased capacity.

THE GOVERNMENT'S ROLE IN ADDRESSING CAPACITY CONCERNS

Clearly, as a general matter, capacity utilization in the refining sector is quite high. Valero has been able to make capacity expansions and upgrade at various facilities. However, the government can and does sometimes create an atmosphere of uncertainty that undermines the realization of the goal of rationalizing refining capacity. Responding to this problem, the National Energy Policy Development Group (NEPD) recommended that the government "take steps to ensure America has adequate refining capacity to meet the needs of consumers." This would include providing "more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited." (NEPD at 10)

Unfortunately, the one thing that all of the new environmental regulations have in common is that they reduce supply. And, to make matters worse, refiners must direct much of their capital investments to meet environmental regulations so there is less capital available for much-needed expansion projects. In fact, increasingly stringent environmental regulations, often adopted in piecemeal fashion, have created operational constraints and have sharply curtailed the flexibility of refiners to expand. Over the course of the last decade, the National Petroleum Council estimated that total investments to comply with the Clean Air Act Amendments in the refining sector exceeded the total book value of the refineries brought into compliance by $6 billion dollars. Things are even worse today. Refiners face near simultaneous implementation of reductions in gasoline sulfur and air toxic constituents, changes to diesel fuel to reduce sulfur to ultra-low levels, and, perhaps, limitations on the use of clean-fuel additives like MTBE. At the same time, the U.S. Environmental Protection Agency has made it increasingly difficult for refiners to expand capacity based upon novel and restrictive interpretations of the New Source Review (NSR) program.

The Tier II diesel standards may prove particularly challenging. The program is being implemented in a way that is going to cause some logistical issues and high price volatility. On-road diesel sulfur specifications go to 15 ppm by June 2006. Off-road diesel sulfur specifications go from 2000 ppm to 500 ppm by mid-2007, and to 15 ppm in 2010. Home heating oil remains unchanged at 2000 ppm. Railroads and Marine fuels will go to 15 ppm in 2012. Rather than create all the grade segregations, the EPA should have had an overall distillate pool sulfur that ramps down over time. The current program will result in a balkanized diesel fuel market that mirrors some of the difficulties discussed in the context of so-called boutique gasolines.

The conditions that have caused our current stretched capacity in refining are not likely to resolve themselves in the near future without careful planning and a balanced energy policy that takes refining issues into account. During the summer driving season, refiners struggle to make up inventory deficits created by the need

to produce more home heating oil this past winter. Also, unusually high natural gas prices last winter directed natural gas into direct usage and away from feedstock usage. As a result, less MTBE and alkylate were made, thus further depriving the summer driving season of some of its usual cushion in gasoline inventories. The tight market for MTBE is already fueling predictions of another summer of high gasoline prices.

And, of course, as state actions and market forces result in MTBE phase-outs, further stress is placed on supply. DOE's Office of Policy and the Oak Ridge National Laboratory specifically found that an MTBE ban is equivalent to a loss of 300,000 barrels per day of premium blendstock.

Federal energy legislation contains an ethanol mandate, part of a carefully balanced fuels package. However, the existence of this mandate is not a mechanism likely to address supply concerns. An ethanol mandate actually will make it harder for refiners to provide cleaner fuels to consumers at acceptable prices. Due to ethanol's high blending vapor pressure, pentanes are backed out of the gasoline pool, further decreasing supply. An ethanol mandate will hinder refiners' ability to optimize the quality and volume of cleaner-burning gasoline. This will increase refining costs, and negatively impact both gasoline supplies and price. According to the California Energy Commission, the costs of substituting ethanol-blended gasoline in that state could increase refining costs by up to 7 cents per gallon. Based on our review at the Valero Benicia Refinery, an MTBE ban, coupled with ethanol blending reduces production volume by 8%.

HOW DO WE FIX THE PROBLEM WITH REFINING? ADOPT ENERGY LEGISLATION.

Suffice it to say, the imbalance between refining capacity, supply and demand did not emerge overnight, and it won't be solved overnight. The domestic refining industry finds itself in the same position as the domestic oil and gas producers of twenty years ago. Without proper attention to the role of the domestic refiner in shaping energy policy, you will see the nation's dependence on imported petroleum products increase. The current Administration and the Congress are off on the right foot: a Conference Committee has concluded comprehensive energy legislation and the House has adopted the report. We await only final Senate action on H.R. 6.

H.R. 6 contains a carefully balanced fuels provision. While the removal of the two-percent oxygen standard allows for more rational decision-making in the fuels market, the inclusion of a "safe harbor" for MTBE liability provides much needed certainty to an industrial sector seeking to make capital investments in refinery expansions. There can be no doubt that taking punitive action against refiners for meeting a government standard through use of a government-approved product is not only unfair, but makes the capacity situation even worse. A refiner's ability to address supply concerns is directly related to the refiner's ability to utilize capital, develop new fuels, and help maintain a competitive marketplace. By contrast, fuel-additive liability suits quash innovation, depress capital, and deter new market entrants.

Not only is the tort system extraordinarily costly, but without some stability in liability risk, powerful disincentives have been created to continued manufacturing of additives. According the Council of Economic Advisors (CEA), "At higher levels of expected liability costs, . . . firms will choose to forgo innovation or to withhold a product from market, resulting in a net negative effect of expected liability costs on innovation." (April 2002 report)

There can be little doubt that as our economy expands and our population grows, the need for innovation in fuels will increase as well. Under such circumstance, the adoption of the narrow liability protections in H.R. 6 becomes a critical piece of the puzzle in addressing refinery issues. Distinguished University of Texas Business and Engineering Professor Margaret Maxey wrote, "Litigation is out of control, and the situation will deteriorate further if Congress fails to give makers of the fuel additive MTBE liability protection in lawsuits involving leaking fuel tanks. The priority should be to make reforms that put a cap on present and future costs, not only to safeguard the development of clean-fuel additives, but to encourage innovation generally. Without some restraints in today's climate of infectious litigation, powerful disincentives will inhibit the continued manufacture of products where technology itself is at risk." (Houston Chronicle, Nov. 18, 2003).

Beyond currently pending energy legislation, there are several additional concrete steps that could be taken to address refining issues:

- **Address the cumulative impact of regulations.** There is a tendency to view each regulation imposed upon refining in a vacuum, particularly when measuring primary and secondary economic impacts. However, as we observed above, the plain fact is that the refining sector has numerous, overlapping regulations. Most recently, compliance deadlines have come one on top of another. When

EPA, DOE and the Office of Management and Budget conducts their reviews of each regulation, the cumulative impact of regulations on the supply, distribution, and cost on transportation fuels should be fully considered before taking action.

- **Ensure thorough review of regulations.** Preparation of an Energy Impact Statement for major rules could help ensure that energy supply impacts are fully understood and balanced with environmental goals. Proper use of cost-benefit analysis to ensure cost-effectiveness of regulations is another essential tool.
- **Do not change the rules in the middle of the game.** Retroactive reinterpretation of regulatory programs such as EPA's NSR enforcement activities constitute rulemaking without due process and opportunity for comment. Also, changes in requirements that negate good faith compliance investments waste scarce capital resources that are much needed for other projects such as refining capacity expansions. To deter unwise government intervention, Congress should also consider enacting measures which compensate impacted parties when the reversal of federal rule or regulations strand business with useless equipment which was built specifically to comply with federal law.
- **Reform the permitting and New Source Review processes in order to facilitate capacity expansion and maintenance.** By questioning state permitting decisions and policy over the past 20 years, EPA will only further slow down the permitting process and divert state resources towards reviewing past decisions. Fortunately, the U.S. EPA has now finalized two sets of rules dealing with NSR: one suite of reforms addressing many refining needs; another addressing equipment replacement. The refining sector awaits promulgation of a de-bottlenecking rule that can further assist in enhancing refining capacity. Implementation of these rules are critical at this time as state permitting authorities and refiners work together to expedite the permitting processes for important upcoming environmental regulations, such as the Tier II gasoline sulfur reduction requirements. In short, NSR should apply only if emissions actually increase significantly. Any interpretation that would result in perpetual exposure to NSR cannot be defended; and
- **Consider tax incentives to encourage environmental improvements.** The costs associated with environmental compliance often make the difference between a competitive refinery operating in the U.S., and one that closes. Valero alone spends on the order of $100 million per year in environmental compliance expenditures. The real cost of these environmental standards is lost international competitiveness for U.S. refiners. The Office of Technology Assessment has found that the cost to the domestic refining industry for pollution abatement is substantial and is higher than for most other industries. API has calculated that petroleum refining could account for a disproportionate 17% of the national environmental expenditure in the year 2000. Given the typically low return on capital investment (ROI) in the refining section, such tax treatment is justified. Data from the Energy Information Administration shows EIA shows that US Refining/Marketing ROI from 1980 to 2002 generally ranges from 0% to 10% and looks to average about 5%. Although by no means a complete solution, the Congress could consider some combination of tax credits for environmental compliance or enhanced depreciation for such investments.

CONCLUSION

While these responses to current refining difficulties are by no means comprehensive, they represent a start. President Bush recently remarked that, "the solution for our energy shortage requires long-term thinking and a plan that we'll implement that will take time to bring to fruition." At Valero, we couldn't agree more. However, any plan, in order to succeed in providing the American consumer with reliable and affordable motor fuel supplies, must take into account the current state of the US refining industry and of our product distribution infrastructure.

Thank you very much for this opportunity to testify.

Mr. HALL. Thank you very much.

Mr. Arjun Murti, the Chair recognizes you for your opening statement, sir.

STATEMENT OF ARJUN NARAYANA MURTI

Mr. MURTI. Thank you, Mr. Chairman and members of the subcommittee, for this opportunity to testify before you today about the issues surrounding the U.S. refining industry. My name is

Arjun Murti, I am the Managing Director at Goldman, Sachs, where I am a Senior Equity Investment Analyst covering the integrated oil, refining and marketing, and exploration and production sectors.

If steps are not taken to add new energy infrastructure or reduce demand, this country appears headed for its next big energy crisis like we saw in the late 1970's, a period of much higher and more volatile prices, which is a situation made worse by the ongoing geopolitical turmoil in key oil-exporting countries.

We think the probabilities are significantly higher that at some point this decade, this country is more likely to see $60-$80 oil and $2.50-$3 a gallon gasoline than it is to revert back to the nice $15-$25 oil and the $1-$1.25 gallon gasoline we have had for most of the 1980's and 1990's.

Economic growth, especially in the United States and China, is straining the limits of existing global refining capacity as demand growth has basically eaten through all the spare capacity we have not just in refining, but in global crude oil availability, in OPEC utilization, as well as U.S. natural gas supply that was built up during the energy investment boom period of the 1970's. We basically need to add supply or reduce demand.

On the demand side, however, history unfortunately suggests demand adjustments will only occur after a crisis, not before. For example, from 1980 to 1983, we did have decline in oil demand for 4 years both in the U.S. and globally, but it took long gas lines, an Arab oil embargo, and a deep recession, not to mention a crude oil spike to $80 a barrel in real terms in 1979, before consumers changed their behavior.

Since you basically can only run your car on gasoline and can't switch to another fuel, and given consumer preferences for large, powerful, comfortable, but unfortunately gas-guzzling SUVs, we think oil demand is essentially not elastic relative to the price. We think it would be logical for the U.S. Government to consider proactively implementing policies that encourage a reduction in the long-term growth of oil demand such as disincentivizing the use of sport utility vehicles by the mass population. But given that that is probably not such a popular step, we are going to have to turn to the supply side.

When you look at supply, we think significant amounts of new refining capacity will be needed, though this is also likely to be a long-term proposition because of inadequate historical profitability in the refining sector. In the 1990's, the return on capital averaged just 6.5 percent, which is highly inadequate to stimulate investment. You have also got things like environmental permitting and "Not In My Back Yard" concerns. I would say that is secondary, though, to the profitability question.

Our supply/demand analysis shows that the United States will need to add the equivalent of a new 260,000 barrel a day refinery every other year, starting in 2 years, in order to meet trend oil demand growth, and we have accounted for 150,000 barrels of ongoing debottlenecking. We think the earliest this country might see a new refinery is 2014, which is essentially a way of saying "not anytime soon."

Now, three things we think are needed to ensure new refinery capacity is added. First and foremost, refining margins and U.S. gasoline prices need to be a lot higher than they have in the past in order to provide adequate returns on capital for the refining sector. Poor historic returns in refining have incentivized both oil companies and investors to invest in other sectors. There has been a lot of investment in the technology sector, not surprising—Microsoft, Intel, Dell—hugely better profitability than any oil company. Companies invested in health care, not surprising—Merck, Pfizer, Bristol-Meyers—significantly better profitability than the energy sector. The refining sector has had one of the worst returns on capital of any economic sector within the U.S. industry. Companies and investors also need to have confidence that windfall profit taxes will not be reintroduced, which would detract from confidence in the profits and returns that could be earned.

The second big thing we need is stability in the four key crude oil exporting countries—Saudi Arabia, Iraq, Venezuela, and Iran. This is important because our refineries use 10 million barrels a day of imported crude oil, and if there are disruptions where the crude is not available, you are not going to be able to run your refineries and you won't get gasoline.

Essentially, we think new Government institutions that are representative of the underlying population and a proactive growth are needed in those countries.

The last point is about streamlining environmental permitting and NIMBY issues. You are not going to have a lot of permits until people first have confidence that the returns on capital are good enough to justify investment.

Today, we believe investors will react unfavorably to an announcement by any of the major oil companies or independent refiners to announcing a new-build refinery in the U.S. Even if funding were available—and they could probably get the funding—the likely negative stock price reactions, in our view, would keep company management from pursuing refinery new-builds in the current investment climate.

Mr. Chairman and members of the committee, I thank you for the opportunity to testify, and would welcome any questions at the right time.

[The prepared statement of Arjun N. Murti follows:]

PREPARED STATEMENT OF ARJUN N. MURTI, MANAGING DIRECTOR, GOLDMAN, SACHS & CO.

Mr. Chairman and Members of the Subcommittee, thank you for the opportunity to testify before you today about the short-term and long-term issues surrounding the US refining industry.

My name is Arjun Murti. I am a Managing Director of Goldman Sachs, where I am the Senior Equity Research Analyst covering the integrated oil, refining & marketing, and exploration & production sectors. The views presented here today are my own and do not necessarily reflect the view of Goldman, Sachs & Co.

ENERGY SUPPLY INCLUDING US REFINING CAPACITY IS RUNNING ON EMPTY

Spare US refining capacity, global crude oil availability, and US natural gas supply have steadily eroded over the past 20 years, owing to growing demand and inadequate investment (see Exhibit 1). As such, consumers and businesses should expect higher and more volatile energy prices in the future, until adequate new infrastructure is built. Both price volatility and overall price levels are further increased by ongoing geopolitical turmoil in key oil exporting countries. Note, we do not believe

the world is running out of oil so to speak, rather we see this as a lack of adequate investment.

Growing energy demand has naturally occurred as global economic growth has been robust, especially in the US and Asia. China is now the second largest oil consumer after the US in absolute terms, with oil import growth rising dramatically in recent years and forecast to rise inexorably into the future (see Exhibit 2). It is noteworthy that the two largest demand centers (the US and China) are on opposite sides of the world, with most of the remaining oil resource "in the middle" in the Middle East and Russia.

Energy demand growth over the past 20 years has been met by the steady "exploitation" of the large investments made during the last energy boom period in the 1970s. Global refining capacity expanded significantly during the 1970s and early 1980s, but has since grown at a pace well below oil demand (see Exhibit 3). After 20 years of living off of cheap energy, spare capacity throughout the energy industry is greatly diminished.

STATE OF US REFINING INDUSTRY LINKED TO CRUDE OIL IMPORT MARKETS

Total US consumption of refined oil products (i.e., gasoline, diesel, jet fuel, heating oil, residual fuel oil) is 15.6 mln b/d. Domestic refining supply is 14.3 mln b/d and we import 1.2 mln b/d of refined products. However, in order for our refineries to run at utilization rates in excess of 90%, we currently import roughly 10 mln b/d of crude oil with only 5.6 mln b/d coming from domestic crude sources (see Exhibit 4).

Given the substantial US crude oil import needs, the state of the US refining industry is closely linked to the state of crude oil import markets. If a disruption occurs that limits crude oil imports, refinery utilization by necessity will fall, or at least once local crude oil inventories are depleted. As such, any steps taken to expand the US refining industry has to be consistent with policies that ensure adequate crude oil imports. Given that this testimony is focused on the refining industry, we have chosen not to expand on the state of crude oil markets. For more details, please refer to other published research by Goldman Sachs, including our June 8, 2004 report, "The sustainability of higher oil prices: Revenge of the old economy, Part II."

Going forward, we estimate that refined product demand will grow 1.6% per year, or about 260,000 b/d per year, over the remainder of this decade. The estimate reflects expected trend oil demand growth relative to expected trend GDP growth forecast by Goldman Sachs economists. In our view, continued debottlenecking in refining capacity is likely, but will be insufficient to meet desired demand growth, resulting in increased refined product imports (i.e., gasoline, diesel, jet fuel, heating oil, and residual fuel oil) in the absence of steps taken to further accelerate domestic capacity gains (see Exhibit 5). If natural debottlenecking slows, as some are forecasting, refined product imports will need to increase at an even faster rate in order for desired demand growth to be satisfied.

If US refining capacity does not grow in the future, crude oil import growth would be limited to offsetting the rate of decline in domestic supply, which we estimate to be around 3% per year. However, if the US economy continues to grow, resulting increases in oil consumption would need to be met by growing refined product imports. Either way, US imports of crude oil plus refined products will need to grow in the future, essentially at the rate of oil consumption growth plus the decline in domestic crude oil supply.

GROWING US DEPENDENCY ON OIL IMPORTS INEVITABLE: LACK OF SPARE CAPACITY RAISES OUR VULNERABILITY TO DISRUPTION

Geologically the US is very mature, with an inadequate amount of remaining oil reserves to meet a perpetually growing economy. As such, rising US dependency on oil imports is inevitable. Oil import dependency is not inherently a problem, but is a greater challenge today given three new developments:

1. *Geopolitical turmoil.* Rapid population growth, the lack of a diversified and growing economic base, and the lack of representative governments has increased geopolitical turmoil in four key oil exporting countries—Saudi Arabia, Iraq, Venezuela, and Iran. As such, the risk of a supply disruption is at the highest levels seen since the oil embargo years of the 1970s. Geopolitical and economic stability is needed in these key oil exporting countries before the risk premium in oil prices will likely subside. Stability likely involves the establishment of new government institutions in these countries that are representative of the underlying population and that are pro-economic growth. Supporting partnerships between western oil

companies and host governments in these key oil exporting countries to develop the country's resources would also be helpful.

2. *China*. China has emerged as the second largest oil consumer in the world (after the US), with a rapidly growing thirst for oil imports given its own inadequate resource base. Aside from competing with the US over energy supply, the challenge is compounded by the fact that China is on the opposite side of the world as the US and shipping capacity is also in tight supply.

3. No spare capacity. Spare capacity in crude oil, shipping, and refining markets is essentially gone.

In an environment where (1) spare crude oil capacity is minimal, (2) the US is dependent on oil imports, and (3) key oil exporting countries are facing a high amount of geopolitical turmoil, US consumers and businesses should be prepared for energy prices that are higher in absolute terms and more volatile than the levels seen during the 1980s and 1990s.

DOMESTIC REFINING CAPACITY GROWTH PREFERABLE TO GROWING REFINED PRODUCT IMPORTS

In our view, there are a number of reasons why policies that encourage growth in domestic refining capacity and imports of crude oil are preferable over growth in imports of refined products.

Over time, foreign refining capacity, like US refining capacity, will be increasingly dependent on crude oil imports from geopolitically-challenged countries. By importing refined products, the US then becomes subject to two sources of disruption: first at the crude oil exporting country and then again potentially at the refined product exporting country.

A recent example of this issue is Venezuela, where a national protest strike in early 2003 disrupted both crude oil and gasoline exports from Venezuela to the US as well as crude oil exports to Caribbean refineries that in turn export finished gasoline to the US. Since the strike officially ended, crude oil supply from Venezuela has not fully recovered to pre-strike levels, and gasoline exports to the US (which meet our strict environmental standards) also remain well below pre-strike levels due to ongoing post-strike operational issues at Venezuelan refineries (see Exhibit 6).

From an environmental perspective, US environmental standards tend to be consistent with western European countries, but significantly stricter than most of the rest of the world. The benefits of the stricter environmental standards should be obvious to anyone that travels to cities elsewhere in the world that have lower standards. There is no guarantee that foreign refineries will make the necessary investments to comply with US environmental standards. As such, the US could face the choice (actually, in the not too distant future), where it has to choose between limiting refined product imports and accepting the consequences of $3 per gallon gasoline prices or weakening environmental standards (or both).

Other benefits of growing domestic refining capacity include the fact that the cost of importing crude oil is less than the cost of importing refined products, given the need for a margin in order to refine crude oil into usable end products. Finally, a growing US refining industry will result in increased manufacturing and construction sector employment in the US.

HIGHER RETURNS ON CAPITAL NEEDED TO STIMULATE ADEQUATE US REFINING CAPACITY GROWTH

In order to stimulate growth in domestic refining capacity, we believe refining margins will need to be significantly higher than historic levels. Returns on capital employed (ROCE) in the US refining industry were poor during most of the past 10 years (see Exhibit 7). This is primarily because refining margins, which are the spread between refined product selling prices (i.e., the price of gasoline, diesel, jet fuel, heating oil, and residual fuel oil) and the cost of crude oil, have been low.

Low refining margins were caused by the significant excess capacity that existed during most of the 1980s and 1990s following the investment boom period of the 1970s. With low refining margins and returns on capital, refining capacity growth has been essentially stagnant save some amount of debottlenecking that naturally occurs every year.

With low returns on capital, it should not be surprising that capital investment in US refining capacity has been at very low levels (see Exhibit 8). We are forecasting an increase in capital spending in 2004-2006, but this is almost entirely driven by the need to meet new environmental regulations for gasoline and diesel in the US.

AT $30-$80 PER BBL CRUDE OIL, $1.80-$3.00 PER GALLON GASOLINE PRICES NEEDED

We estimate that it would cost between $2 to $3 billion to build just one new 260,000 b/d refinery in the US. Note, we forecast US refined product demand growth will be around 260,000 b/d per year for the foreseeable future. The lead time to start-up is estimated at around 3 years after all environmental and other approvals have been attained. Including likely permitting and NIMBY delays, we believe the earliest this country will likely see a new refinery is 2014, if not longer. Government steps to streamline and expedite environmental permitting and construction approval processes perhaps in certain "industrial zones" that would not face NIMBY issues, in our view, would accelerate the development of new refining capacity.

In order to generate an acceptable minimum after-tax internal rate of return of 10%, we estimate that over the next 25 years Gulf Coast 3:2:1 refining margins (widely considered to be the US benchmark refining margin) would need to average around $7.75 per bbl at the $2 billion new build refinery cost and $9.50 per bbl at the $3 billion construction cost (see Exhibit 9). This compares with the 1990-2000 average Gulf Coast 3:2:1 refining margin of $3.18 per bbl.

Translating the required refining margin into an average US gasoline selling price at the pump requires three additional assumptions: the price of crude oil, the so-called marketing margin (i.e., the spread between the gasoline selling price at the pump and the price paid to the refinery), and federal and state government taxes. If we assume $30 per bbl for the price of West Texas Intermediate (WTI) crude oil (the US benchmark crude oil price), the average marketing margin experienced over the past 10 years, and no change to government taxes, we estimate the average gasoline selling price in the US will need to be around $1.80 per gallon at the $2 billion new refinery construction cost and $1.95 per gallon at the $3 billion construction cost. This compares with the 1990-2000 average US gasoline selling price at the pump of $1.15 per gallon.

If we assume $50 per bbl for WTI oil and no changes to our marketing margin or tax assumptions, the average gasoline pump price would need to be $2.05 per gallon at the $2 billion refinery construction cost and $2.25 per gallon at the $3 billion construction cost.

Finally, assuming an $80 per bbl WTI crude oil price and making no change to our marketing margin or tax assumptions, the average gasoline pump price would need to be $2.70 per gallon at the $2 billion refinery construction cost and $3.00 per gallon at the $3 billion construction cost.

We note that in real terms (i.e., in 2003 US dollars), WTI oil prices remained between $50-$80 per bbl from 1979-1984, including averaging a full-year above $80 per bbl (see Exhibit 10). Over the remainder of this decade, we believe the probability of moving to a $50-$80 per bbl price band is significantly higher than the chances of reverting back to a $15-$25 per bbl band. As such, irrespective of whether we add new refining capacity, US consumers and businesses should be prepared to pay a lot more for energy than they did during the 1980s and 1990s. The price paid, however, will be higher, if domestic refining capacity does not grow.

POOR HISTORIC RETURNS SUGGESTS INDUSTRY WILL BE CAUTIOUS BEFORE ADDING NEW CAPACITY

Given the poor health of the US refining industry for most of the past two decades, refining margins will likely need to be well in excess of so-called replacement cost levels before companies move to add new grassroots refining capacity. Such caution will likely be evident, even if rules are changed to streamline environmental and project approval processes and NIMBY concerns do not materialize. As a result, we believe the government should resist the temptation to implement "windfall profits" taxes should oil prices move materially higher from current levels, as such taxes would further disincentivize capacity growth and contribute to investor skepticism over investing in the oil and refining sector.

We believe investors would react unfavorably to an announcement by any of the major integrated oil (e.g., Exxon Mobil, ChevronTexaco, ConocoPhillips, BP, Royal Dutch/Shell) or independent refining companies (e.g., Valero Energy, Marathon Oil, Sunoco, Premcor, Tesoro Petroleum, Amerada Hess, Frontier Oil) to build a new refinery in the US.

In an era of low interest rates, healthy corporate balance sheets, and capital availability, financing would likely not be an issue for at least the first few refineries proposed. However, the likely negative stock price reactions, in our view, would keep oil company managements from pursuing refinery new builds in the current investment climate.

CAN THE US LOWER ITS GROWTH RATE IN OIL DEMAND WITHOUT NEEDING A MAJOR CRISIS?

In addition to understanding supply-side adjustments and required price levels to stimulate sufficient supply growth, we believe demand-side adjustments should also be pursued, preferably proactively rather than reactively. History, unfortunately, suggests that demand-side adjustments will occur only after a crisis, not before.

We note that the last major effort made to improve fuel economy and overall energy efficiency was in the 1980s following the energy crisis years in the 1970s. In response to the $80 per bbl (in 2003 US dollars) oil price spike in 1979, oil demand growth actually fell for the four years from 1980-1983 (see Exhibit 11). In addition to very high energy prices, economic growth was weak and unemployment and interest rates high during this period.

The lack of fuel switching options for transportation fuels and consumer preferences for large, powerful, and comfortable vehicles are the key reasons oil demand price elasticity is low, in our view. Very simply, most Americans would rather own a large, gas-guzzling SUV and pay more for gasoline than an embarrassingly cramped but fuel-efficient Mini. To change that behavior in the absence of government policies in the 1970s required the inconvenience of gas lines and a super spike in oil prices that truly took a large chunk of change out of consumer wallets and pocketbooks. We do not believe it is in anyone's interest to wait for crisis conditions to again emerge to stimulate a new round of conservation measures. However, that is the path upon which we appear to be headed.

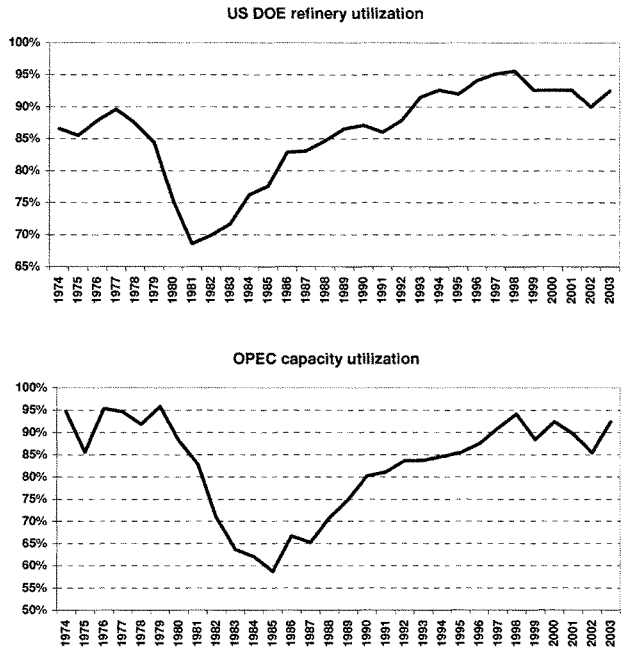
In our view, it would be logical for the US government to proactively implement policies that encourage a reduction in the growth rate of oil demand. We note that the cost of waiting will likely result in much greater economic damage over the long term than the short-term inconvenience of no longer being able to buy an inexpensive SUV as an example.

Examples of logical demand reduction choices, in our view, include but are not limited to the following (not intended to be an exhaustive list by any means):

- Disincentivize the use of SUVs for mass markets.
- Encourage market adoption of hybrid vehicles (e.g., Prius) that offer improved fuel economy with minimal (or no) government subsidies.
- Introduce incentives to use mass transportation in major population centers (e.g., tax city driving during certain hours of the day using an "EZ Pass"-styled tax collection mechanism).

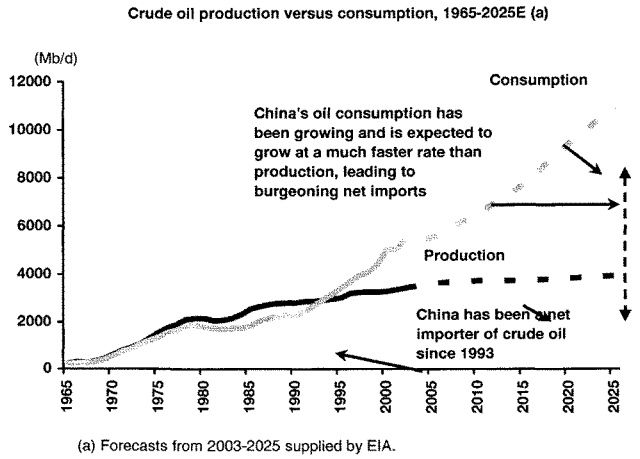
The lower the growth rate for oil demand, the less supply growth will be needed.

Exhibit 1: US refining and OPEC capacity utilization at very high levels.



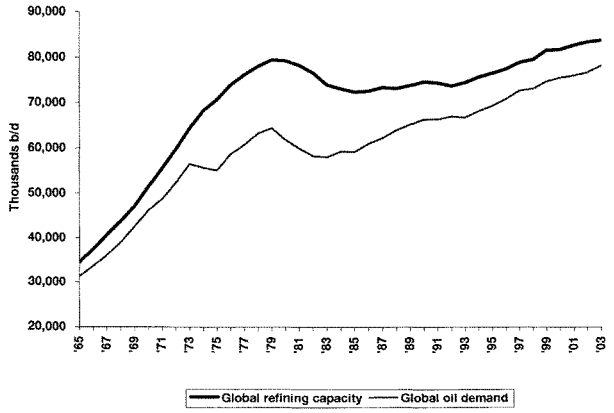
Source: Department of Energy, Platt's, MEES, IEA, BP Statistical Review of World Energy.

Exhibit 2: China has moved from having balanced oil supply/demand to an increasingly large oil importer.



Source: BP Statistical Review of World Energy 2003, EIA, CEIC, industry sources, Goldman Sachs Research estimates.

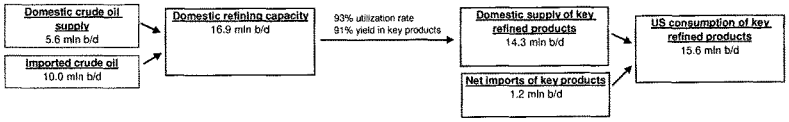
Exhibit 3: Global refining capacity expansion has not kept pace with oil demand growth since the early 1980s.



Source: BP Statistical Review of World Energy.

Exhibit 4: The state of the US refining industry is closely linked to the state of crude oil import markets.

Figures are estimates for 2004



Source: Department of Energy, Goldman Sachs Research estimates.

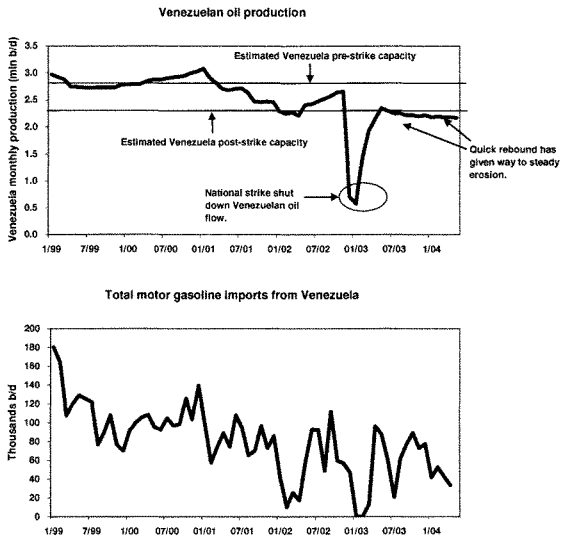
Exhibit 5: In our view, debottlenecking in refining capacity will be insufficient to meet growth in demand.

S-D outlook:

	2003	2004E	2005E	2006E	2007E	2008E	2009E	2010E
Gasoline + Distillate + Resid. demand (mln b/d)	15.21	15.52	15.77	16.02	16.27	16.53	16.80	17.07
% y-o-y	*1.9%*	*2.0%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*
y-o-y change (thous. b/d)		**304**	**248**	**252**	**256**	**260**	**265**	**269**
Demand satisfied by secular decline in inventories:								
'Normal' days coverage	27.6	26.2	25.6	25.0	24.4	23.8	23.2	22.6
'Normal' inventory levels (mln bbls)	419.9	406.6	403.6	400.5	397.2	393.7	390.0	386.0
Inventory (draw) / build (mln bbls)		(13.3)	(2.9)	(3.1)	(3.3)	(3.5)	(3.7)	(3.9)
Net implied needed G+D+R supply (incl. imports) (mln b/d)	15.22	15.48	15.76	16.01	16.27	16.52	16.79	17.06
% y-o-y		*1.7%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*
y-o-y change (thous. b/d)		**261**	**277**	**252**	**256**	**260**	**264**	**268**
Est. supply growth from debottlenecking (thous. b/d)		150	150	150	150	150	150	150
Est. growth in new refining capacity + net imports (thous. b/d)		**111**	**127**	**102**	**106**	**110**	**114**	**118**

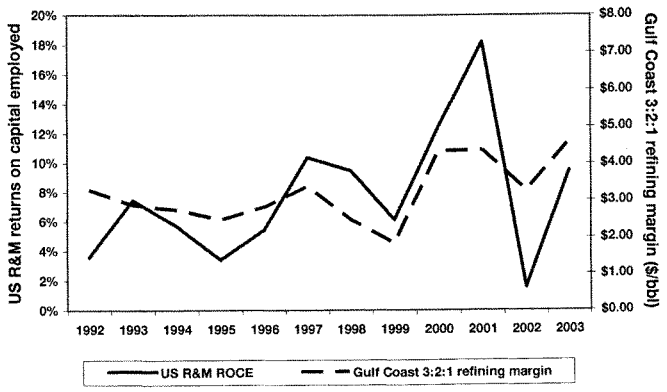
Source: Department of Energy, Goldman Sachs Research estimates.

Exhibit 6: Venezuela crude oil supply and gasoline exports to the US remain well below pre-strike levels.



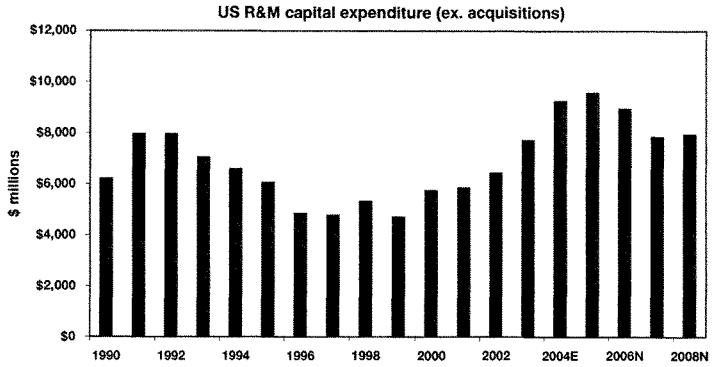
Source: Platt's, MEES, BP Statistical Review of World Energy, and DOE.

Exhibit 7: Low refining margins during most of 1990s led to poor industry profitability.



Source: Company reports, Goldman Sachs Research estimates.

Exhibit 8: US R&M CAPEX was low during most of the 1990s; the current recovery is almost exclusively to meet new environmental regulations.



Source: Company reports, Goldman Sachs Research estimates.

Exhibit 9: Sensitivity analyses: Expected retail gasoline prices and refining margins under various assumptions.

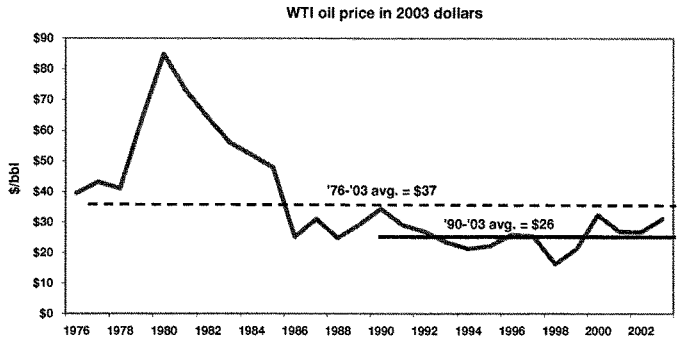
	Est. cost of new refinery	
	$2 bn	$3 bn
GC 3:2:1 crack ($/bbl)	$7.75	$9.50
Retail price ($/gallon)	$1.80	$1.95

	Est. cost of new refinery		
	$2 bn	$3 bn	
$30 WTI oil*	$1.80	$1.95	Expected retail price ($/gallon)
$50 WTI oil**	$2.05	$2.25	
$80 WTI oil***	$2.70	$3.00	

**With Gulf Coast refining margins of $7.75 and $9.50 for $2bn and $3bn cost case, respectively.*
**With Gulf Coast refining margins of $10.50 and $12.50 for $2bn and $3bn cost case, respectively.*
**With Gulf Coast refining margins of $15.00 and $17.50 for $2bn and $3bn cost case, respectively.*

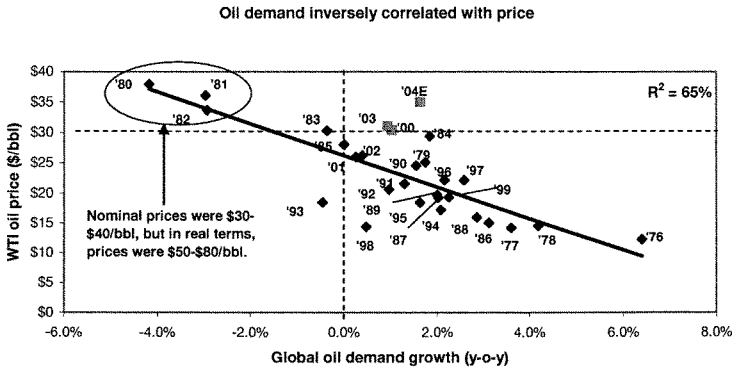
Source: Department of Energy, Bloomberg, Goldman Sachs Research estimates.

Exhibit 10: In 2003 real dollar terms, WTI oil prices average $50-$80/bbl from 1979-1984.



Source: Goldman Sachs Research estimates.

Exhibit 11: In response to an $80/bbl (real) oil price spike, oil demand growth actually fell.



Source: BP Statistical Review of World Energy, Goldman Sachs Research estimates.

Mr. HALL. Thank you, sir.
Mr. Cooper.

STATEMENT OF MARK COOPER

Mr. COOPER. Thank you, Mr. Chairman. I appreciate the opportunity and applaud the committee for inviting consumers to present their point of view. I think I have attracted a little attention with mine, judging from the previous questions.

When the first signs of trouble in the gasoline market emerged in the year 2000, CFA began to examine the underlying causes of the problem. In three reports and about half a dozen pieces of testimony to Congress, we have examined the complex interaction of factors underlying the price volatility of the past 4 years. Increasing demand here in America and around the world have tightened markets, for sure. This reinforces the pricing power of international producers. Domestic markets are tight, too, because refining capacity is tight and stocks have been kept at very low level. In our view, as you heard from previous questions, consolidation in the industry interacted with environmental policy to reduce capacity.

A 2003 study for the Rand Corporation summarized a fundamental change in the behavior of the refining industry, and I quote: "Relying on existing plants and equipment to the greatest extent possible, even if that ultimately meant curtailing output of certain refined products, discussants openly questioned the once universal imperative of a refinery not 'going short'—that is, not having enough product to meet demand. Rather than investing in operating refineries to ensure that markets are fully supplied all the time, refiners suggested that they were focusing, first, on ensuring that their branded retailers are adequately supplied by curtailing sales to the wholesale market."

Now, these business decisions interacted with environmental requirements, as the Federal Trade Commission found in its study of the 2000 price spike in the Midwest, and I quote: "A significant part of the reduction in the supply of RFG was caused by the investment decision of three firms. When determining how they would comply with restrictive EPA regulations for summer grade RFG that took effect in Spring 2000, three Midwest refiners each independently concluded it was profitable to limit capital expenditures to upgrade their refineries only to the extent necessary to supply their branded gas stations and contractual obligations. As a result of these decisions, these three firms produced in the aggregate 23 percent less summer-grade RFG. Consequently, these three firms were able to satisfy only the needs of their branded gasoline stations and their contractual obligations, and could not produce summer-grade RFG to sell on the spot market, as they had done in prior years." Now, these fundamental shifts in behavior and business decisions had an impact. Mr. Widen, on the Senate side, has weighed the corporate documents which said we have to get rid of excess capacity. They are on his Web site. You can visit it.

The GAO study now shows you the effect of that impact. In fact, we think the GAO significantly underestimates the problem for at least four reasons. First of all, it addressed only 2001 data. Those are early results. At the time, the domestic spread was up a nickel

or a dime. Today, it is 30 cents a gallon more than it was in the 1990's.

Second of all, the GAO only looks at the wholesale price, and obviously there is market power all the way down the supply chain. But more importantly, the GAO treats stock and capacity as exogenous—that is, they assume that the declining stocks and the tight capacity happens someplace else, were not the result of strategic policies. And there is a massive price increase associated with that.

In point of fact, the GAO shows what happens when an industry like this becomes concentrated, an industry in which "just in time" means "never there when you really need it." You cannot run gasoline like soybeans because you need a constant flow, and surges in demand cannot be met with any substitutes. This is an industry that has to be looked at differently.

I digressed a little bit from my initial discussion, but the members seem to be really interested in our view of what is happening in the industry.

When we started looking at this industry 3 years ago, we developed a balanced policy to look at where we would get the gasoline that the American public needs. And, frankly, we looked very hard at this question of closing refineries because those are the best opportunities for expanding capacity. Why were those 50 or 60 refineries closed in the 1990's? Senator Widen's document suggests they were strategic business decisions to tighten the market. Those are the smoking guns that are there. The effects are now clear to us.

So, we asked 3 years ago for an inventory of closed refineries. Why were they closed? What would it take to get them open? And we particularly encouraged new entry into this business, to take those sites and let other people develop them as refineries.

The interesting thing is we have heard a lot in this hearing and the last hearing I testified on refineries, about the 100 or so that closed in the 1980's. In fact, if you go back to our 2001 document, you will discover that we looked very carefully at that. When I first came to Washington to represent consumer interest, we vigorously supported the small refiner buyer, that tax subsidy that kept the little guys in business, because we realized that a few pennies a gallon to keep the independent refiner there would have a tremendous disciplining effect on the marketplace.

So, you are darn right, we want more refineries. We want them in places where they have been closed because that minimizes the environmental impact, and we want independent refiners who would discipline the price in this industry. Thank you.

[The prepared statement of Mark Cooper follows:]

PREPARED STATEMENT OF MARK COOPER, DIRECTOR OF RESEARCH, CONSUMER FEDERATION OF AMERICA, ON BEHALF OF CONSUMER FEDERATION OF AMERICA AND CONSUMERS UNION

Mr. Chairman and Members of the Committee, my name is Dr. Mark Cooper. I am Director of Research of the Consumer Federation of America. The Consumer Federation of America (CFA) is a non-profit association of 300 groups, which was founded in 1968 to advance the consumer interest through research, advocacy and education. I am also testifying on behalf of Consumers Union, the independent, non-profit publisher of *Consumer Reports*.

I greatly appreciate the opportunity to appear before you today to discuss the problem of rising gasoline prices and gasoline price spikes, and the impact that environmental regulations may have on these increases. Over the past two years, our

organizations have looked in detail at the oil industry and the broad range of factors that have affected rising oil and gasoline prices. We submit two major studies conducted by the Consumer Federation of America on this topic for the record.[1]

Three years ago, the analysis we provided in one of these reports, *Ending the Gasoline Price Spiral,* showed that the explanation given by the oil industry and the Administration for the high and volatile price of gasoline is oversimplified and incomplete. This explanation points to policies that do not address important underlying causes of the problem and, therefore, will not provide a solution.

- Blaming high gasoline prices on high crude oil prices ignores the fact that over the past few years, the domestic refining and marketing sector has imposed larger increases on consumers at the pump than crude price increases would warrant.
- Blaming tight refinery markets on Clean Air Act requirements to reformulate gasoline ignores the fact that in the mid-1990s the industry adopted a business strategy of mergers and acquisitions to increase profits that was intended to tighten refinery markets and reduce competition at the pump.
- Claiming that the antitrust laws have not been violated in recent price spikes ignores the fact that forces of supply and demand are weak in energy markets and that local gasoline markets have become sufficiently concentrated to allow unilateral actions by oil companies to push prices up faster and keep them higher longer than they would be in vigorously competitive markets.
- Eliminating the small gasoline markets that result from efforts to tailor gasoline to the micro-environments of individual cities will not increase refinery capacity or improve stockpile policy to ensure lower and less volatile prices, if the same handful of companies dominate the regional markets.

Thus, the causes of record energy prices involve a complex mix of domestic and international factors. The solution must recognize both sets of factors, but the domestic factors must play an especially large part in the solution, not only because they are directly within the control of public policy, but also because careful consideration of what can and cannot be done leads to a very different set of policy recommendations than the Administration and the industry have been pushing, or the Congress is considering in the pending energy legislation.

Because domestic resources represent a very small share of the global resources base and are relatively expensive to develop, it is folly to exclusively pursue a supply-side solution to the energy problem. The increase in the amount of oil and gas produced in America will not be sufficient to put downward pressure on world prices; it will only increase oil company profits, especially if large subsidies are provided, as contemplated in pending energy legislation. Moreover, even if the U.S. could affect the market price of basic energy resources, which is very unlikely, that would not solve the larger structural problem in domestic markets.

THE UNDERLYING STRUCTURAL PROBLEM IN DOMESTIC PETROLEUM MARKETS

Our analysis shows that energy markets have become tight in America because supply has become concentrated and demand growth has put pressure on energy markets. This gave a handful of large companies pricing power and rendered the energy markets vulnerable to price shocks. While the operation of the domestic energy market is complex and many factors contribute to pricing problems, one central characteristic of the industry stands out—it has become so concentrated in several parts of the country that competitive market forces are weak. Long-term strategic decisions by the industry about production capacity interact with short-term (mis)management of stocks to create a tight supply situation that provides ample opportunities to push prices up quickly. Because there are few firms in the market and because consumers cannot easily cut back on energy consumption, prices hold above competitive levels for significant periods of time.

The problem is not a conspiracy, but the rational action of large companies with market power. With weak competitive market forces, individual companies have flexibility for strategic actions that raise prices and profits. Individual companies can let supplies become tight in their area and keep stocks low, since there are few competitors who might counter this strategy. Companies can simply push prices up when demand increases because they have no fear that competitors will not raise prices to steal customers. Individual companies do not feel compelled to quickly increase supplies with imports, because their control of refining and distribution ensures that competitors will not be able to deliver supplies to the market in their

[1] Cooper, Mark, *Ending the Gasoline Price Spiral* (Washington D.C.: Consumer Federation of America July 2001). Cooper, Mark, *Spring Break in the Oil Industry: Price Spikes, Excess Profits and Excuses* (Washington D.C.: Consumer Federation of America, October 2003.)

area. Because there are so few suppliers and capacity is so tight, it is easy to keep track of potential threats to this profit maximizing strategy. Every accident or blip in the market triggers a price shock and profits mount. Moreover, operating the complex system at very high levels of capacity places strains on the physical infrastructure and renders it susceptible to accidents.

It has become evident that stocks of product are the key variables that determine price shocks. In other words, stocks are not only the key variable; they are also a strategic variable. The industry does a miserable job of managing stocks and supplying product from the consumer point of view. Policymakers have done nothing to force them to do a better job. If the industry were vigorously competitive, each firm would have to worry a great deal more about being caught with short supplies or inadequate capacity and they would hesitate to raise prices for fear of losing sales to competitors. Oil companies do not behave this way because they have power over price and can control supply. Mergers and acquisitions have created a concentrated industry in several sections of the country and segments of the industry. The amount of capacity and stocks and product on hand are no longer dictated by market forces, they can be manipulated by the oil industry oligopoly to maximize profits.

Much of this increase in industry profits, of course, has been caused by an intentional withholding of gasoline supplies by the oil industry. In a March 2001 report, the Federal Trade Commission (FTC) noted that by withholding supply, industry was able to drive prices up, and thereby maximize profits.[2] The FTC identified the complex factors in the spike and issued a warning.

> The spike appears to have been caused by a mixture of structural and operating decisions made previously (high capacity utilization, low inventory levels, the choice of ethanol as an oxygenate), unexpected occurrences (pipeline breaks, production difficulties), errors by refiners in forecasting industry supply (misestimating supply, slow reactions), and decisions by firms to maximize their profits (curtailing production, keeping available supply off the market). The damage was ultimately limited by the ability of the industry to respond to the price spike within three or four weeks with increased supply of products. However, if the problem was short-term, so too was the resolution, and similar price spikes are capable of replication. Unless gasoline demand abates or refining capacity grows, price spikes are likely to occur in the future in the Midwest and other areas of the country.[3]

A 2003 Rand study of the refinery sector reaffirmed the importance of the decisions to restrict supply. It pointed out a change in attitude in the industry, wherein "[i]ncreasing capacity and output to gain market share or to offset the cost of regulatory upgrades is now frowned upon."[4] In its place we find a "more discriminating approach to investment and supplying the market that emphasized maximizing margins and returns on investment rather than product output or market share."[5] The central tactic is to allow markets to become tight.

> Relying on . . . existing plants and equipment to the greatest possible extent, even if that ultimately meant curtailing output of certain refined product . . . openly questioned the once-universal imperative of a refinery not "going short"—that is not having enough product to meet market demand. Rather than investing in and operating refineries to ensure that markets are fully supplied all the time, refiners suggested that they were focusing first on ensuring that their branded retailers are adequately supply by curtaining sales to wholesale market if needed.[6]

The Rand study drew a direct link between long-term structural changes and the behavioral changes in the industry, drawing the connection between the business strategies to increase profitability and the pricing volatility. It issued the same warning that the FTC had offered two years earlier.

> For operating companies, the elimination of excess capacity represents a significant business accomplishment: low profits in the 1980s and 1990s were blamed in part on overcapacity in the sector. Since the mid-1990s, economic performance industry-wide has recovered and reached record levels in 2001. On the other hand, for consumers, the elimination of spare capacity generates upward pressure on prices at the pump and produces short-term market vulnerabilities. Disruptions in refinery operations resulting from scheduled maintenance and

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[2] Federal Trade Commission, *Midwest Gasoline Price Investigation,* March 29, 2001.

[3] Federal Trade Commission, *Midwest Gasoline Price Investigation,* March 29, 2001, pp. i . . . 4.

[4] Peterson, D.J. and Serej Mahnovski, *New Forces at Work in Refining: Industry Views of Critical Business and Operations Trends* (Santa Monica, CA: RAND Corporation, 2003), p. 16.

[5] Peterson and Mahnovksi, p. 42.

[6] Peterson and Mahnovksi, p. 17.

overhauls or unscheduled breakdowns are more likely to lead to acute (i.e., measured in weeks) supply shortfalls and price spikes.[7]

The spikes in the refiner and marketer take at the pump in 2002, 2003, and early 2004, were larger than the 2000 spike that was studied by the FTC. The weeks of elevated prices now stretch into months. The market does not correct itself. The roller coaster has become a ratchet. The combination of structural changes and business strategies has ended up costing consumers billions of dollars. Until the Federal government is willing to step in to stop oil companies from employing this anti-consumer strategy, there is no reason to believe that they will abandon this practice on their own.

A COMPREHENSIVE DOMESTIC SOLUTION

As we demonstrated in a report last year, *Spring Break In the U.S. Oil Industry: Price Spikes, Excess Profits and Excuses,*[8] the structural conditions in the domestic gasoline industry have only gotten worse as demand continues to grow and mergers have been consummated. The increases in prices and industry profits should come as no surprise.

We all would like immediate, short-term relief from the current high prices, but what we need is an end to the roller coaster and the ratchet of energy prices. That demands a balanced, long-term solution. Breaking OPEC's pricing power would relieve a great deal of pressure from consumers' energy bills, but the short-term prospects are not promising in that regard either. There, too, we need a long-term strategy that works on market fundamentals.

Three years ago, we outlined a comprehensive policy to implement permanent institutional changes that would reduce the chances that markets will be tight and reduce the exposure of consumers to the opportunistic exploitation of markets when they become tight. Those policies made sense then; they make even more sense today. The Federal government has done little to move policy in that direction since it declared an energy crisis in early 2001.

To achieve this reduction of risk, public policy should be focused on achieving four primary goals:

- Restore reserve margins by increasing both fuel efficiency (demand-side) and production capacity (supply-side).
- Increase market flexibility through stock and storage policy.
- Discourage private actions that make markets tight and/or exploit market disruptions by countering the tendency to profiteer by withholding of supply.
- Promote a more competitive industry.

Expand Reserve Margins by Striking a Balance Between Demand Reduction and Supply Increases

Improving vehicle efficiency (reduction in fleet average miles per gallon) equal to economy wide productivity over the past decade (when the fleet failed to progress) would have a major impact on demand. It would require the fleet average to improve at the same rate it did in the 1980s. It would raise average fuel efficiency by five miles per gallon, or 20 percent over a decade. This is a mid-term target. This rate of improvement should be sustainable for several decades. This would reduce demand by 1.5 million barrels per day and return consumption to the level of the mid-1980s.

Expanding refinery capacity by ten percent equals approximately 1.5 million barrels per day. This would require 15 new refineries, if the average size equals the refineries currently in use. This is less than one-third the number shut down in the past ten years and less than one-quarter of the number shut down in the past fifteen years. Alternatively, a ten percent increase in the size of existing refineries, which is the rate at which they increased over the 1990s, would do the trick, as long as no additional refineries were shut down.

Placed in the context of redevelopment of recently abandoned facilities or expansion of existing facilities, the task of adding refinery capacity does not appear daunting. Such an expansion of capacity has not been in the interest of the businesses making the capacity decisions. Therefore, public policies to identify sites, study why so many facilities have been shut down, and establish programs to expand capacity should be pursued.

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[7] Peterson and Mahnovski, p. xvi.

[8] Cooper, Mark, *Spring Break in the Oil Industry: Price Spikes, Excess Profits and Excuses* (Washington D.C.: Consumer Federation of America, October 2003.

Expanding Storage and Stocks

It has become more and more evident that private decisions on the holding of crude and product in storage will maximize short-term private profits to the detriment of the public. Increasing concentration and inadequate competition allows stocks to be drawn down to levels that send markets into price spirals.

The Strategic Petroleum Reserve is a crude oil stockpile that has been developed as a strategic developed for dire emergencies that would result in severe shortfalls of crude.[9] It could be viewed and used differently, but it has never been used as an economic reserve to respond to price increases. Given its history, draw-down of the SPR is at best a short-term response.

Private oil companies generally take care of storage of crude oil and product to meet the ebb and flow of demand.[10] The experience of the past four years indicates that the marketplace is not attending to economic stockpiles. Companies do not willingly hold excess capacity for the express purpose of preventing price increases. They will only do so if they fear that a lack of supply or an increase in brand price would cause them to lose business to competitors who have available stocks. Regional gasoline markets appear to lack sufficient competition to discipline anti-consumer private storage policies.

Public policy must expand economic stocks of crude and product. Gasoline distributors (wholesale and/retail) can be required to hold stocks as a percentage of retail sales. Public policy could also either directly support or give incentives for private parties to have sufficient storage of product. It could lower the cost of storage through tax incentives when drawing down stocks during seasonal peaks. Finally, public policy could directly underwrite stockpiles. We now have a small Northeast heating oil reserve. It should be continued and sized to discipline price shocks, not just prevent shortages. Similarly, a Midwest gasoline stockpile should be considered.

Reducing Incentives for Market Manipulation

In the short term, government must turn the spotlight on business decisions that make markets tight or exploit them. Withholding of supply should draw immediate and intense public scrutiny, backed up with investigations. Since the federal government is likely to be subject to political pressures not to take action, state government should be authorized and supported in market monitoring efforts. A joint task force of federal and state attorneys general could be established on a continuing basis. The task force should develop databases and information to analyze the structure, conduct and performance of gasoline and natural gas markets.

As long as huge windfall profits can be made, private sector market participants will have a strong incentive to keep markets tight. The pattern of repeated price spikes and volatility has now become an enduring problem. Because the elasticity of demand is so low—because gasoline and natural gas are so important to economic and social life—this type of profiteering should be discouraged. A windfall profits tax that kicks in under specific circumstances would take the fun and profit out of market manipulation.

Ultimately, market manipulation, including the deliberate withholding of supply, should be made illegal. This is particularly important for commodity and derivative markets.

Promoting a Workably Competitive Market

Further concentration of these industries is quite problematic. The Department of Justice Merger Guidelines should be rigorously enforced. Moreover, the efficiency defense of consolidation should be viewed skeptically, since inadequate capacity is a problem in these markets. The low elasticity of supply and demand should be considered in antitrust analysis.

Restrictive marketing practices, such as zonal pricing and franchise restrictions on supply acquisition, should be examined and discouraged. These practices restrict flows of product into markets at key moments.

Consideration of expanding markets with more uniform reformulation requirements should not involve a relaxation of clean air requirements. Any expansion of markets should ensure that total refinery capacity is not reduced.

Every time energy prices spike, policymakers scramble for quick fixes. Distracted by short-term approaches and focused on placing blame on foreign energy producers and environmental laws, policymakers have failed to address the fundamental

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[9] Gove, Philip Babcock, *Webster's Third New International Dictionary* (Springfield MA: 1986), p. 2247, "a reserve supply of something essential as processed food or a raw material) accumulated within a country for use during a shortage caused by emergency conditions (as war)."

[10] Gove, *Webster's Third International,* p. 2252, "The holding and housing of goods from the time they are produced until their sale."

causes of the problem. In the four years since the energy markets in the United States began to spin out of control we have done nothing to increase competition, ensure expansion of capacity, require economically and socially responsible management of crude and product stocks, or slow the growth of demand by promoting energy efficiency. We have wasted four years and consumers are paying the price with record highs at the pump.

[Additional material submitted is retained in subcommittee files:]

Mr. HALL. Thank you, Dr. Cooper.

The Chair recognizes Mr. Slaughter.

STATEMENT OF BOB SLAUGHTER

Mr. SLAUGHTER. Thank you, Mr. Chairman. The first thing I would like to do is thank you for holding this hearing. As head of the refining association that basically all refiners belong to in the United States, with very few exceptions, we thank you for looking at our issues.

The first map shows the dispersal of refineries currently around the United States, both large and small. We do have 149 operating refineries, with 60 different refining companies operating them.

The second chart just again shows the importance of crude oil cost to the cost of making gasoline. Crude oil accounts for 40 percent of the total cost, and taxes for 21, which leaves 61 cents of the cost of making a gallon of gasoline essentially outside the control of refiners.

We do know crude costs are up well over 50 percent since April 2003. Great competition for barrels around the world. A lot of growth in Asia. We have OPEC decisions affecting the market in uncertainty in many producing countries.

The refining number does include costs and profits, it is currently at 31 cents, but it varies considerably. This is a higher number than usual.

On Chart 3 shows the correlation of crude prices and gasoline costs, basically, again, underscoring that crude is a very important factor.

U.S. demand is also very high, as has been testified here, in the 9 million barrels a day range, perhaps moving to 9.4. Refiners are responding to this by running at 95, 96, 98 percent in some cases, utilization of their facilities, having provided 2.6 percent more gasoline in January and May of this year than in the same period 1 year ago. This is despite several difficulties, including MTBE bans in a sixth of the U.S. gas market, with a corresponding loss of volume that occurs when you try to replace MTBE with ethanol. Unfortunately, the factors on the last two charts you have seen are largely beyond policy control.

The next chart shows what we call the "regulatory blizzard." It shows the 14 major regulatory programs that the industry has to comply with in the 2000 to 2010 timeframe. Over $20 billion of investment capital—and you see we are roughly at midpoint in a number of those, particularly the diesel and gasoline sulfur-reduction programs, which amount to nothing less than the redesign of two-thirds of the product slate for refiners across the country, removing 90 percent of the sulfur from gasoline and 95 percent of the sulfur from diesel. Very expensive programs. We are always concerned about supply impacts, but very much committed to these programs.

The refining industry is, I want to say, an extremely well-regulated industry. Even financial transactions, as has been discussed this morning, are extremely transparent. The Enforcement Office at EPA recently said in a document, "Few industries are as complex as petroleum refining." Few regulatory programs are as complex as the Clean Air Act, which, for us, has been more telling as to what we will have to do than any energy policy passed for the last 20 years. And so we are glad to be here talking to an authorizing subcommittee for the Clean Air Act, which is the most important statute that regulates us.

Just to point out a fact, looking at things and the regulating universe, large refineries can have 500,000 different components and small refineries 60,000 different components that are regulated by different programs basically under the auspices of EPA. So, it is an extremely complex business that requires a lot of capital.

If I could see the next chart that shows the divergence between U.S. demand for petroleum products and the domestic petroleum product supplied by the refining industry. You will see a divergence. U.S. refining capacity is down 10 percent since 1981, but the demand for petroleum products is up 25 percent. The outlook is for continued divergence through 2025. As is well noted, there have been no new refineries built in the last 25, 26 years. Capacity growth has been slow at existing facilities, if at all, and we encourage people to do everything they can to encourage capacity growth at existing facilities because that is where the lion's share of any capacity growth we are able to do is going to come from.

What has been said, though, given this chart this morning, and stressed, the incremental barrel of product comes from abroad, with increasing competition for those imports around the world. People who supply imports to the United States may not invest if we don't take into account the impact of our new specifications on them. So, it affects both our supply of imports as well as refined products. But very importantly, you have got to keep an attractive investment climate for the refining industry because you want people to continue to be able to make these large investments in domestic refining capacity. That means we need to be more careful with the cost of environmental programs. We need to move ahead, but balance the environmental objectives with the energy supply objectives, and accept the need to encourage capacity of domestic refiners. That means taking a sharper pencil than we have in the past, to the cost of some of particularly the environmental regulations. The refining industry has spent roughly $50 billion on environmental regulations over the last decade.

I do want to state industry is not asking for a rollback of existing environmental regulations. We have invested money particularly, a great deal of money, in the gasoline sulfur and diesel sulfur reductions, and are absolutely committed to their implementation, but we believe that environmental policy does include real cost, significant cost, in the billions of dollars, and can be done more efficiently.

I will be glad to take any questions that the committee has. Thank you.

[The prepared statement of Bob Slaughter follows:]

PREPARED STATEMENT OF BOB SLAUGHTER, PRESIDENT, NATIONAL PETROCHEMICAL & REFINERS ASSOCIATION

OVERVIEW

Mr. Chairman and members of the Subcommittee, thank you for the opportunity to appear today to discuss the factors impacting current gasoline markets, especially U.S. refining capacity and boutique fuels. I am Bob Slaughter, President of NPRA, the National Petrochemical & Refiners Association.

NPRA is a national trade association with 450 members, including those who own or operate virtually all U.S. refining capacity, and most U.S. petrochemical manufacturers.

To summarize our message today, we urge policymakers in Congress and the Administration to support policies that encourage the production of an abundant supply of petroleum products for U.S. consumers. We believe that a diverse and healthy domestic refining industry is a necessary foundation to attain that objective. We also believe that government actions, especially in the environmental area, can and must do a better job of balancing energy supply impacts and other policy objectives.

NPRA supports requirements for the orderly production and use of cleaner-burning fuels to address health and environmental concerns, while at the same time maintaining the flow of adequate and affordable gasoline and diesel supplies to the consuming public. Refiners have made important contributions to national efforts to improve the environment.

Since 1970, clean fuels and clean vehicles account for about 70% of U.S. emission reductions from all sources, according to EPA. Over the past 10 years, U.S. refiners have invested about $47 billion in environmental improvements, much of that to make cleaner fuels. And also according to EPA, the new Tier 2 low sulfur gasoline program, which began in January 2004, will have the same effect as removing 164 million cars from the road when fully implemented in 2006.

As for current gasoline market conditions, there are no silver bullet solutions to the current tight supply/demand balance. The two most significant factors in today's gasoline market are the high price of crude oil and strong year to date demand for gasoline because of the improving U.S. economy. U.S. refineries are responding quite effectively to this challenge by producing record amounts of gasoline and distillates so far this year.

Here is a summary of the key factors affecting the current gasoline market:

- Higher crude oil costs (This year WTI crude oil has twice crossed the $40 per barrel threshold.);
- Increased consumer demand (The Energy Information Administration (EIA) calculates current gasoline demand at a near record 9.4 million b/d);
- Implementation of state MTBE bans and an ethanol mandate in California, Connecticut, & New York (These states represent one-sixth of U.S. gasoline sales.);
- Rollout of Tier 2 gasoline with reduced sulfur, a new standard which earlier this year may have temporarily affected gasoline imports; and
- The annual changeover to summer fuel formulations beginning in early spring.

Refiners understand that increased costs for gasoline can cause difficulties for consumers, despite the fact that gasoline prices have actually declined over the past two decades when adjusted for inflation. However, NPRA urges Congress, the Administration, and the motoring public to have continued patience with the free market system. Refiners are working hard to meet strong demand for their products while complying with extensive regulatory controls that affect both refining facilities and products.

To summarize our policy recommendations, we first urge Congress to pass the Conference Report on HR 6. This is the most important action that can be taken to improve U.S. energy security. Putting the conference report on the President's desk is the best way to move energy policy forward into the 21st century. Congress should also support the New Source Review (NSR) reforms which have been considered by two Administrations. These reforms will encourage capacity expansions and efficient operation of existing refineries by encouraging installation of new technologies. Congress should resist any new "federal fuel recipes" or hasty action on the subject of boutique fuels. Even the experts can't agree on the definition of a "boutique fuel." We need more data before acting on this issue, and the study in H.R. 6 is a necessary first step. Congress should also act to repeal the 2% RFG oxygenation requirement and support California and New York's waiver requests pending repeal.

TODAY'S GASOLINE MARKET: REFINERS FACE HIGH FEEDSTOCK PRICES; STRONG DEMAND

The most significant factor affecting gasoline costs is the higher price of crude oil. This input currently accounts for 40% of the cost of a gallon of gasoline, while taxes add another 21% to the price. Thus, over 60% of the retail cost of gallon of gasoline is attributable to two components that are beyond the control of refiners. (See Attachment 1)

Higher crude oil prices, set on international markets, are responsible for most of the increased gasoline costs. When crude oil prices are above $40 per barrel, refiners are paying around $1.00 for each gallon of crude oil used to make a gallon of gasoline. Thus, crude oil and gasoline costs closely track each other. (See Attachment 2)

Since April of 2003, crude oil prices have escalated roughly 52%. Factors driving crude prices include: (1) high demand, spurred by significant economic growth in Asia, (2) decisions by OPEC regarding output, and (3) recurring uncertainties about worldwide crude and product production capabilities due to political instability in some producing nations.

According to the International Energy Agency (IEA), economic expansion is behind the largest increase in world oil demand in 16 years. In the U.S., oil demand is up 2.8 percent over a year ago. International demand is projected to be up 2.9 percent this year. China's demand saw a 23 percent year-on-year increase during the second quarter. Last year, China's crude oil imports grew 36 percent, making China the second largest importer of crude oil in the world, after the United States. India and other Asian countries have also seen strong demand growth.

A tight supply/demand balance in the U.S. gasoline market is a second significant factor affecting current gasoline costs. As the U.S. economy improves, Americans are consuming more gasoline, with demand up almost three percent compared with last year. U.S. refiners are producing record amounts of the fuel, but strong demand and an earlier reduction in gasoline imports have tightened supply. Thus, even with refineries running flat-out at 96% average capacity utilization rates, strong demand has kept gasoline inventories below average.

Gasoline demand currently averages approximately 9 million barrels per day. Domestic refineries produce about 90 percent of U.S. gasoline supply, while about 10 percent is imported. Increased gasoline demand can be met only by increasing domestic refinery production or by relying on more foreign gasoline imports. Unfortunately, the need for more domestic gasoline production capacity has run up against government policies and public attitudes that make it difficult and sometimes impossible to increase domestic refining capacity.

PUBLIC POLICY SHOULD ENCOURAGE A HEALTHY DOMESTIC REFINING INDUSTRY AND U.S. CAPACITY EXPANSION

Domestic refining capacity is a scarce asset. Currently 149 U.S. refineries, owned by almost 60 companies, operate in 33 states. (See Attachment 3) Their total crude oil processing capacity is 16.9 million barrels per day. In 1981, there were 325 refineries in the U.S. with a capacity of 18.6 million barrels per day. Thus, while U.S. demand for petroleum products has increased over 20% in the last twenty years, U.S. refining capacity has decreased by 10%. (See Attachment 4) No new refinery has been built in the United States since 1976, and it is unlikely that one will be built here in the foreseeable future, due to the combined impact of economic, government policy and "not in my backyard" NIMBY public attitudes. (Major economic factors include siting costs, environmental requirements, and industry profitability.) During this time, however, refiners have upgraded and modernized existing facilities by installing new technologies and enhanced emissions controls. The result is that refineries have improved their environmental performance, despite the many challenges posed by major investments in new fuels programs. Of course, refiners will continue to invest to improve the environmental performance of these facilities.

U.S. refining capacity increased slightly in the past decade, with minimal increase in the past three years. Because new refineries have not been built, refiners have sought to increase capacity at existing sites to offset increasing demand and the closure of some U.S. refineries. Unfortunately, it is becoming harder to add capacity at existing sites, due in part to more stringent environmental regulations and the impact of a complex and often lengthy permitting process. Proposed refinery projects can become difficult and contentious at the state or local level, even when necessary to produce cleaner fuels under new regulatory programs. One NPRA member company encountered more than a year's wait for an ethanol tank necessary to comply with California's *de facto* ethanol mandate. In another instance, a group of investors has been trying to build a new refinery in Arizona where population and product

demand are growing fast. So far, they have little to show for their determined efforts.

NPRA believes that two policy initiatives in particular could help address some of the obstacles to capacity expansion.

First, Congress should enact legislation that streamlines the permitting process for refinery expansion projects, new refineries, and other key refining projects. Congress should consider declaring expansion of U.S. refining capacity a national priority, and provide guidelines for consideration of refining permits. These guidelines should provide significant but finite opportunities for public input and enforceable deadlines for decisions. The legislation should also create incentives for federal, state and local permitting authorities to make refining-related projects a priority. EPA or other federal authorities could be directed to offer assistance to states to assist them in permit review.

Second, NPRA urges policymakers to support New Source Review (NSR) reform so that domestic refiners can continue to meet the growing public demand for gasoline and comply with new environmental programs. These reforms have been under consideration since 1996 by two Administrations, and reflect significant public review and comment. The two reforms which have been completed respond to a widespread consensus that the unreformed program lacked clarity and certainty, discouraging refiners and other manufacturers in their attempts to modernize or even to repair existing facilities. NSR reforms should facilitate new domestic refining capacity expansions. They will encourage the installation of more technologically-advanced equipment and provide greater operational flexibility while maintaining a facility's environmental performance. Unfortunately, the much-needed NSR reforms are currently caught up in litigation, when refiners and U.S. consumers are most in need of their immediate implementation.

It is clearly in our nation's best interest to manufacture the vast majority of petroleum products for U.S. consumption in domestic refineries. Nevertheless, we currently import more than 62% of the crude oil and petroleum products we consume. Limited U.S. refining capacity affects the U.S. supply of refined petroleum products and the flexibility of the supply system, particularly in times of unforeseen disruption or other stress. Unfortunately, the U.S. Energy Information Administration (EIA) currently predicts "substantial growth" in refining capacity in the Middle East, Central and South America, and the Asia/Pacific region, not the U.S.

THE DOMESTIC REFINING INDUSTRY IS DIVERSE AND HIGHLY COMPETITIVE

Today's U.S. refining industry is highly competitive. Despite this fact, some have suggested that past mergers are responsible for higher prices. The data do not support such claims. Companies have become more efficient and continue to compete fiercely. There are almost 60 refining companies in the U.S., and the largest refiner accounts for only about 13% of the nation's total refining capacity. The Federal Trade Commission (FTC) thoroughly evaluates every industry merger or acquisition and subjects these proposals to a strict review for any adverse impact on competition.

Once the transaction is complete, the FTC continues to subject the industry to a high level of ongoing scrutiny. State and federal investigations of price spikes have consistently cleared the industry of any wrongdoing. For example, after a 9-month FTC investigation into the causes of price spikes in local markets in the Midwest during the spring and summer of 2000, former FTC Chairman Robert Pitofsky stated, "There were many causes for the extraordinary price spikes in Midwest markets. Importantly, there is no evidence that the price increases were a result of conspiracy or any other antitrust violation. Indeed, most of the causes were beyond the immediate control of the oil companies." On April 25, 2002, Chairman Pitofsky appeared before the Senate Commerce Committee. His testimony detailed the Commission's efforts to review proposed oil industry mergers, including requiring significant assets sales to eliminate competitive concerns. He said, "...the merger wave reflects a dynamic economy which, on the whole, is a positive phenomenon."

A recent U.S. General Accounting Office (GAO) report concluded that mergers and acquisitions have increased average wholesale gasoline prices by one-half cent per gallon. However, even this modest figure is strongly suspect. FTC chairman Timothy J. Muris strongly criticized the reliability of the GAO report, citing "major methodological mistakes that make its quantitative analyses wholly unreliable;...critical factual assumptions that are both unstated and unjustified; and...conclusions that lack any quantitative foundation."

Other evidence appears to undermine the GAO's conclusions. A comparison of EIA price data for the six years before the mergers (1990-1996) and a similar period

after (1997-2003), indicates a reduction of five cents on average in retail prices occurred during the latter period.

Merger critics sometimes suggest that the industry can affect prices because it has become much more concentrated, with a handful of companies controlling most of the market. This is untrue. According to data compiled by the U.S. Department of Commerce and by Public Citizen, in 2003 the four largest U.S. refining companies controlled a little more than 40% of the nation's refining capacity. In contrast, the top four companies in the auto manufacturing, brewing, tobacco, floor coverings and breakfast cereals industries controlled between 80% and 90% of the market.

REFINERS ARE WORKING HARD TO KEEP PACE WITH GROWING DEMAND FOR GASOLINE AND OTHER PRODUCTS

Refiners are addressing supply challenges and working hard to supply sufficient volumes of gasoline and other petroleum products to the public. During the four-week period ending July 2, 2004, the EIA reported that refiners produced 8.7 million barrels per day of gasoline, a 2.6% increase over the same period last year.

Refineries are running at record levels, producing record amounts of gasoline and distillate for this time of year. Refiners have operated at an average utilization rate of 96% since before the start of the summer driving season. To put this in perspective, peak utilization rates for other manufacturers average about 82%. At times during the summer, refiners operate at rates close to 98%. However, such high rates cannot be sustained for long periods.

In addition to coping with the higher fuel costs and growing demand, refiners are implementing a transition to cleaner gasoline across most of the nation. The sulfur level in gasoline was reduced from an average of 300 parts per million (ppm) to a corporate average of 120 ppm effective January 1, 2004, giving refiners an additional challenge in both the manufacture and distribution of fuel. Average gasoline sulfur content will be further reduced to 90 ppm on January 1, 2005, and to 30 ppm on January 1, 2006 (California already has a 30 ppm sulfur cap). Refiners across the industry are investing $8 billion dollars to achieve these significant reductions in gasoline sulfur, a source of harmful air emissions. The industry is investing another $8-10 billion to achieve equally significant reductions in the sulfur content of diesel fuel.

Of equal importance, California, New York and Connecticut bans on use of MTBE went into effect January 1. This is a major change affecting one-sixth of the nation's gasoline market. Where MTBE was used as an oxygenate in reformulated gasoline, it accounted for as much as 11% of RFG supply at its peak, and substitution of ethanol for MTBE does not replace all of the volume lost by removing MTBE. (Ethanol's properties limit its ability to substitute for lost MTBE volume; it actually replaces less than 50% of the volume lost when MTBE is removed.) That missing portion of supply must be replaced by additional production of gasoline or gasoline blendstocks.

Apparently due to these changes in gasoline specifications, the volume of gasoline imports declined roughly 7% year-to-date, although import volumes have recently increased. Gasoline imports account for about 10% of the U.S. market. They are especially important to PADD 1 (the East Coast) where imports constitute 20% of supply. As U.S. fuel specifications change, foreign refiners may not be able to supply the U.S. market without making expensive upgrades at their facilities. They may eventually elect to do so, but a time lag may occur, with potentially adverse impacts on gasoline supply in the meantime.

Refiners have also completed the annual switch to summer gasoline blends, a process which was complicated by the new ethanol mandate in markets like New York, Connecticut and California that previously experienced little ethanol use. These complications reflect the need to adjust the gasoline blend for increased emissions of ozone precursors in warm weather. Even without this complication, the seasonal switching sometimes impacted the market in recent years because storage tanks must be completely drained to accommodate summer fuel.

Obviously, refiners face a daunting task in rationalizing all these changes to provide the fuels that consumers and the nation's economy depend on. But they are succeeding. And regardless of recent press stories, we need to remember that American gasoline and other petroleum products remain a bargain when compared to the price consumers pay for those products in other large industrialized nations.

REFINERS ARE HEAVILY REGULATED; THEY FACE A BLIZZARD OF NEW ENVIRONMENTAL REQUIREMENTS FOR BOTH FACILITIES AND PRODUCTS.

Refiners currently face the massive task of complying with fourteen new environmental regulatory programs with significant investment requirements, all in the

same 2002—2010 timeframe. (See Attachment 5) For the most part, these regulations are undertaken pursuant to the Clean Air Act. Some will require additional emission reductions at facilities and plants, while others require further changes in clean fuel specifications. NPRA estimates that refiners are in the process of investing about $20 billion to sharply reduce the sulfur content of gasoline and both highway and off-road diesel (These costs do not include significant additional investments needed to comply with stationary source regulations affecting refineries). And refiners may also face additional investment requirements to deal with limitations on ether use, as well as compliance costs for controls on Mobile Source Air Toxics and other limitations.

On the horizon are still other potential environmental regulations which could force additional large investment requirements. They are: the challenges posed by increased ethanol use, possible additional changes in diesel fuel content involving cetane, and potential proliferation of new fuel specifications driven by the need for states to comply with the new eight-hour NAAQS ozone standard. The new 8-hour standard could also result in more regulations affecting facilities such as refiners and petrochemical plants. The industry must also supply two new mandatory RFG areas (Atlanta and Baton Rouge) under the "bump up" policy of the current one-hour ozone NAAQS.

These are only some of the pending and potential air quality challenges that the industry faces. Refineries are also subject to extensive regulations under the Clean Water Act, Toxic Substances Control Act, Safe Drinking Water Act, Oil Pollution Act of 1990, Resource Conservation and Recovery Act, Emergency Planning and Community Right-To-Know (EPCRA), Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and other federal statutes. The industry also complies with OSHA standards and many state statutes. A complete list of federal regulations impacting refineries is included with this statement. (See Attachment 6)

The American Petroleum Institute (API) estimates that, since 1993, about $89 billion (an average of $9 billion per year) has been spent by the oil and gas industry to protect the environment. This amounts to $308 for each person in the United States. And more than half of the $89 billion was spent in the refining sector.

A KEY GOVERNMENT ADVISORY PANEL URGED REGULATORS TO PAY MORE ATTENTION TO SUPPLY CONCERNS

In 2000, the National Petroleum Council (NPC) issued a landmark report on the state of the refining industry. Given the limited return on investment in the industry and the capital requirements of environmental regulations, the NPC urged policymakers to pay special attention to the timing and sequencing of any changes in product specifications. Failing such action, the report cautioned that adverse fuel supply ramifications could result. Unfortunately, this warning has been widely disregarded. On June 22, 2004, Energy Secretary Abraham asked NPC to update and expand its refining study with a completion date of September 30, 2004. Information in this new study could be used to improve energy policy. Unfortunately, there is little evidence that the NPC's 2000 recommendations were implemented.

Some policymakers seem to recoil from the obvious fact that clean fuel proposals that do much good also involve significant costs. They are not free. Those costs do affect refining industry economics and fuel production capacity. We would point to the public rulemaking record illustrating recommendations industry has made on environmental regulations over the past eight years. The refining industry has consistently supported continued environmental progress, but cautioned regulators to balance environmental and energy goals by considering the supply implications of multiple new regulatory requirements, often overlapping and poorly coordinated. We have commented on many new stationary source and fuel proposals, urging adoption of reasonable and effective standards with appropriate lead times to facilitate investment and maintain supply. Many times, if not most, industry recommendations have been rejected, as regulators opt to promulgate more stringent standards without leaving a margin of safety for energy supply security.

At the same time, when the domestic industry has made the significant capital expenditures required by the regulations, it is important that final regulations not be changed except in cases of absolute necessity. Stability and certainty in regulatory implementation is needed to encourage and recognize the investment of the regulated industry in the new regulations. A much better approach than granting waivers is to develop regulations that reflect from the outset the need for attention to fuel supply concerns before regulations are finalized, not during the implementation period after investments have already been made. Refiners are sometimes unfairly accused of seeking a "rollback" of environmental programs. This is not true.

They favor implementation on schedule once the regulation is final and investments are made.

This year, as gasoline markets began to reflect the implementation of Tier 2 gasoline sulfur reduction, policymakers seemed to consider easing the new gasoline sulfur specifications for some gasoline importers as a "relief valve" for the market, despite conflicting indications whether or not any real problems existed. This would have adversely affected the refining industry, which has already made substantial investments in gasoline sulfur reductions and is in the process of making equally large investments in diesel sulfur reductions. Even more importantly, this program change would have eliminated part of the environmental benefits of the Tier 2 program, for the benefit of foreign suppliers who did not invest, and to the detriment of U.S. refiners who did. Fortunately, EPA decided to take no action to waive gasoline sulfur requirements for importers.

And of course, when any party suggests that regulatory relief is needed on a rule of this type, it is important that EPA consult with and work closely with the EIA, which has expertise in gasoline supply and demand analysis, along with other stakeholders who will be affected by such requirements.

Waivers may merit consideration on rare occasions, and they are tools available to regulators. But there should be a high burden of proof for waiver proponents. Waivers, by their very nature, raise uncertainty and threaten unfair loss of investment in the affected market. However, where there is universal agreement that a particular *rule or policy* is no longer valid, or better options exist for reaching desired objectives, then certainly that policy should be reconsidered. An excellent example is the 2% oxygenate requirement for reformulated gasoline (RFG), which should be repealed. In the meantime, NPRA supports the waiver of the 2% requirement requested by California and New York.

REFINERS WILL DO THEIR BEST TO MEET CONTINUING SUPPLY CHALLENGES; MERGERS, ACQUISITIONS AND SOME CLOSURES WILL CONTINUE

Domestic refiners will rise to meet the supply challenges in the short and the long term with the help of policymakers and the public. They have demonstrated the ability to adapt to new challenges and maintain the supply of products needed by consumers across the nation. But certain economic realities cannot be ignored and they will impact the industry. Refiners will, in most cases, make the investments necessary to comply with the environmental programs outlined above. In some cases, however, where refiners are unable to justify the costs of investment at some facilities, facilities may close or be sold or the refiner may exit certain product markets. These are economic decisions based on facility profitability relative to the size of the required investment needed to stay in business either across the board or in one product line, such as U.S. highway diesel fuel. In the case of a refinery sale, a new owner may be able to invest and keep a facility operating that would otherwise have closed. In some cases, however, it may be difficult or impossible to find a buyer.

EIA has addressed the subject of past and future refinery closures: "Since 1987, about 1.6 million barrels per day of capacity has been closed. This represents almost 10% of today's capacity of 16.8 million barrels per calendar day . . . The United States still has 1.8 million barrels of capacity under 70 MB/CD (million barrels per calendar day) in place, and closures are expected to continue in future years. Our estimate is that closures will occur between now and 2007 at a rate of about 50-70 MB/CD per year." (EIA, J. Shore, "Supply Impact of Losing MTBE & Using Ethanol," October 2002, p. 4.)

REFINING INDUSTRY ECONOMICS ARE WIDELY MISUNDERSTOOD

Refining industry profitability is also not well understood. According to data compiled by EIA (Performance Profiles of Major Energy Producers), the ten-year average return on investment in the industry is about 5.5%; this is about what investors could receive by investing in government bonds, with little or no risk. It is also less than half of the S& P Industrials figure of a 12.7% return. In 2002, the return was a *negative* 2.7% for refining, compared to a *positive* 6.6% for the S & P Industrials. This relatively low level of refiners' return, *which incorporates the cost of capital expenditures required to meet environmental regulations,* is another reason why domestic refinery capacity additions have been modest and helps explain why new refineries are less likely to be constructed here in the U.S.

Refining industry profits as a percentage of operating capital are relatively modest. In dollars, they appear to be large due to the massive scale needed to compete in the world's largest industry. A new medium-scale refinery (100,000 to 200,000 barrels/day capacity) would cost $2 to $3 billion. And, over the last decade, compa-

nies spent about $5 billion per year on environmental compliance with refinery and fuels regulations. While they significantly improved air quality, these investments also help explain the low percentage return on refinery investment.

An important reason the industry's profitability is not well understood is because the media typically report only half the story—the dollars in profits earned. Oil companies may earn a lot of money, but only after they spend huge sums to produce and market the products they sell, and only by selling in extremely high volumes. It is by looking at "profit margins"—how much money is earned on each dollar of sales—that a more complete "profits" story is told. This year, for example, higher gasoline prices have contributed to company revenues, but average profit margins (measured as net income divided by sales) were below those of other industries in the first quarter, as reported last May in *Oil Daily* and *Business Week*. In short, industry revenues can be in the billions, but so, too, are the costs of operations.

For the first quarter of 2004, the U.S. oil and gas industry, which includes producers, refiners and marketers, earned an average of 6.9 cents on every dollar of sales. This was below the U.S. all-industry average, which was 7.5 cents. Independent refiners and marketers earned an average of just 1.8 cents on every dollar of sales, even though their profits increased 50% over the previous year. In short, it is important to keep the full story in mind when reading reports about oil industry profits.

THERE ARE NO "QUICK FIXES" TO CURRENT MARKET CONDITIONS; POLICYMAKERS AND THE PUBLIC MUST NOT LOSE FAITH IN THE FREE MARKET

Modern energy policy relies upon an important tool which encourages market participants to meet consumer demand in the most cost-efficient way: market pricing. The free market swiftly provides buyers and sellers with price and supply information to which they can quickly respond.

Industry appreciates the patience and restraint that the public and policymakers have shown in responding to current market conditions and the higher cost of gasoline. Unfortunately, in the short term there are no "silver bullets" to alleviate the higher costs of gasoline this summer. Putting the current situation in a broader, more positive perspective, however, the U.S. has some of the cleanest and least costly fuels in the world.

NPRA recommends that policymakers take particular care in weighing the impact of so-called "boutique fuel" gasolines. In many cases, these programs represent a local area's attempt to address its own air quality needs in a more cost-effective way than with RFG, which is burdened by an overly prescriptive recipe and an oxygenation mandate. Boutique fuels only result in supply problems when a refinery problem or pipeline outage occurs. (As in the Midwest in 2000 and Phoenix in 2003.) In contrast, the current market situation results from high crude prices and strong demand. There is as much disagreement about the number of boutique fuels as there is lack of hard evidence about their impact. Better to study the situation, as H.R. 6 would require, than legislate in a knowledge vacuum, which might make matters worse. Refiners believe that the elimination of the 2% RFG oxygenation requirement and widespread availability of very low sulfur gasoline beginning in 2006 will eliminate the need for boutique fuels in many regions.

Industry supports further study of the "boutique fuels" phenomenon, but urges members of the Committee to resist imposition of any fuel specification changes on top of those already in progress. Further changes in fuel specifications in the 2004—2010 timeframe could add greater uncertainty to a situation which already provides significant challenges to U.S. refiners.

REFINERS ARE COMMITTED TO SAFE AND SECURE FACILITIES

NPRA and its members are absolutely committed to keeping all our facilities as secure as possible from threats of violence or terrorism. Contrary to what a few press articles would have us believe, industry is not standing idly by, waiting for the government to act before conducting comprehensive security vulnerability assessments and implementing strong facility security measures. Refiners and petrochemical manufacturers are heavily engaged—and were even before September 11—in maintaining and enhancing facility security.

NPRA has held or has co-sponsored more than a dozen conferences and workshops dedicated to helping refiners and petrochemical manufacturers strengthen facility security. NPRA has worked with the American Petroleum Institute, the Argonne National Laboratory, and representatives of the DHS Information Analysis & Infrastructure Protection Directorate to develop a sophisticated and effective methodology for conducting facility security assessments. The methodology is the product of many minds, and it is being used successfully in large and medium-sized facili-

ties. A new edition of the methodology will be coming out soon, this one incorporating security information dealing with truck and rail transportation to and from our facilities.

We also work closely with federal, state, and local governments to address security issues. Some of these agencies include the CIA, the FBI, the Department of Transportation, the Department of Energy, the Department of Defense, the Chemical Safety and Hazard Investigation Board, and of course the Department of Homeland Security and its various components, including the U.S. Secret Service, the Transportation Security Agency, and the U.S. Coast Guard, as well as various state and local emergency response and law enforcement officers.

The U.S. Coast Guard has been particularly helpful, as refiners and petrochemical manufacturers have conducted security vulnerability assessments and implemented facility security plans pursuant to the requirements of the Maritime Transportation Security Act. NPRA estimates that more than half of all its members' facilities are subject to the Coast Guard's security regulations. The Coast Guard has made hundreds of site visits to refineries and petrochemical plants, and industry personnel are working closely with the Coast Guard to assure these facilities are kept secure.

NPRA and its members strongly believe that federal security efforts must be conducted by experienced organizations such as these, and not delegated to other branches of government that lack law enforcement and intelligence capabilities and security resources.

The Environmental Protection Agency (EPA) regulates the safe use, storage, management and disposal of many potentially dangerous substances, and will continue to do so. But EPA does not have facility security expertise. Security is not its mission. This is a role Congress has delegated to the Department of Homeland Security. NPRA is opposed to policies that would disrupt current security initiatives and splinter security responsibility away from the Department of Homeland Security.

In short, refiners and petrochemical manufacturers have spent many hours of effort and millions of dollars to enhance physical and cyber security, and they will continue to do so.

CONCLUSION

There is a very close connection between federal energy and environmental policies. Unfortunately, these policies are often debated and decided separately and thus in a vacuum. As a result, positive impacts for one policy area sometimes conflict with or even undermine goals and objectives in the other.

Industry therefore requests that an updated energy policy be adopted incorporating the principle that, in the case of new environmental initiatives affecting fuels, environmental objectives must be balanced with energy supply requirements. We believe these regulations should contain an express statement of the impact on the domestic refining industry and U.S. fuel supply. As explained above, the refining industry is in the process of redesigning much of the current fuel slate to obtain desirable improvements in environmental performance. This task will continue because consumers desire higher-quality and cleaner-burning fuels. And our members want to satisfy their customers. We ask only that the programs be well-designed, well-coordinated, appropriately timed and cost-effective. The Committee can advance both the cause of cleaner fuels and preserve the domestic refining industry by adopting this principle as part of the nation's energy and environmental policies.

A healthy and diverse U.S. refining industry serves the nation's interest in maintaining a secure supply of energy products. Rationalizing and balancing our nation's energy and environmental policies will protect this key American resource. Given the challenges of the current and future refining environment, the nation is fortunate to retain a refining industry with many diverse and specialized participants. Refining is a tough business, but the continuing diversity and commitment to performance within the industry demonstrate that it has the vitality needed to continue its important work, especially with the help of a supply-oriented national energy policy.

RECOMMENDATIONS

We make the following recommendations to address concerns regarding fuel supplies, environmental regulations, and market issues.

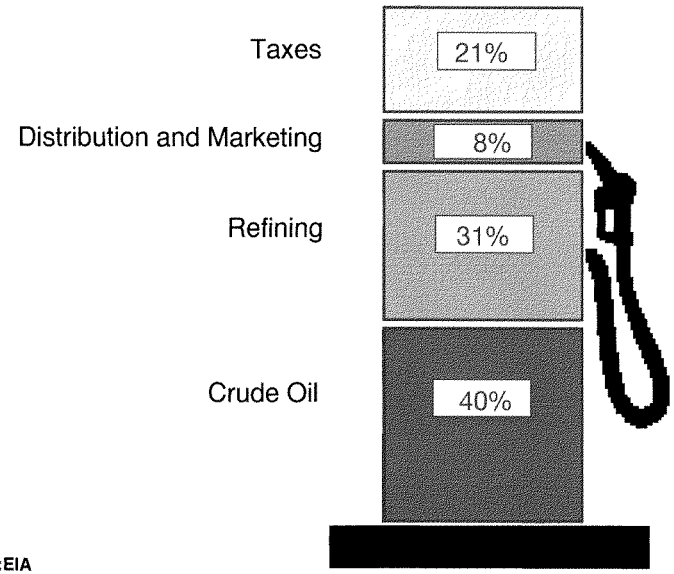
- Enacting the Conference Report on HR 6, a balanced and fair energy bill that brings energy policy into the 21st century, is the most important step needed to encourage new energy supply and streamline regulations.
- Public policymakers should balance environmental policy objectives and energy supply concerns in formulating new regulations and legislation.

- EPA should grant the California and New York requests to waive the 2% oxygen requirement for federal RFG. This will give refiners increased flexibility to deal with changing market conditions. It will also allow them to blend gasoline to meet the standards for reformulated gasoline most efficiently and economically, without a mandate.
- Congress should support the New Source Review reforms as well as other policy changes that encourage capacity expansions at existing refineries.
- Congress should enact legislation that streamlines the permitting process for refinery expansion projects, new refineries, and other key refining projects. Congress should consider declaring expansion of U.S. refining capacity a national priority, and provide guidelines for consideration of refining permits.
- Congress should be cautious about making any policy changes affecting "boutique fuels." More information is needed about boutique fuels, as well as future developments that may reduce the number of boutique fuels without legislative action.
- Policymakers must resist turning the clock backwards to the failed policies of the past. Experience with price constraints and allocation controls in the 1970s and 1980s demonstrates the failure of price regulation, which adversely impacted both fuel supply and consumer cost.

The industry looks forward to continuing to work with this Subcommittee, and thanks the Chairman for holding this important hearing. I would be glad to answer any questions raised by our testimony today.

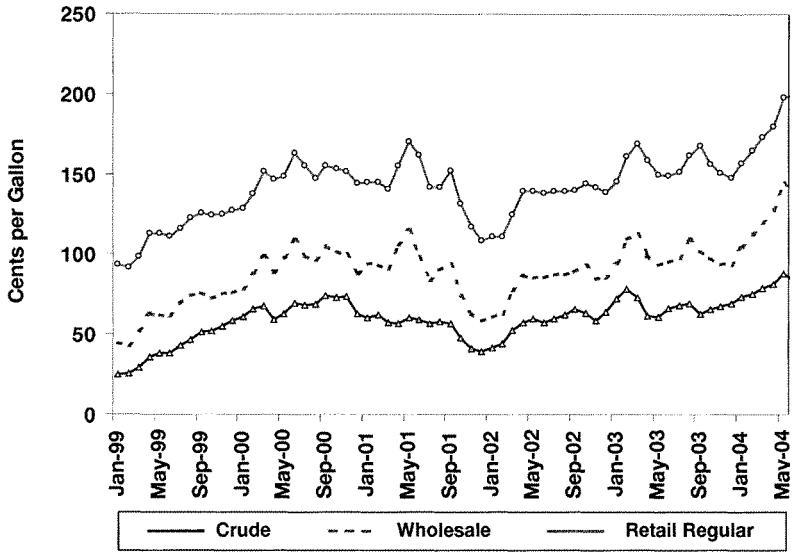
Attachment 1

What We Pay For in a Gallon of Regular Gasoline (May 2004) Retail Price: $1.98/gallon



Source:EIA

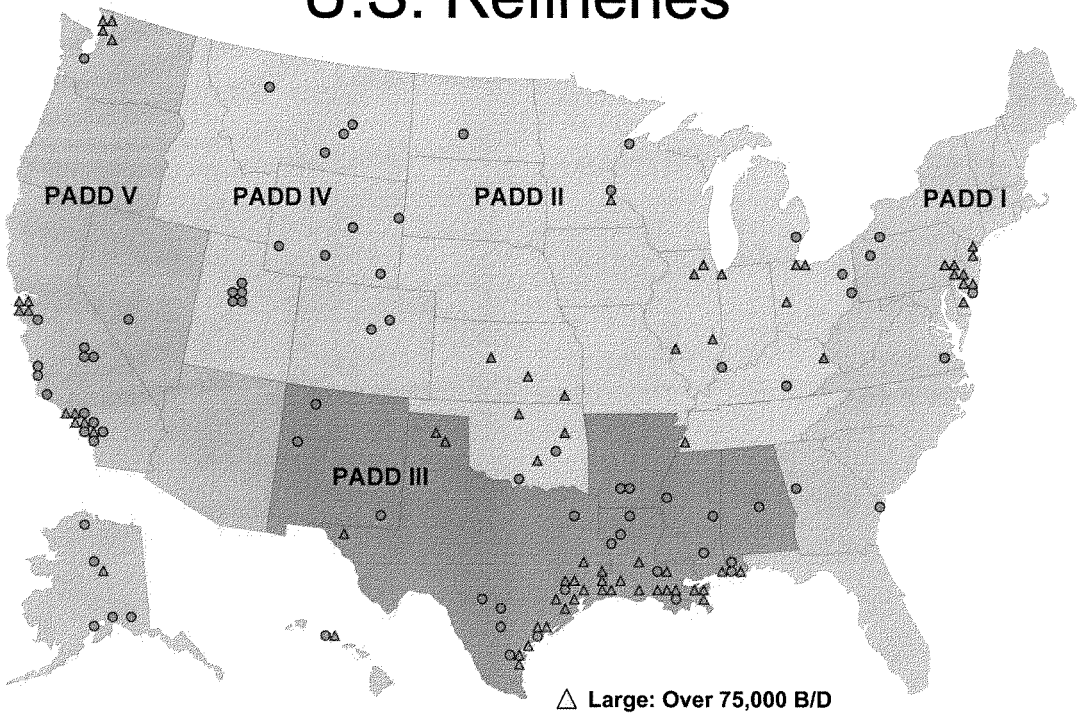
Gasoline Prices and Crude Oil Costs



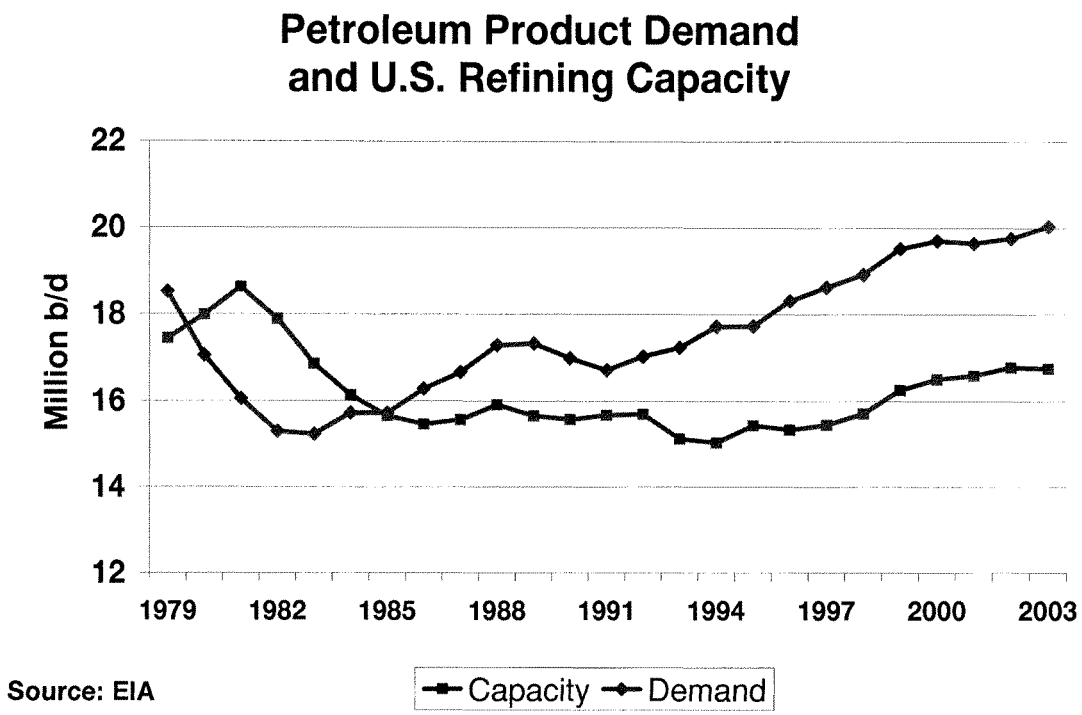
Source: EIA

Attachment 3

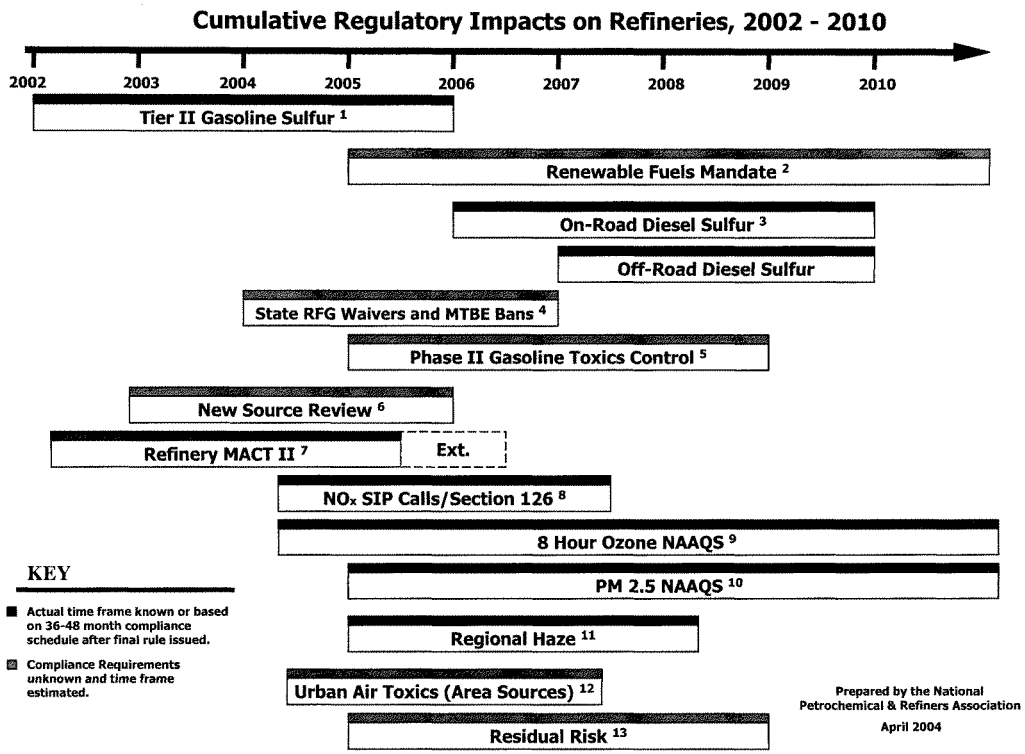
U.S. Refineries



EIA and NPRA


Petroleum Product Demand
and U.S. Refining Capacity
Million b/d
22
20
18
16
14
12
1979
1982
1985
1988
1991
1994
1997
2000
2003
Capacity
Demand

Source: EIA


Cumulative Regulatory Impacts on Refineries, 2002 - 2010
2002
2003
2004
2005
2006
2007
2008
2009
2010
Tier II Gasoline Sulfur 1
Renewable Fuels Mandate 2
On-Road Diesel Sulfur 3
Off-Road Diesel Sulfur
State RFG Waivers and MTBE Bans 4
Phase II Gasoline Toxics Control 5
New Source Review 6
Refinery MACT II 7
Ext.
NOx SIP Calls/Section 126 8
8 Hour Ozone NAAQS 9
PM 2.5 NAAQS 10
Regional Haze 11
Urban Air Toxics (Area Sources) 12
Residual Risk 13
KEY
Actual time frame known or based on 36-48 month compliance schedule after final rule issued.
Compliance Requirements unknown and time frame estimated.
Prepared by the National Petrochemical & Refiners Association
April 2004

1. Longer compliance time for refineries in Alaska and Rocky Mountain states as well as small refineries covered by the Small Business Regulatory Enforcement and Flexibility Act (SBREFA). Additional compliance time is available for these refineries if they produce ultra low sulfur highway diesel beginning in 2006.
2. Proposed energy bill (HR 6) includes an ethanol mandate which increases to 5 billion gallons in 2012.
3. Longer compliance time for small refiners covered by SBREFA.
4. Many state legislatures are considering bans on MTBE. CA, NY and CT bans effective January 2004. EPA is considering waiver requests from NY and CA for exemptions from the 2% oxygen mandate for RFG.
5. Phase II Mobile Source Air Toxics Rule to be proposed at the end of 2004. It is uncertain whether fuels and/or vehicles will be further regulated.
6. New Source Review reform (program changes and RMRR) is subject to litigation. Refiners face uncertainty in meeting regulatory requirements. Refiners support the reforms. EPA is continuing enforcement actions under the old rules.
7. Some facilities may delay compliance until May 2009 if they install a hydrotreater.
8. SIPs due by April 2005 for 21 states and the District of Columbia to address downwind NOx transport; compliance by May 2007.
9. Ozone non-attainment designations made April 2004. State Implementation Plans (SIPs) are due by June 2007. Compliance, depending upon classification, required between 2007 – 2021.
10. PM 2.5 non-attainment designations due at the end of 2004. SIPs due in the 2007-2008 timeframe.
11. Regional Haze SIPs due January 2008. Plans will include new plant controls for older facilities (built 1962- 1977) in 2011-2013 timeframe (BART controls) in areas with visibility problems.
12. Urban Air Toxics Strategy includes potential controls of gasoline loading facilities at refineries. Estimated compliance schedule.
13. Proposal is expected in 2004. A final rule is expected in 2005 with compliance by 2009.

Attachment 6
Source: API, 1997

Appendix A
PETROLEUM REFINING: APPLICABLE REGULATIONS

Name	Code of Federal Regulation (CFR) Cite	Effective Date
CLEAN AIR ACT (CAA)		
New Source Performance Standards (NSPSs)	40 CFR Part 60	
Subpart A: General Provisions	40 CFR Part 60	mid 1970s
Subpart Cb: Designated Facilities - Existing Sulfuric Acid Units	40 CFR Part 60	1991
Subpart D: Fossil-Fuel Fired Steam Generators Constructed After 8/17/71	40 CFR Part 60	1977
Subpart Da: Electric Utility Steam Generating Units Constructed After 9/18/78	40 CFR Part 60	1978
Subpart Db: Industrial-Commercial-Institutional Steam Generating Units	40 CFR Part 60	1987
Subpart Dc: Small Industrial-Commercial-Institutional Steam Generating Units	40 CFR Part 60	1990
Subpart H: Sulfuric Acid Units	40 CFR Part 60	1977
Subpart J: Petroleum Refineries	40 CFR Part 60	1978
Subpart K: Storage Vessels for Petroleum Liquids Constructed, Reconstructed or Modified between 6/11/73 and 5/19/78	40 CFR Part 60	1977
Subpart Ka: Storage Vessels for Petroleum Liquids Constructed, Reconstructed or Modified between 5/18/78 and 7/23/84	40 CFR Part 60	1980
Subpart Kb: Volatile Organic Liquid Storage	40 CFR Part 60	1987
Subpart GG: Stationary Gas Turbines	40 CFR Part 60	1978
Subpart UU: Asphalt Processing and Roofing Manufacturing	40 CFR Part 60	1982
Subpart VV: Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI)	40 CFR Part 60	1983
Supart XX: Bulk Gasoline Terminals	40 CFR Part 60	1983
Subpart GGG: Equipment Leaks of VOC in Petroleum Refineries	40 CFR Part 60	1984
Subpart III: VOC Emissions for SOCMI Air Oxidation Unit Processes	40 CFR Part 60	1990
Subpart NNN: VOC Emissions for SOCMI Distillation Processes	40 CFR Part 60	1990
Subpart QQQ: VOC Emissions for Petroleum Refinery Wastewater Systems	40 CFR Part 60	1988
Subpart RRR: SOCMI Reactor Processes	40 CFR Part 60	1993
National Emission Standards for Hazardous Air Pollutants (NESHAPs)		
Subpart A: General Provisions	40 CFR Part 61	1973
Subpart J/V: Equipment Leaks (Fugitive Emission Sources) of Benzene	40 CFR Part 61	mid 1980s
Subpart M: Asbestos	40 CFR Part 61	1984
Subpart Y: Benzene Emissions from Benzene Storage Vessels	40 CFR Part 61	mid 1980s
Subpart BB: Benzene Emissions from Benzene Transfer Operations	40 CFR Part 61	mid 1980s
Subpart FF: Benzene Waste Operations	40 CFR Part 61	1993

Name	Code of Federal Regulation (CFR) Cite	Effective Date
NESHAPs for Source Categories		
Subpart A: General Provisions	40 CFR Part 63	1994
Subpart B: Control Technology Determination	40 CFR Part 63	1994
Subpart F: SOCMI	40 CFR Part 63	1994
Subpart G: SOCMI Process Vents, Storage Vessels, Transfer Operations, and Wastewater	40 CFR Part 63	1994
Subpart H: Equipment Leaks	40 CFR Part 63	1994
Subpart I: NESHAP for Organic Hazardous Air Pollutants (HON); Certain Processes Subject to the Negotiated Regulation for Equipment Leaks	40 CFR Part 63	1994
NESHAP for HON (partially under stay pending reconsideration for compressors, surge control vessels, and bottom receivers)	40 CFR Part 63	4/22/94
Subpart Q: Industrial Cooling Towers	40 CFR Part 63	1994
Subpart R: Stage I Gasoline Distribution Facilities	40 CFR Part 63	12/14/94
Subpart T: Halogenated Solvent Cleansing (MACT)	40 CFR Part 63	12/2/94
Subpart Y: NESHAP for Marine Tank Vessel Loading and Unloading Operations (MACT)	40 CFR Parts 9, 63	mid 1995
Subpart CC: NESHAP for Petroleum Refining — Phase I (MACT)	40 CFR Parts 9, 60, 63	mid 1995
Stack Height Provisions	40 CFR Part 51, Subpart G	1986
Control Technology Guidelines (CTGs)		
Petroleum Liquid Storage In External Floating Roof Tanks	40 CFR Part 52	1978
Petroleum Liquid Storage in Fixed Roof Tanks	40 CFR Part 52	1977
Petroleum Refinery Equipment Leaks	40 CFR Part 52	1978
Refinery Vacuum Producing Systems, Wastewater Separators and Process Unit Turnarounds	40 CFR Part 52	1977
SOCMI Air Oxidation Processes	40 CFR Part 52	1984
SOCMI Distillation Operations and Reactor Processes	40 CFR Part 52	1993
Tank Truck Gasoline Loading Terminals	40 CFR Part 52	1977
Fuels		
Fuel and Fuel Additives:		
Registration Requirements	40 CFR Part 79	5/27/94
Interim Requirements for Deposit Control Gasoline Additives	40 CFR Part 80	1/1/95
Reid Vapor Pressure Limitation	40 CFR Part 80	late 1980s
Oxygenated Fuel Requirement	40 CFR Part 80	1992
Lead Phaseout	40 CFR Part 80	12/31/95
Reformulated Gasoline	40 CFR Part 80	1/1/95
Low Sulfur Diesel	40 CFR Part 85	1993
Permits		
State Operating Permit Program - Title V (Revised 8/29/94)	40 CFR Part 70	1992
Prevention of Significant Deterioration (new sources in attainment areas) and New Source Review (new sources in non-attainment areas); LAER requirements (existing source)	40 CFR Part 52	1978
Stratospheric Ozone	40 CFR Part 82	1990-2015

Name	Code of Federal Regulation (CFR) Cite	Effective Date
Acid Rain Provisions	40 CFR Parts 72, 73, 75, 77, 78	ongoing
Nitrogen Oxides Emission Reduction Program	40 CFR Part 76	1994
CLEAN WATER ACT (CWA)		
Discharge of Oil: Notification Requirements	40 CFR Part 110	1987
Designation of Hazardous Substances	40 CFR Part 116	1978
Notice of Discharge of a Reportable Quantity	40 CFR Part 117	late 1970s
Spill Prevention, Control, and Countermeasures (SPCC) Requirements for Oil Storage	40 CFR Part 112	mid 1970s
General Provisions for Effluent Guidelines and Standards	40 CFR Part 401	1974
Toxic Pollutant Effluent Standards	40 CFR Part 129	1977
Effluent Guidelines and Categorical Pretreatment Standards	40 CFR Part 419	late 1970s - mid 1980s
Water Quality Standards for Toxic Pollutants	40 CFR Part 131	2/5/93
General National Pretreatment Standards	40 CFR Part 403	early 1980s
Great Lakes Water Quality Guidance	40 CFR Parts 9, 122, 123, 131, 132	early 1995
NPDES		
Stormwater Application, Permit, and Reporting Requirements Associated with Industrial Activities	40 CFR Part 122	5/4/92
Permit	40 CFR Parts 121-125	early 1980s
OIL POLLUTION ACT (OPA)		
Natural Resource Damage Assessments (NRDA) under National Oceanic and Atmospheric Administration	15 CFR Part 990	early 1996
Response Plans for Marine Transportation-Related Facilities (interim final rule)	33 CFR Parts 150, 154	1/19/93
Oil Pollution Prevention; Non-Transportation-Related Onshore Facilities	40 CFR Parts 9, 112	8/30/94
RESOURCE CONSERVATION AND RECOVERY ACT (RCRA)		
Non-Hazardous Waste Requirements (Subtitle D)	40 CFR Parts 256, 257 (Federal guidelines for state/local requirements)	late 1970s, early 1980s
Subtitle C Requirements		
General Requirements for Hazardous Waste Management	40 CFR Part 260	late 1970s
Identification and Listing of Hazardous Wastes and Toxicity Characteristics	40 CFR Part 261	late 1970s
Standards Applicable to Generators of Hazardous Wastes		
Subpart A: General Provisions	40 CFR Part 262	early 1980s
Subpart B: Shipping Manifest	40 CFR Part 262	early 1980s
Subpart C: Packaging, Labeling, Marking, and Placarding	40 CFR Part 262	early 1980s
Subpart D: Recordkeeping and Reporting	40 CFR Part 262	early 1980s
Subparts E & F: Exports and Imports	40 CFR Part 262	early 1980s
Standards for Owners and Operators of Hazardous Waste Treatment, Storage, and Disposal Facilities (and generally for Interim Status)		
Subparts A & B: General Provisions & Facility Standards	40 CFR Part 264 (265)	early 1980s
Subparts C & D: Preparedness, Prevention, & Emergency Plans	40 CFR Part 264 (265)	early 1980s
Subpart E: Recordkeeping/Reporting Requirements	40 CFR Part 264 (265)	early 1980s

Name	Code of Federal Regulation (CFR) Cite	Effective Date
Subpart F: Releases from Units	40 CFR Part 264	early 1980s
Subpart F: Groundwater Monitoring Requirements (Interim Status only)	40 CFR Part 265	early 1980s
Subpart G: Closure and Post-closure Requirements	40 CFR Part 264 (265)	1986
Subpart H: Financial Responsibility Requirements	40 CFR Part 264 (265)	early 1980s
Subparts I, J, K, & L: Use and Management of Containers, Tank Systems, Surface Impoundments, & Waste Piles	40 CFR Part 264 (265) *	early 1980s (except tanks: 1986)
Liners and Leak Detection for Hazardous Waste Land Disposal Units	40 CFR Part 264 (265)	1992
Double Liners and Leachate Collection Systems for Hazardous Waste Disposal Units	40 CFR Parts 144, 264 (265)	1992
Subparts M, N, & O: Land Treatment, Landfills, & Incinerators	40 CFR Part 264 (265)	early 1980s
Subpart S: Corrective Action	40 CFR Part 264 (265)	1985 (1993)
Subparts AA, BB, & CC: Air Emission Standards for Process Vents; Equipment Leaks; & Tanks, Surface Impoundments, and Containers	40 CFR Part 264 (265)	
Phase I	40 CFR Part 264 (265)	1990
Phase II	40 CFR Part 264 (265)	1994
Standards for the Management of Specific Hazardous Wastes	40 CFR Part 266	1985
Land Disposal Restrictions	40 CFR Part 268	1986
Phase I: Contaminated Debris and Newly Identified Wastes, F037 and F038 Petroleum	40 CFR Parts 148, 268	1992, 1993
Phase II: Set Treatment Standards (BDAT) for TC Wastes and Establish Universal Treatment Standards	40 CFR Parts 148, 268	1994
Permits	40 CFR Parts 270, 271, 272	1980s
Standards for the Management of Used Oil: Used Oil Destined for Recycling	40 CFR Part 279	1993
Underground Storage Tanks: Technical Standards and Corrective Action	40 CFR Part 280	1988
SAFE DRINKING WATER ACT (SDWA)		
Underground Injection Control Regulations	40 CFR Parts 144, 146	12/16/93
SUPERFUND (CERCLA)		
Natural Resource Damage Assessments (also under CWA)	43 CFR Part 11	3/17/94
Reportable Quantities Releases (Notification to National Response Center)	40 CFR Part 302	mid 1980s
Extremely Hazardous Substances (EHSs) Emergency Planning	40 CFR Part 355	1987
EHS Release Notification (Notification to State Emergency Response Commission, Local Emergency Response Commission) and Follow-up	60 CFR Part 355	mid 1980s
Community Right-To-Know		
Hazardous Chemicals (Material Safety Data Sheet Chemicals) Inventory Reporting	40 CFR Part 370	late 1980s
Toxic Chemical Release Reporting	40 CFR Part 372	1988
Expansion of TRI List	40 CFR Part 372	11/30/94

Name	Code of Federal Regulation (CFR) Cite	Effective Date
TOXIC SUBSTANCES CONTROL ACT (TSCA)		
General Provisions	40 CFR Part 702	1982
Reporting and Recordkeeping Requirements	40 CFR Parts 704, 710	1988, late 1970s
Chemical Information Rule	40 CFR Part 712	1982
Health & Safety Data Reporting	40 CFR Parts 716	.1986
Premanufacture Notification (and Exemptions)	40 CFR Parts 720 (723)	1983 (1995)
Significant New Uses	40 CFR Part 721	1988
Chromium Comfort D Cooling Towers	40 CFR Part 749	1990
Rules for Controlling Polychlorinated Biphenyls	40 CFR Part 761	1979
Asbestos-Containing Products Labelling Requirements	40 CFR Part 763	1979

Update of Appendix A[1]

Name	Code of Federal Regulation (CFR) Cite
CLEAN AIR ACT (CAA)	
New Source Performance Standards	40 CFR Part 60
Subpart CCCC: Commercial and Industrial Solid Waste Incineration Units	40 CFR Part 60
NESHAPS for Source Categories	40 CFR Part 63
Subpart EEE: Hazardous Waste Combustors	40 CFR Part 63
Subpart UUU: Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II)	40 CFR Part 63
Subpart EEEE: Organiz Liquids Distribution (Non- Gasoline)	40 CFR Part 63
Subpart FFFF: Miscellaneous Organic Chemical Manufacturing	40 CFR Part 63
Subpart YYYY: Stationary Combustion Turbines	40 CFR Part 63
Subpart GGGGG: Site Remidiation	40 CFR Part 63
Subpart LLLLL: Asphalt Roofing and Asphalt Processing	40 CFR Part 63
Subpart DDDDD: Industrial/Commerical/Institutional Boilers and Process Heaters	40 CFR Part 63
Subpart ZZZZZ: Reciprocating Internal Combustion Engines	40 CFR Part 63
Fuels	40 CFR Part 80
Subpart H: Tier II Gasoline Sulfur	40 CFR Part 80
Subpart I: Ultra Low Sulfur Highway and Nonroad Diesel	40 CFR Part 80
Subpart J: Mobile Source Air Toxics	40 CFR Part 80

[1] As of June 2004 Source: NPRA

Mr. HALL. Thank you, Mr. Slaughter.

The Chair recognizes Mr. Blakeman Early, Environmental Consultant, American Lung Association. Mr. Early, we recognize you for 5 minutes, sir.

STATEMENT OF A. BLAKEMAN EARLY

Mr. EARLY. Thank you, Mr. Chairman and members of the committee. I am Blakeman Early, and I am here on behalf of the Lung Association.

The Clean Air programs that we believe most affect the refining industry are the Reformulated Gasoline Program and the low-sulfur requirements for gasoline, on-road diesel, and off-road diesel fuel. These clean fuels are a cornerstone of the Clean Air Act. I will confine my remarks to these programs.

RFG has been shown by EPA in California to be a cost-effective program to reduce vehicle emissions that contribute to ozone, and reduce toxic air pollution from vehicles by 30 percent. Low-sulfur gasoline, on-road diesel, and non-road diesel requirements issued by both the Clinton and Bush Administrations are key to enabling a new generation of emission controls everything from SUVs to diesel trucks to earth movers that will reduce smog, fine particulate air pollution and toxic air pollution, and save tens of thousands of lives, heart attacks, respiratory-related hospitalizations, and reduce thousands of asthma attacks among children each and every year.

The benefits from these low-sulfur fuel programs are enormous, calculated to approximate $24, $51, and $53 billion each year for those three respective programs when they are fully implemented. Any attempt to modify these rules at this juncture without thoroughly evaluating the risks of disrupting these programs in ways that could reduce or delay the large public health benefits we need them to be deliver must be scrutinized very carefully. Those who propose these changes bare a very heavy burden of showing the need and demonstrating the benefit. This is because air pollution still threatens millions of Americans. The American Lung Association found 441 counties, home to 136 million people, have monitored unhealthy levels of either ozone or particulate air pollution.

We believe that should Congress choose to change the law or gasoline policy, it should do so in ways that make it easier for areas with dirty air to adopt clean fuels programs, and not lock in the use of dirtier conventional fuels.

In mid June, many members of this committee voted for H.R. 4545, the Gasoline Price Reduction Act of 2004. This bill would violate the principal I just espoused. The bill is unneeded, overly broad, and can be used in ways that would reduce public health protection already adopted in States' implementation plans to reduce air pollution.

The bill also would limit future adoption of these needed fuel requirements for all fuels by States based on arbitrary limits that would not alleviate gasoline price or supply concerns.

There is no evidence that current clean fuel programs significantly influence current gasoline price increases. Prices for both clean fuels and conventional gasoline have risen at the same rate broadly across the entire Nation, and prices for clean fuels generally have not risen faster for clean fuels than for conventional

gasoline. In some cases, conventional gasoline is the same or more expensive than RFG, although this has varied in recent weeks. I have two charts in my testimony that illustrate my point.

The one clean fuel requirement that we believe does contribute to price volatility is the Federal oxygen requirement. The one thing the Bush Administration should do is grant California's request for an oxygen waiver. Granting the waive would improve air quality and reduce gasoline prices in California, and perhaps in other parts of the country. EPA has been avoiding a decision on this urgent matter and treating it as a routine matter.

I attached to my testimony a letter signed by nine health and environmental organizations urging Administrator Leavitt to grant the waiver immediately. This is a priority matter that could make a real difference this summer, Mr. Chairman. And I will take any questions you may have for me. Thank you.

[The prepared statement of A. Blakeman Early follows:]

PREPARED STATEMENT OF A. BLAKEMAN EARLY ON BEHALF OF THE AMERICAN LUNG ASSOCIATION

Mr. Chairman and members of the committee, my name is A. Blakeman Early. I am pleased to appear today on behalf of the American Lung Association. Celebrating its 100th anniversary this year, the American Lung Association has been working to promote lung health through the reduction of air pollution for over thirty years. I am here today to discuss elements of the Clean Air Act that impact the oil refining industry and gasoline prices.

Clean Fuels Are a Cornerstone of the Clean Air Act

The Clean Air Act programs that we believe most affect the refining industry are the Reformulated Gasoline Program (RFG) and the low-sulfur requirements for gasoline, on-road diesel, and off-road diesel fuel. We recognize that there are important stationary source requirements of the Clean Air Act that impact the refining industry. However, because of their importance, I will limit my comments to the most significant fuel requirements of the law.

Reformulated Gasoline

As has been demonstrated in California and across the nation, reformulated gasoline can be an effective tool in reducing both evaporative and tailpipe emissions from cars and trucks that contribute to smog. Based on separate cost effectiveness analyses by both EPA and California, when compared to all available emissions control options, reformulated gasoline (RFG) is a cost-effective approach to reducing the pollutants that contribute to smog.[1] Compared to conventional gasoline, RFG has also been shown to reduce toxic air emissions from vehicles by approximately 30 percent.[2] A study done by the Northeast States for Coordinated Air Use Management, an organization of state air quality regulators, estimated that ambient reduction of toxic air pollutants achieved by RFG translates into a reduction in the relative cancer risk associated with conventional gasoline by a range of 18 to 23 percent in many areas of the country where RFG is used.[3]

The benefits from RFG accrue from evaporative and tailpipe emissions reductions from vehicles on the road today, as well as from non-road gasoline powered engines, such as lawn mowers. They begin as soon as the fuel is used in an area. As with most Clean Air Act programs, the RFG program has cost less than estimated and the emissions benefits have been greater than expected or required by law. It is no wonder that RFG or other clean gasoline programs are in use in 15 states, according to EPA.

Low Sulfur Conventional Gasoline

This year begins the phase in of sulfur reduction requirements for all gasoline, which will be fully implemented by the end of 2006. These requirements derive from

[1] U.S. Environmental Protection Agency, Regulatory Impact Analysis, 59 FR 7716, docket No. A-92-12, 1993.

[2] Report of the Blue Ribbon Panel on Oxygenates, September 1999, pp.28-29.

[3] Relative Cancer Risk of Reformulated Gasoline and Conventional Gasoline Sold in the Northeast, August 1998, p. ES-6, found at www. Nescaum.org.

the Tier 2/Gasoline Sulfur rule issued during the Clinton Administration. This program is even more significant than the RFG program because the lower sulfur levels required in conventional gasoline will reduce tailpipe emissions from vehicles and other engines used today not just in RFG areas, but virtually across the nation. More importantly, the limit on sulfur in gasoline enables the use of very sophisticated technology on a new generation of gasoline- powered vehicles (including SUVs) that will generate very low rates of tailpipe emissions. These emissions reductions will grow as the new cleaner vehicles replace older dirtier ones. This program is so important to offset the growth in vehicle emission attributable to the fact that each year more people are driving more vehicles more miles than ever before. The Tier 2/Gasoline Sulfur requirements will replace and unify varying sulfur limits found in so-called "boutique" fuels standards as well as RFG. In other words, all gasoline sold in the nation will meet the same sulfur limits, except in California.

The estimated benefits from the Tier2/Gasoline Sulfur rule will be enormous. EPA estimates that when fully implemented, the program will reduce premature mortality, hospital admissions from respiratory causes and a range of other health benefits that have a monetized benefit of over $24 billion **each year**.[4] The actual benefits will likely be higher if history is any guide in these matters.

At this point I am going to say something unexpected. It is important to note that with respect to the RFG program and the Tier 2 sulfur reduction program the refining industry is getting the job done and at a cost below what it and others predicted. Moreover, refiners are reducing toxic emissions from RFG by a significantly larger percentage than the minimum required by the Clean Air Act Some refiners, such as BP have met low sulfur goals ahead of legal requirements and are using their success as a marketing tool and even have received public recognition from American Lung Association state affiliates. We at the American Lung Association want to give credit where credit is due.

Low Sulfur On-Road Diesel Fuel

While the Tier 2 rule was issued by the Clinton Administration, the value of clean fuels has not been lost on the Bush Administration. The Heavy Duty Diesel Engine/Diesel Fuel rule was first issued in the Clinton Administration and was reaffirmed by the Bush Administration in January 2000. Like the Tier 2 rule, this rule will provide immediate benefits from reductions of both NOx and particulate emissions from diesel fueled vehicles on the road today but also enable the application of new technology to a new generation of heavy duty diesel engines used in trucks and buses in the future that will reduce particle and NOx emissions from the vehicles by 90%. The sulfur reduction requirements for on-road diesel fuel are phased in beginning in 2007.

Diesel emissions are an important contributor of NOx, a precursor of smog. More importantly, heavy-duty diesel emissions generate a large amount of fine particle air pollution that is associated with premature mortality and cancer. The EPA estimates that when fully implemented, the HD Diesel Engine/Diesel Fuel rule will provide health benefits that approximately double the Tier 2 rule at a monetized calculation of nearly $51 billion **each year**.[5]

Finally, in further recognition of the importance diesel emissions play as a contributor to both smog and fine particle pollution, the Bush Administration just issued in May a new Off-Road Diesel Engine/Diesel Fuel rule Through phased reductions of sulfur in off-road diesel fuel this rule will achieve immediate emissions reductions from a diverse group of diesel engines used in construction, electricity generation and even trains and marine vessels. The clean fuel requirements of this rule, too, will enable a new generation of much cleaner off-road diesel engines which will result in lower diesel emissions far into the future as older engines are replaced.

My understanding is that the estimate of health benefits from this rule will be even greater than the HD Engine/Diesel Fuel rule in large part because this category of engines and their fuel have been under regulated in comparison to other engine sectors. EPA projects that, when fully implemented, health benefits to include: 12,000 fewer premature deaths, 15,000 fewer heart attacks, 6,000 fewer emergency room visits by children with asthma, and 8,900 fewer respiratory-related hospital admissions **each year**.[6]

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[4] Tier 2/Sulfur Regulatory Impact Analysis, December 1999, p. VII-54.

[5] HD Engine/Diesel Fuel Regulatory Impact Analysis, January 18, 2001, p. VII-64.

[6] EPA Regulatory Announcement: Public Health and Environmental Benefits of EPA's Proposed Program for Low-Emission Nonroad Diesel Engines and Fuel. April 2003.

We Oppose Changes to Clean Fuels Programs That Weaken or Delay Emissions Reductions

Each of the regulations implementing the clean fuels programs and requirements were the product of a broad, lengthy and public process that ultimately reached a delicate political and substantive compromise. No party got everything it wanted. Each rule provides large and critical emissions reductions needed to protect public health. **Any attempt to modify these rules at this juncture without thorough evaluation risks disrupting these programs in ways to could reduce or delay the large public health benefits we need them to deliver. Such changes also risk penalizing those refiners who have made the commitment to meet the requirements of these programs, some times earlier than required. Those who propose changes bear a heavy burden of showing the need and demonstrating the benefit.**

Air Pollution Still Threatens Millions of Americans

Although we have made important progress in reducing air pollution, the battle is far from being won. This is true in part due to improved research in recent years which indicates that exposure to lower levels of smog over longer periods can have adverse health effects. The adverse impact of smog is being magnified also by the increase in the number of people with asthma. Smog is an important trigger of asthma attacks. New research has also revealed the lethality of so-called fine particle air pollution not only among those previously known as vulnerable such as people with asthma or chronic lung disease, but also among those with cardiovascular disease. This research is the foundation of the establishment of the eight-hour NAAQS for ozone and the NAAQS for PM 2.5 promulgated in 1997. Additional research since then has reinforced the need for these standards.[7]

The senate received testimony from Dr. George Thurston, a leading air pollution researcher, just a few weeks ago demonstrating that the progress in reducing eight-hour levels of ozone has stalled in recent years. A graph in his testimony, based on EPA monitoring data shows the decline in eight-hour ozone levels to be essentially flat between 1996 and 2002.[8]

At the end of April, the American Lung Association released its State of the Air 2004 report identifying all the counties nation-wide with air pollution monitors that monitored unhealthy levels of smog and fine particles over the 2000-2002-time period. The report found that counties that are home to nearly half the U.S. population, 136 million people, experienced multiple days of unhealthy ozone each year. The report further found that over 81 million Americans live in areas where they are exposed to unhealthful short-term levels of fine particle air pollution. In all, the report found that 441 counties, home to 55% of the U.S. population have monitored unhealthy levels of either ozone or particle pollution. Among those vulnerable to the effects of air pollution living in these counties include 29 million children, 10 million adults and children with asthma and nearly 17 million people with cardiovascular disease.[9] As impressive as these numbers may seem, it is undoubtedly an under estimate of the nature of the air pollution problem in this country because far from every county has a monitor for either smog or particle pollution.

We Need Greater Use of Clean Fuels in Areas with Unhealthy Levels of Smog and Particulate Air Pollution

As you know, on April 15 EPA designated all or part of 474 counties in non-attainment with the eight-hour National Ambient Air Quality Standard (NAAQS) for Ozone. Last week EPA proposed to designate approximately 233 counties in non-attainment for the fine particle or PM 2.5 NAAQS to take effect in December. These areas will be required to evaluate and select emissions reduction strategies that, in combination with the federal programs aimed at air pollution transported over long distances, will enable them to achieve the eight-hour standard and fine particle standards. The American Lung Association believes that many new non-attainment areas may want to adopt a clean fuels program using either RFG or a low volatility alternative or obtaining low sulfur diesel sooner than required by the regulations previously described. **We believe that should congress choose to change the law or otherwise influence gasoline policy, it should do so in a way that makes it easier for areas that exceed air pollution standards to adopt clean**

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[7] See Annotated Bibliography of Ozone Health Studies, January 27, 2003 and Fact Sheet on Fine Particles, May 2003 at www.cleanairstandards.org a website of the American Lung Association

[8] Statement of George D. Thurston, Sc.D., before the Senate Environment and Public Works Committee, April 1, 2004, p.6.

[9] State of the Air: 2004, pp. 5-11 at www.lungusa.org

fuels programs and not "lock in" the use of dirtier conventional fuels. We need clean fuels programs to be broadly adopted to obtain clean air and protect the public health as soon as possible.

Legislation that violated this principle was recently voted on in the House and garnered the support of many members of this committee. H.R. 4545, The Gasoline Price Reduction Act of 2004, was introduced by Mr. Blunt and, remarkably, was not the subject of a hearing or mark-up by this committee. The bill would have given EPA broad authority to EPA to waive state fuel or fuel additive SIP measures adopted under section 211(c)(4) of the Clean Air Act based on a "significant fuel disruption." It would also, among other provisions, limit the adoption of fuel or fuel additive SIP requirements by any area in the future if they exceeded a cap based on such requirements in effect on June 1, 2004. The American Lung Association opposed several elements of this legislation.

With regard to the waiver provision in Section 2 of the bill, it is not clear that current authority, which allows for EPA to exercise enforcement discretion, is insufficient in times of true disruption problems. As members of the committee may know, such discretion already has been exercised with respect to RFG in Chicago/Milwaukee, St. Louis, and Phoenix. The bill does not define "significant supply disruption," limit the time period for the waiver, or require that offsets of lost emissions reductions be obtained in order to avoid air quality standards exceedences or to prevent disruption of timely attainment of air quality standards. In sum, Section 2 of the bill is unneeded, overly broad and could be used in ways that would reduce public health protections already adopted into law in state SIPS.

Section 3 of the Blunt bill would operate as a limitation to the future adoption of fuel or fuel additive requirement or limitation in a state SIP based on the arbitrary number of such requirements in existence on June 1, 2004. This limitation would apply to all fuel and fuel additives requirements regardless of their need and even if such requirement placed no burden on gasoline price or supply. For instance, diesel fuel specifications limiting sulfur in diesel fuel used by ocean vessels or airplanes would be barred even though such requirements may have no direct impact on gasoline price or supply. Of importance to some members of this committee, a state could not adopt bio-diesel requirements into its SIP as part of an ozone or fine particle reduction strategy if it exceeded the artificial cap of Section 3. Lastly, this provision would provide a litigation hook for any interest to challenge an adopted fuel SIP requirement even if such challenge were not in the best interest of public health, lower gasoline prices, or improved gasoline supply. I have heard many members of this committee express the need to reduce the amount of litigation brought in this country. Section 3 might well result in more lawsuits, not fewer.

At a minimum, H.R. 4545 needs a thorough review and mark-up by this committee before further consideration by the House. The American Lung Association would hope to convince you that this legislation is not needed and counter-productive to the effort to find ways to improve air quality using fuel strategies while not jeopardizing the affordability of our fuels. I have attached to my testimony a letter in opposition to H.R. 4545 signed by twelve environmental, health and air pollution control organizations.

There is No Evidence That Current Clean Fuels Programs Significantly Influence Current Gasoline Price Increases

As is customary when gasoline prices spike, some have recently suggested that the clean fuels programs, often referred to as "boutique fuels" are responsible. While it appears that clean gasoline programs in both California and the Chicago/Milwaukee area have contributed to temporary price spikes in the past, we believe there has been little evidence presented publicly demonstrating that clean fuels programs across the country are contributing in any significant way to today's high gasoline prices. Indeed, the evidence would suggest that systemic influences in gasoline production and marketing are the reason gasoline prices are as high as they are today. We believe this to be the case because: 1) gasoline prices have increased nation-wide, 2) conventional and clean gasoline prices are rising at the same rate, 3) in some areas, conventional gasoline is priced at or near the price of clean gasolines, 4) refiners are posting higher profits than they did a year ago when prices were lower.

Both conventional and clean fuels have risen in price $.30 cents a gallon or more from a year ago. This increase has occurred in virtually all parts of the country regardless of where their gasoline comes from or who makes it. More significantly, the increases in price for conventional gasoline and clean gasolines have pretty much been the same. Attached to the end of my testimony I have prepared two unscientific charts that illustrates my point. I believe a more comprehensive examination

of the data will support my conclusions. I encourage the committee to ask DOE or EPA to conduct such an examination.

If the cost of producing clean gasoline were a major factor, the prices of these fuels would be rising at a faster rate. As my Chart A shows, this does not appear to be happening. What is noteworthy is that in the West, the "rack" or wholesale cost of conventional gasoline in the states that border California, which has the most stringent fuel requirements in the country, has risen more than in California. In Las Vegas conventional gasoline is actually more expensive than the average rack price in California and Reno is almost the same. Portland also has the same expensive conventional gasoline. In New York the RFG sold in the New York City/Connecticut area will for the first time use the same low volatility blend-stock used in the Chicago/Milwaukee market because of new state MTBE bans. Yet the price of conventional gasoline in Albany has risen at the same rate and maintains the same price spread as a year ago. Note in Chart A that Atlanta, which has required the use of a low volatility; low sulfur "boutique" for several years has experienced a price increase no greater than Macon, which uses conventional gasoline. Even when Atlanta introduced RFG with ethanol, its price increase is only three cents greater (See Chart B). Atlanta's fuel prices have consistently been below the national average price for conventional gasoline for reasons that remain a mystery. Since I collected the prices in Chart A, there has been much shifting in gasoline prices (See Char B) but the pattern has remained basically the same with some exception. In some areas the spread between RFG and conventional fuels is greater, notably the Portland and Las Vegas.

The point is that the many other factors that impact gasoline price, lead by unsustainable growth in demand and the price of crude oil which is currently at or near $40 per barrel have historically driven price and do so today. Clean fuel requirements have an insignificant impact in comparison.

The Bush Administration Should Grant the California Oxygen Waiver Request

The one fuel requirement which operates as an exception to my testimony provided above is the federal oxygen requirement applicable to RFG in California As you know, California has been seeking a waver of the 2% oxygen requirement applicable to federal RFG sold in California since 1999. The state has provided impressive data showing that because California has banned MTBE and must use ethanol in every gallon of RFG sold in the state, emissions of soot and smog forming nitrogen oxides are higher compared to the use of California's Cleaner Burning Gasoline (CBG) without minimum oxygen levels met with ethanol. By all accounts, granting California's waiver request would increase the flexibility California refiners have to produce CBG and could lower gasoline prices modestly. The reduced need for ethanol in California, the largest in the nation, might even lower the cost of gasoline containing ethanol sold elsewhere across the country, such as in New York and Connecticut that have also banned MTBE. Yet EPA is not even giving California's request priority consideration even though it has been under court order since last October. A letter urging expedited approval of California's waiver request signed by nine health environmental organizations was sent to Administrator Leavitt last week. I have attached the letter to my testimony.

If President Bush would order Administrator Leavitt to grant California's oxygen waiver request tomorrow, it would result in improved air quality an immediate reduction in gasoline prices in California and perhaps other parts on the nation.

Finally, I must note that across the board, refiners are making more money this year than a year ago. The popular media has been filled with stories over the record high profits refiners earned in the first quarter of 2004. The cost of gasoline is high because demand continues to grow at an unsupportable pace. Refiners could make money by producing more gasoline, but selling it at a lower price. It is pretty obvious that they are not choosing this strategy. It is apparently easier and more profitable to maintain a larger gap between demand and supply and earn higher profits on a lower level of production.

CHART A

RETAIL PRICE RISE COMPARISON OF CG & RFG

(Cents per gallon)

	5/6/03	5/6/04	Change
Chicago (RFG)	158.10	201.30	+43.20

CHART A—Continued

RETAIL PRICE RISE COMPARISON OF CG & RFG

(Cents per gallon)

	5/6/03	5/6/04	Change
Champaign (CG)	141.70	186.00	+44.30
St. Louis (RFG)	137.80	183.60	+45.80
Milwaukee (RFG)	156.40	196.40	+40.00
Madison (CG)	150.20	192.00	+41.80
Allentown (CG)	147.80	179.30	+31.50
Philadelphia (RFG)	160.30	182.60	+22.30
Atlanta (GG-low S, Low RVP)	133.10	173.70	+40.60
Macon (CG)	129.80	169.50	+39.70
Denver/Boulder (CG-low RVP)	144.70	182.30	+37.60
Colorado Springs (CG)	145.60	185.10	+39.50
Albany (CG)	162.60	186.10	+23.50
New York (RFG)	174.80	200.10	+25.30

GASOLINE RACK PRICES

(Cents per gallon)

	5/1/03	4/29/04	Change
Portland	97.22	152.05	+54.83
Reno	95.95	148.25	+52.30
Las Vegas	98.83	153.03	+54.20
California Average	100.73	151.27	+50.54

CHART B

RETAIL PRICE RISE COMPARISON OF CG & RFG

(Cents per gallon)

	7/12/03	7/12/04	Change
Chicago (RFG)	162.00	199.20	+37.20
Champaign (CG)	149.30	187.30	+38.00
St. Louis (RFG)	148.40	185.90	+37.50
Milwaukee (RFG)	156.10	195.00	+38.90
Madison (CG)	154.40	192.50	+38.10
Allentown (CG)	143.60	183.70	+40.10
Philadelphia (RFG)	151.50	196.30	+44.80
Atlanta (RFG)	136.60	178.60	+42.00
Macon (CG)	134.40	172.90	+38.50
Denver/Boulder (CG-low RVP)	143.30	184.50	+41.20
Colorado Springs (CG)	141.40	185.10	+43.70
Albany (CG)	149.20	196.40	+47.20
New York (RFG)	165.70	221.70	+56.00

GASOLINE RACK PRICES

(Cents per gallon)

	7/10/03	7/8/04	Change
Portland	99.39	131.24	+31.85
Reno	104.35	145.49	+41.14
Las Vegas	100.65	144.73	+44.08
California Average	108.46	153.55	+45.09

Mr. HALL. Thank you, Mr. Early.

I recognize Mr. Red Cavaney, President, American Petroleum Institute.

STATEMENT OF RED CAVANEY

Mr. CAVANEY. Thank you, Mr. Chairman, for this opportunity to present the views of API's member companies on U.S. refining capacity and boutique fuels.

Recent gasoline prices, while primarily caused by increased crude oil prices, have underscored the fact that U.S. demand for petroleum products has been growing faster than, and now exceeds, domestic refining capacity. While refiners have increased the efficiency, utilization, and capacity of existing refineries, these efforts have not enabled the refining industry to keep up with growing demand.

Refiners have been operating at an average utilization rate of almost 96 percent over the past few months. To put this in perspective, the average annual utilization rate for all other manufacturing industries is 82 percent. At times during the summer drive season, refiners operate at rates close to 98 percent. With virtually no excess capacity available, such high rates cannot be sustained for long periods of time.

There are a number of reasons why no new refineries or major expansion projects have been undertaken in recent years. Economic factors have discouraged the investment needed to expand capacity. The average annual rate of return on capital investment for petroleum refining and marketing was 5.5 percent over the decade ending in 2002. This is significantly below the 12.7 percent average annual return for the Standard & Poors Industrial. Similar results were also experienced in the decade immediately preceding the one I have just cited.

Just to comply with environmental requirements, refiners must make massive investments while coping with a lengthy permit review process, regulatory uncertainty, stringent max deadlines, and continued NIMBY, the "Not In My Back Yard," public attitude.

The refining situation needs to be addressed now. Congress can take an important step by passing the comprehensive Energy Bill, H.R. 6, which would encourage new energy supply and lead to greater production and distribution flexibility.

Congress should also take some additional steps outlined in my written statement. These include aligning with other industries the depreciation life for refinery assets to 5 years, codifying the President's Executive Order on assessing the energy impact of new regulations, taking steps to speed up the permit review process, codifying EPA's New Source Review reform rule, and minimizing the use of enforcement discretion in fuels regulation.

Turning now to boutique fuels, while the patchwork of these localized fuels is not principally responsible for the recent higher gasoline prices, their proliferation in recent years has presented significant challenges to U.S. refiners and resulted in an inflexible fuel system. A classic example of the disadvantages of boutique fuels is the New York-New Jersey where gasoline intended for use in Bayonne, New Jersey cannot be used to address any supply shortage on the other side of the river in New York City.

Importantly, we urge policymakers to take particular care in addressing boutique fuels, as there are many factors that affect this complex issue, and the law of unintended consequences can prove unforgiving.

API and its member companies believe that the best way to address boutique fuel is to pass the comprehensive national energy legislation, H.R. 6. The Energy Bill would repeal the oxygen content requirement for reformulated gasoline in the Clean Air Act, which is a major driver of boutique fuel. It would also require a national phase-down of MTBE, and have EPA consult with DOE on the supply and distribution impacts of new State requests for specialized fuel.

Finally, H.R. 6 requires EPA and DOE to conduct a comprehensive study of the impacts of boutique fuels, and make recommendations to Congress for addressing them within 18 months of bill enactment.

Given these significant changes and the benefits of the study recommendations, we urge Members of Congress to resist imposition of any additional fuel specification changes outside the context of the national energy legislation.

API, NPRA, fuels marketers, and numerous agriculture and ethanol interests support the fuels provisions in H.R. 6. They offer carefully considered solutions to the fuels problems that have challenged both fuel providers and burdened energy consumers.

Thank you for this opportunity to appear before this panel.

[The prepared statement of Red Cavaney follows:]

PREPARED STATEMENT OF RED CAVANEY, PRESIDENT AND CEO, AMERICAN PETROLEUM INSTITUTE

I am Red Cavaney, president and CEO of the American Petroleum Institute. API welcomes this opportunity to present the views of its member companies on U.S. refining capacity and boutique fuels. API is a national trade association representing more than 400 companies engaged in all sectors of the U.S. oil and natural gas industry.

We are particularly gratified that this subcommittee is taking an interest in refining capacity. To summarize my message today: recent gasoline price increases, while primarily caused by increased crude oil prices, have underscored the fact that U.S. demand for petroleum products has been growing faster than—and now exceeds—domestic refining capacity. While refiners have increased the efficiency, utilization and capacity of existing refineries, these efforts have not enabled the refining industry to keep up with growing demand.

Government policies are needed to create a climate conducive to investments to expand refining capacity. The refining situation needs to be addressed now. Congress can take an important step by passing the comprehensive energy bill, H.R. 6., which would encourage new energy supply and streamline regulations, leading to greater production and distribution flexibility.

The Subcommittee is also considering boutique fuels, and I will address that subject following my discussion of refining capacity.

Challenges for U.S. refiners

While U.S. refiners are producing record amounts of gasoline, strong demand and a reduction in gasoline imports, due—at least in part—to new low-sulfur gasoline requirements, have tightened supply, putting upward pressure on prices. Press reports indicate that Venezuela may be unable to meet its target level for RBOB exports to the U.S., which could further tighten domestic supplies. (RBOB is the petroleum blendstock that is blended with ethanol to make reformulated gasoline.)

Even with refineries running flat out, strong demand has kept inventories below average. Refiners have been operating at an average utilization rate of almost 96 percent over the past few months. To put this in perspective, the average utilization rate for other manufacturers is 82 percent. At times during the summer, refiners operate at rates close to 98 percent. However, with virtually no excess capacity available, such high rates cannot be sustained for long periods, especially given the inevitable need for shutdowns to perform crucial maintenance or to comply with new regulatory requirements.

Regulations affecting the petroleum industry have made it harder for refiners to expand capacity and for distributors to move supplies around, especially when local-

ized refinery and distribution problems occur. Both have contributed to tighter markets and, thus, higher gasoline prices. Four years ago, the National Petroleum Council (NPC), an industry advisory group to the U.S. Department of Energy, noted in a landmark report on the refining industry that the industry would be "significantly challenged to meet the increasing domestic light petroleum product demand with the substantial changes in fuel quality specifications recently promulgated and currently being considered." Some of these changes are now being implemented, including gasoline sulfur reductions and the removal of MTBE from significant parts of the gasoline pool.

In its report, the NPC noted the limited return on investment in the industry and the capital requirements of complying with environmental regulations and urged policymakers to pay special attention to the timing and sequencing of any changes in product specifications. Failing such action, the report cautioned that adverse fuel supply ramifications could result. Therefore, had the NPC recommendations been acted upon when first put forth in 2000, today's shortfall in refining capacity may well have been minimized.

Since the NPC issued its report, refiners have faced many new challenges in meeting gasoline demand. On January 1, 2004, a new federal regulation required the amount of sulfur in gasoline to be reduced from more than 300 parts per million (ppm) to a corporate average of 120 ppm—and then to 30 ppm in 2006—giving refiners an additional challenge in both the manufacture and distribution of fuel nationwide. Equally significant, California, New York and Connecticut bans on the use of MTBE also went into effect January 1. This is a major change affecting one-sixth of the nation's gasoline market.

Where MTBE was used as the required oxygenate in reformulated gasoline (RFG), it accounted for as much as 11 percent of RFG supply at its peak, and the substitution of ethanol for MTBE does not replace all of the volume lost by removing MTBE. Ethanol's properties generally cause it to replace only about 50 percent of the volume lost when MTBE is removed. The missing volume must be supplied by additional gasoline or gasoline blendstocks. The resulting volume loss of moving from MTBE-blended gasoline to ethanol-blended gasoline is primarily due to changes that must be made to gasoline blendstocks (RBOB) to accommodate increased volatility, or RVP, with the use of ethanol. Light-end components of gasoline blendstocks must be removed, accounting for 5-6 percent volume loss. In addition, ethanol may only be blended to as much as 10 percent by volume in gasoline, while MTBE is typically blended at 11 percent by volume in RFG.

Refining capacity has increased but more needs to be done

No new major refineries have been built in the U.S. since 1976. However, upgrading existing facilities has often allowed refiners to expand capacity. Thus, refining capacity has increased at about a 1.5 percent annual rate over the last decade to about 16.7 million barrels per day, even as the number of refineries has decreased to fewer than 150. Similarly, hydrocracker and coker capacity (which allow refiners to produce more light products from an increasingly heavier, more sour, crude slate) has increased by 30 percent and 60 percent, respectively, in the last decade. But progress in increasing refining capacity stalled, as new fuels regulations began to have an impact and EPA's reinterpretation of New Source Review and other regulations, begun in the 1990s, created increased uncertainty and jeopardized past investments for some companies.

This year, short-term changes in crude slates have been made with refiners purchasing sweeter crudes, resulting in higher gasoline yields. However, such strategies are unlikely to be sustained in the face of the long-term production trend towards more sour crudes.

Imports meet 10 percent of U.S. gasoline supply

The U.S. currently must import nearly 10 percent of its gasoline supply to meet demand. This percentage will likely increase as demand for petroleum products outpaces domestic refinery production over the next decade, as projected by the Energy Information Administration. Reliance on gasoline imports has provided refiners with needed flexibility in meeting consumer demand and minimizing tight supplies.

Historically, there has been spare refining capacity worldwide, which has allowed the U.S. to rely on product imports since World War II. However, many believe that excess worldwide refining capacity will have largely been consumed by as early as year-end as a result of growing foreign economies. Perhaps more importantly, the historical volatility in California prices shows that a combination of very high refinery utilization rates and extended transportation routes (imports) leads to volatile supply situations when the inevitable operational interruptions occur.

Barriers to expanded refining capacity

We don't know what prices will do in the future. We do know, however, that we will continue working hard to increase supplies of crude oil and gasoline to meet the nation's energy needs. Companies value their reputations as reliable providers of petroleum products. However, despite increasing capacity at the remaining refineries over the last 10 years, today, our nation has fewer than half the refineries and 90 percent of the capacity of the early 1980s. As for building new refineries, investors will need to believe the return on investment will be adequate into the future and that refiners will be able to obtain the necessary permits. For years, getting permission to build a new refinery or expand existing refineries in the United States has been an extremely difficult, inefficient and inordinately time-consuming process.

While there is increased recognition that refining capacity expansion can help meet the growing consumer demand for petroleum products, there are a number of constraints to expansion:

Economics. Economic factors have discouraged the investments needed to expand capacity. Fuels specifications have become so stringent in the U.S. and Europe that refineries must undertake expensive configuration upgrades to make the products that are required in those markets. Making large capital investments at refineries runs into hundreds of millions of dollars in the case of existing refineries—and from two to three billion dollars for a new refinery. The average annual return on capital investment for petroleum refining and marketing was about 5.5 percent over the decade ending in 2002, which is significantly below the 12.7 percent average return for the S&P Industrials. Such unattractive returns have had a chilling effect on investment in refining infrastructure.

Environmental expenditures. Refiners must make massive environmental expenditures to comply with stringent, complex and often unclear clean air and clean water requirements. These expenditures, particularly those aimed at reducing stationary source emissions, while important, generally yield refiners small and sometimes negligible economic returns on investment. These regulatory investments also compete with those funds that might otherwise be committed to discretionary expansion projects. The pacing and timely clarification of regulatory requirements can help maximize opportunities for both emissions reductions and some incremental gains in capacity.

The U.S. oil and natural gas industry as a whole spent $9.1 billion to protect the nation's environment in 2002. From 1993 to 2002, API estimates the industry spent almost $89 billion to protect the environment. This amounts to $308 for every man, woman, and child in the United States. More than half of the $89 billion was spent in the refining sector of the industry. The $9.1 billion in environmental expenditures in 2002 was equal to about 47 percent of the net income of the top 200 oil and natural gas companies, as reported in *Oil & Gas Journal.* Moreover, the industry's investments currently underway in additional clean fuels requirements in this decade will be considerable: $8 billion for gasoline sulfur reductions; another $8 billion for highway diesel sulfur reductions; and more than $1 billion for non-road diesel.

Regulatory requirements. Once a decision has been made to expand an existing refinery or to build a new one, the process for licensing, obtaining construction and operating permits and many other required steps can take up to four years, sometimes longer. The permitting process can be lengthy, with no guarantee that permits will ultimately be issued. Public involvement as part of most permit review requirements is typically not subject to time limits or deadlines and can result in an open-ended process, increasing uncertainty and ultimate project cost.

Regulatory uncertainty. Refiners who must make major, long-term investments to build new refineries or expand existing ones must have confidence that the rules will not be changed in mid-course. Uncertainty about laws and regulations creates a major disincentive to investment. Moreover, the extremely complex and often unclear New Source Review regulations (only recently and partially reformed by EPA) discouraged refineries from undertaking expansion projects and improving process efficiency by contributing to overall uncertainty about regulatory requirements. In addition, litigation challenging EPA's recent NSR reforms has stymied efforts to integrate those reforms into state air programs. Not surprisingly, little capacity expansion has occurred in the past several years or is planned for the immediate future.

Public attitudes. Another obstacle to new refineries is NIMBY ("not-in-my-backyard") sentiment. Given the likely public opposition to siting a new refinery in many communities in the U.S., most companies are unlikely to undertake the significant investments needed to even begin the process when the likelihood of success is so uncertain.

National Ambient Air Quality impacts. Building new refineries or expanding existing ones has been difficult under the constraints of the 1-hour ozone National Ambi-

ent Air Quality Standard (NAAQS) and the New Source Review permit program requirements. The new 8-hour ozone NAAQS is much more stringent and creates many more non-attainment areas that are subject to more stringent requirements than attainment areas, including barriers to permitting of new stationary sources. The expected implementation of the $PM_{2.5}$ air quality standards in 2005 will add still more non-attainment areas in which it will be difficult or impossible to obtain construction and operating permits for expansions or new refineries. Moreover, a number of refining and petrochemical manufacturing areas of the country face deadlines under the new 8-hour ozone NAAQS implementation rule that do not provide adequate time for some manufacturers to install the very stringent emission control technologies likely to be required to attain the standard. Yet, manufacturers in other areas may be forced to reduce their emissions simply because the deadlines do not recognize the projected air quality benefits of newly required national fuel and vehicle changes and interstate emissions transport controls.

Increased refining capacity means more jobs

New refining capacity would not only help meet U.S. gasoline demand, it would also produce jobs. As of April of this year, total refinery employment was 70,100, or an average of 480 jobs per refinery. However, based on U.S. Department of Commerce data, every $1 billion of increased production of refined products yields an estimated 400 new jobs at a refinery, plus 4,700 "indirect" jobs involved in producing and supplying materials used in the refinery. An additional 5,500 "induced" jobs are produced through the general impact on the economy. These estimates likely understate the jobs impact because they do not reflect the effects of investment on economic growth. In addition to producing jobs, increased refining capacity would enable refiners to more successfully meet consumer demand and reduce supply volatility and price volatility, thereby strengthening the overall U.S. economy and contributing to further economic growth.

Recommended actions

API and its members believe that the following actions would help create a more favorable and predictable investment climate that could encourage building additional refining capacity:

- *National Petroleum Council recommendations should be acted upon.* Congress should enact legislation directing the Secretary of Energy to implement the findings and recommendations in the June 2000 National Petroleum Council (NPC) report, *U.S. Petroleum Refining—Assuring the Adequacy and Affordability of Cleaner Fuels.* Had these recommendations been acted upon when first proposed in 2000, today's shortfall in refining capacity—a situation that, in the absence of action, was predicted by the NPC report—might have been minimized. Secretary Abraham recently asked for the report to be updated and expanded, and the industry is working through the NPC to develop a new set of recommendations.
- *Refinery assets should be five-year property.* When the industry testified before the House Ways and Means Subcommittee on Select Revenue Measures in June 2001, it noted that one way of helping to create a climate more conducive to new refining capacity investments was to eliminate the outdated tax treatment of those investments. We reiterate that view today. Most manufacturing assets are depreciated over five or seven years. Chemical manufacturing assets, which are very similar in nature to petroleum refinery assets, are, in fact, depreciated over five years. Despite substantial changes in the refining business and considerable investment made during the last decade and a half, refinery assets are still subject to a 10-year depreciation schedule. The longer recovery period for refinery capital assets results in a depreciation deduction present value that is 17 to 25 percent less than that for other manufacturing assets, thereby reducing the incentive to invest in refinery capacity expansion projects. Shortening the depreciation life for refinery assets to five years will reduce the cost of capital, make those investments more competitive with alternative capital investments, and remove the current bias in the tax code against needed refinery capacity expansion.
- *Executive order on energy impact should be codified.* Executive Order 13211, signed by the President in 2001, requires that agencies prepare a "Statement of Energy Effects," including impacts on energy supply, distribution and use, when undertaking certain regulatory actions. The order has rarely, if ever, been fully implemented. This has been most apparent as EPA has promulgated numerous major fuel and facility regulations affecting the U.S. refining industry, with only superficial analysis for Executive Order 13211. The industry will be faced by over a dozen new environmental programs by 2010—programs that

should have received a more robust review under Executive Order 13211. In order for policymakers and the public to better understand potential energy supply impacts of new environmental policies and regulations, Executive Order 13211 should be codified in legislation passed by Congress.

- "Reasonable Permit Review Act" should be passed. One of the major disincentives to expanding refining capacity is the numerous permitting requirements and the time it takes to get permits reviewed and issued. Congress should enact a "Reasonable Permit Review Act" designed to coordinate and eliminate overlap among the numerous permitting processes. The legislation could direct federal agencies involved in permit review to enter into a memorandum of understanding that would clearly define the steps to be taken when federal permit review and approvals are required.
- *Avoid excessive use of enforcement discretion.* EPA and other federal, state and local agencies regulating fuels should minimize creating situations that are likely to result in the use of enforcement discretion for existing regulatory requirements. Although occasionally necessary as a last resort to prevent unintended or untenable consequences, the uncertainty can exacerbate the supply situation. Agencies should adopt policies that clearly outline the processes and requirements suppliers would need to follow during periods of supply disruption, removing the need for, and uncertainty associated with, use of enforcement discretion.
- *Codify EPA New Source Review (NSR) reforms.* Congress should codify into federal law EPA's NSR reform rules that are expected to remove obstacles to greater efficiency, encourage industry to modernize refineries, and simultaneously provide a clear and reasonable requirement for the installation of new pollution controls to reduce emissions. The NSR regulations had become a cumbersome, confusing, ineffective and sometimes counterproductive tool for regulating air emissions under the Clean Air Act. Those regulations have discouraged refineries from expanding capacity and improving efficiency. The reformed rules will provide greater clarity, resulting in more efficient regulation and a reduction in the uncertainty factor.
- *Provide State Environmental Permitting Assistance (SEPA).* Congress should enact legislation directing EPA and other agencies to lend appropriate technical, legal and other assistance to states whose resources are inadequate to meet permit review demands. This concept could be implemented by earmarking federal resources for state refinery permit reviews. In order to take advantage of this federal assistance, states would be required to establish a refining infrastructure coordination office to facilitate federal-state cooperation in permit reviews.

No single government action will ensure that additional refining capacity will be built, but positive government policies can help bring about a climate more conducive to increased investment. Decisions to add new capacity are primarily business decisions. Investments will be more likely in a climate of regulatory certainty, with well-defined permitting requirements and timelines and assurance that the government won't keep changing the rules. Industry is not suggesting a rollback of environmental safeguards; what is needed is more efficient, less time-consuming regulatory procedures that safeguard the environment without resulting in needless and excessive delays in obtaining permits and meeting other requirements.

Boutique Fuels

While the patchwork of localized "boutique fuels" is not principally responsible for the recent higher gasoline prices, the proliferation of these fuels in recent years has presented significant challenges to U.S. refiners and resulted in an inflexible fuels system. A classic example of the disadvantages of boutique fuels is in the New York/New Jersey area where gasoline intended for use in Bayonne, New Jersey, cannot be used on the other side of the river in New York City to address any supply shortage. Refiners and suppliers have made the refinery and distribution system investments to handle both of these gasolines with minimal problems to date. However, if a serious infrastructure problem occurs in the refineries, the pipelines, or the terminals that supply these areas with gasoline, the boutique fuels involved could lead to serious supply disruptions. We urge policymakers to take particular care in addressing boutique fuels, as there are many factors that affect this complex issue.

Priority should be assigned to the repeal of the federal RFG oxygen requirement—and, of equal importance, to avoiding simplistic, counter-productive solutions that fail to recognize how the U.S. fuels system operates. Consideration should be given to both the refining distribution system and the availability of similar fuels in each area. For example, some advocate a national 7.8 pound RVP requirement, but ignore the fact that, while 7.8 pound RVP fuel is the standard fuel in southern nonattainment areas, its use in other areas of the country is limited. Thus, a bill that would

allow 7.8 RVP fuel in any state that desired it would lead to a boutique fuel if, for example, this fuel was adopted in New Hampshire.

API and its members believe that the best way to address boutique fuels is to pass the comprehensive national energy legislation, H.R. 6. The energy bill would repeal the oxygen content requirement for reformulated gasoline in the Clean Air Act, a major driver of boutique fuels, and require a national phasedown of MTBE. It also requires that EPA consult with DOE on the supply and distribution impacts of new state requests for specialized fuels. Finally, H.R. 6 requires EPA and DOE to conduct a comprehensive study of the impacts of boutique fuels and make recommendations to Congress for addressing them, within 18 months of enactment. Given these significant changes and the benefit of the study recommendations, we urge members of Congress to resist imposition of any additional fuel specification changes outside the context of the national energy legislation.

API, the National Petrochemical & Refiners Association, fuels marketers, and numerous farm and ethanol interests support the fuels provisions of H.R. 6. They offer carefully considered solutions to the fuels problems that have challenged fuel providers and burdened energy consumers.

Mr. HALL. Thank you very much, sir. Thanks for your support of H.R. 6.

Mr. Schaeffer, we recognize you at this time, Director of Environmental Integrity Project. Let me say this, before you begin, don't be dismayed by the lack of attendance. These men and women have other committees they have to attend, and actually you are called here to give us your testimony, it is taken down, each one gets copies of it. As a matter of fact, whether there is 1 or 5 or 30 of the members here, it goes to everyone, and it is all considered when we get together to write the law. We ask you, as men and women who know more about your own business than we know, and we base these laws on your testimony here. So, it is not wasted on just a couple of guys from Texas up here that have unusual interest in energy. And you have the presence of several committee people here that really do most of the work and a lot of the thinking for us. Proceed.

STATEMENT OF ERIC SCHAEFFER

Mr. SCHAEFFER. Thank you, sir. Thank you, Mr. Chairman. Speaking of testimony, I made some minor changes last night that are incorporated in the copy you have.

Mr. HALL. The entire statement of all of you will be placed in the record. Your entire statement will go to the record without objection.

Mr. SCHAEFFER. Thank you, sir. I would like to question the basic premise that environmental permitting acts as a significant drag on expansion of refinery capacity, and would like to offer maybe a little more optimistic perspective and give the industry some credit.

U.S. refining capacity has expanded at a pretty brisk pace in the 1990's. This happened after the 1990 Clean Air Act when lots of new requirements came into play. We are at record levels of production in motor gasoline. We have had substantial increases there. According to the Energy Information Administration, we have added the equivalent of one medium-size refinery a year through expansion of existing plants. I think the industry's decision to build out its capacity at existing sites is more likely a business decision than one driven primarily by permitting.

I would point out that the average refinery has doubled in size since the 1980's, that is why we have more capacity. I am strug-

gling to understand how New Source Review, which has become kind of an urban legend now for the industry, has acted to limit capacity growth if refineries are twice as big as they used to be. We have been living with these requirements for a long time.

I would like to express some concern while I have the chance, or at least raise some questions about the Refinery Revitalization Act. If there are no objections, I would like to submit statements of opposition from all the environmental groups as well as the National Conference of State Legislatures and associations representing State permitting officials.

Mr. HALL. You have something you want to submit for the record?

Mr. SCHAEFFER. I do, all the written statements.

Mr. HALL. Without objection.

Mr. SCHAEFFER. Thank you, Mr. Chairman. I would like to make four points very briefly. As I understand the legislation, if you are in an economically distressed area, which seems somewhat vaguely defined, a refinery at that location that wanted to restart or build, would get a fast-track permitting process from its friends at the Department of Energy.

If the idea is to increase total capacity in the country, I question whether an approach that essentially creates geographic disparity, in effect, invites refiners to move from an area where permitting is stringent to an area where it is faster and cheaper is going to do much to increase overall supply, but whether, instead, it will exaggerate regional shortages that do seem to be a problem, at least when it comes to production of clean fuels, in certain markets. In other words, is it a good idea to encourage refiners, based on differential permitting, to move away from Pennsylvania or California to other areas where there may already be a surplus of capacity, just because permitting is cheaper and easier and they can deal with the Department of Energy instead of EPA?

Second point I want to make is, no matter what the Congress does, it is very, very difficult to force a refinery on a community that just doesn't want it. And as I read the provisions of this bill, it would allow the Department of Energy to do that, and DOE would be empowered to override the objections of State permitting authorities who traditionally get to decide whether a permit is issued or denied. That seems to me a recipe for more conflict and more litigation.

If I could point to one example, the Synco Refinery's proposed restart in California. The permit in that case was granted. It was granted by EPA and by the State. The community did not want that refinery. They didn't trust the owner. They didn't think it was meeting its environmental obligations. They went to Federal Court. They won. The refinery didn't go forward. The problem didn't lie in the permit, it lay in the opposition of the community and in their perception that this was not a refinery that was going to comply with the law.

A third point I want to make is, managing refineries is an awesome and very difficult responsibility. I have a lot of respect for the men and women of the industry who do that well, it is a very, very hard job. I would worry that fast-track permitting would encourage the entry into the market of companies that are under-financed

and, frankly, incompetent and unprepared to take on those responsibilities. And I would offer the case study of the Orion Refinery. I think it offers a cautionary tale.

Orion came to us wanting to restart a 185,000 barrel a day plant in Louisiana in the year 2002, came to EPA when I was still working there. We expressed some concern about the capacity of that company to undertake that reopening and operate the refinery safely. Nonetheless, they granted the permit and EPA didn't object.

What happened? As soon as they opened, they were plagued by a series of accidents. This has to have been one of the most accident-prone refineries I have ever seen. They flared night and day. They dumped thousands of tons of pollutants on neighboring residents. They were sued by neighboring residents. They were sued by the State. This all ended with a big fire at the coking plant at the refinery, which ultimately shut the plant down. They are now in bankruptcy. We don't have any supply, but we have a lingering memory in that neighborhood of citizens having been showered with coke dust.

So, when we want to talk about the NIMBY issue and why communities are so anxious about having refineries come to their neighborhood, I would just suggest that having your coker explode and deposit chunks of hot metal in a schoolyard—this happened at another plant in Louisiana—is not the way to win the hearts and minds of your neighbors, and kind of warm them to the idea of refinery expansion. That problem needs to be dealt with, which leads to my last point.

The industry, I think it is fair to say, has a checkered history of complying with the Clean Air Act. Some companies have done a good job——

Mr. HALL. Would you try to wind down, Mr. Schaeffer.

Mr. SCHAEFFER. Thank you. We get so few opportunities to raise these issues.

Mr. HALL. Well, your entire statement is going to be there, but go ahead, we will let you finish.

Mr. SCHAEFFER. I can be very brief. Attached to my statement, you will see a list of companies that EPA has identified with notices of violations, some going back to 1998. These are refineries with violations that have been hanging for a long time. The Administration, EPA, the Department of Justice, they are not moving on any of these cases.

I guess I would close by asking, what good is an environmental permit, no matter who issues it and no matter how it is granted, if its terms and conditions are never going to be enforced? Thank you, Mr. Chairman.

[The prepared statement of Eric Schaeffer follows:]

PREPARED STATEMENT OF ERIC SCHAEFFER, DIRECTOR, ENVIRONMENTAL INTEGRITY PROJECT

Thank you, Mr. Chairman and Members of the Subcommittee, for the opportunity to testify today. My name is Eric Schaeffer, and I am currently director of the Environmental Integrity Project, a nonprofit organization that advocates for effective enforcement of environmental laws. Previously, I served as director of the USEPA's Office of Regulatory Enforcement, where I had a role in negotiating a series of Clean Air Act settlements with refinery companies.

I want to question the notion that environmental laws, rather than market forces, have limited the ability of U.S. oil companies to expand refinery capacity in the

United States. I also want to raise specific concerns about H.R. 4517, the United States Refinery Revitalization Act of 2004, which was recently approved by the House of Representatives without any hearings and with little debate. My testimony will make the following points:

- U.S. refining capacity has expanded recently in response to market signals, and is at an all-time high. While additional capacity may be helpful, there is little evidence that permitting requirements are a significant barrier to new investment.
- Environmental permitting requirements are admittedly challenging. But H.R. 4517 would set up a two-tiered permitting system based on geographic differences in employment statistics that may change rapidly, will make the system more complex, and may do more to shift refining capacity than increase it.
- States are primarily responsible for permitting U.S. refiners, with oversight from EPA and with the opportunity for meaningful comment from the public. H.R. 4517 apparently allows the Department of Energy to grant permits that states want to deny, and will increase local hostility to expansion projects by effectively shutting communities out of decision-making.
- The Department of Energy is not a regulatory agency, and is not qualified to interpret federal environmental laws.
- The fast-track permitting authorized by H.R. 4517 encourages the entry of undercapitalized and poorly managed companies into the marketplace, which may lead to environmental disasters and interruption of gasoline supplies.
- The Bush Administration has deliberately refused to enforce the Clean Air Act and other environmental laws against U.S. refineries. If the government is unwilling to enforce permit limits, then the permitting process is ultimately meaningless, no matter who is in charge.

U.S. REFINING CAPACITY—NOT IN CRISIS

According to the Energy Information Administration, refining capacity has increased steadily over the past decade to levels not seen since the early 1980's. Meanwhile, improvements in downstream processing have raised the output of gasoline to record levels. As the attached data from the Department of Energy (Table A) shows, gasoline output at U.S. refineries grew faster in the nineties than in the preceding two decades. That this faster rate of growth occurred after the Clean Air Act of 1990, which imposed significant new emission control and clean fuels requirements for refiners, suggests that environmental factors are not a significant drag on the expansion of capacity.

The refinery industry has played an active role in writing the rules that govern its operations, which have frequently been relaxed to accommodate its concerns. Clean fuels requirements have been extended for refineries pleading economic hardship, and New Source Review requirements that apply to existing facilities have been substantially weakened. Refineries expanded capacity at existing plants at a healthy pace in the late nineties, contradicting the notion that NSR limited growth. But even if you believe that the old NSR rules did constrain capacity (and I do not), the Bush Administration has rewritten them to the refinery industry's liking.

We hear frequently that refineries are operating at near maximum capacity. But that is historically true, and data from the Energy Information Administration again shows refiners have historically operated close to capacity limits. Environmental requirements undeniably impose costs on refiners, but may also give them a competitive advantage over foreign refiners unable to meet U.S. requirements for clean fuels.

I do not mean to suggest that permitting requirements play no role in decisions to expand or build refineries, but that traditional market forces—such as the high prices motorists now pay at the pump—may provide far more powerful incentives to invest in increased supply.

SHUFFLING THE DECK INSTEAD OF INCREASING SUPPLY

H.R. 4517 would designate "refinery revitalization zones" in areas that have experienced "mass layoffs" or have idle refineries, and which have unemployment rates 20 percent above the national average. The Department of Energy would step in to manage environmental permitting for refineries in these revitalization zones, with permits to be granted within six months. This approach creates a two-tier scheme, reserving traditional permitting for some areas while establishing an industry-friendly "fast-track" for others. Those who favor this approach should answer three questions:

- Would this approach actually increase total refinery capacity, or merely encourage shifting expansion projects from one geographic area to another, based on small differences in local employment rates?
- How would this approach assure that refinery capacity is added where it is needed most to alleviate local shortages in gasoline and clean fuels?
- Refineries have expanded capacity by more than ten percent over the past decade. Has this added capacity increased employment, or have payrolls in fact been substantially cut to improve refinery profit margins?

H.R. 4517 LIMITS POWER OF STATES AND LOCAL COMMUNITIES

Since their inception, federal environmental laws have recognized that states have the primary authority for issuing permits, subject to minimum national standards and EPA oversight. Equally important, the public has a right to review and comment on major permits, and to have their objections fairly considered by permitting authorities. While vaguely worded, H.R. 4517 seems to authorize the Department of Energy to permit a new refinery over the objection of the state and the local community. It's little wonder that the National Conference of State Legislatures, the Environmental Council of States (representing state environmental commissioners) as well as STAPA/ALAPCO (representing state air permitting programs) are strongly opposed to H.R. 4517. National and local environmental organizations have unanimously opposed this legislation as well.

Is the Department of Energy going to start running the public hearings that the Clean Air Act requires for any major expansion projects? Regardless, citizens who challenge the Department of Energy's decisions in court would have to fly to Washington DC and appear before the DC Circuit Court of Appeals. Riding roughshod over the right of local communities to object to the siting of facilities that may affect their health and property values seems sure to provoke an angry backlash that may work against the goals of this legislation in the long run.

THE DEPARTMENT OF ENERGY IS NOT QUALIFIED TO RUN ENVIRONMENTAL PERMITTING PROGRAMS

As the attached June 14 letter from the Environmental Council of States points out, the Department of Energy is "an agency with expertise on energy production, not environmental regulations." There is no evidence to suggest that DoE is up to handling the new powers it would receive under H.R. 4517. In fact, the Department already has its hands full managing multibillion dollar environmental cleanups at Hanford, Rocky Flats, Portsmouth and other facilities it owns or manages. I would respectfully suggest that Congress not grant the Department of Energy new power to interpret laws it is still struggling to comply with.

FAST-TRACK PERMITTING MAY SET POORLY MANAGED COMPANIES UP FOR FAILURE

Managing a refinery safely and in compliance with environmental laws is a challenging endeavor. Rushing permits for companies ill-prepared to meet these challenges is a recipe for environmental disaster. The case of the now-closed Orion refinery offers a cautionary tale. Orion's investors approached EPA in 2000 to ask for help expediting a permit for a refinery with a troubled past that it proposed to reopen in Norco, Louisiana. At the time, EPA staff expressed concern over the company's ability to safely manage the plant, but the permit was nonetheless granted. Our worst fears were realized, as the star-crossed Orion refinery stumbled through one mishap after another, and a series of malfunctions shed thousands of tons of illegal pollutants on nearby neighborhoods. Ultimately, the refinery was forced into bankruptcy after a fire at its coker shut down operations. Gasoline supplies were temporarily curtailed (the refinery has since been purchased by Valero) and residents were left with the bitter experience of living with a shoddy operation.

Some refineries are simply accident prone, and release emissions far in excess of permitted levels because they are apparently unable to maintain their equipment in working order. One of the most notorious examples, the Atofina refinery in Port Arthur Texas, annually releases several thousand tons of sulfur dioxide as a result of malfunctions, or about ten times the amount that it reports annually from routine operations. These types of incidents—and the government's failure to put a stop to them—do not inspire confidence in the company's ability to manage a significant expansion of capacity.

REFINERY ENFORCEMENT HAS BEEN DERAILED

While the industry urges fast-track permitting, the Bush Administration has effectively derailed enforcement against refineries for violating laws already on the

books. Table B lists outstanding notices of violation against U.S. refineries, some dating back six years, for failing to comply with the Clean Air Act. The U.S. Department of Justice has not filed complaints against any of these facilities, creating the unfortunate impression that these companies enjoy some kind of political protection. Worse still, the failure to enforce the law has undercut those responsible refiners who are spending hundreds of millions of dollars to clean up their plants under the terms of settlements reached with the federal government and state partners.

The refinery lobby has complained for years that a "not-in-my-backyard" syndrome has made it impossible for companies to build new refineries in the United States. There may be some truth to what the industry says, but that claim is difficult to evaluate given the failure of refiners to submit any serious applications for new refineries over the past twenty years. But in the final analysis, the industry needs to recognize that the failure of some of its members to respect environmental law has contributed to an atmosphere of cynicism and distrust. Recently, some companies—BP, Marathon-Ashland and Koch, for example—have shown signs on at least some issues of breaking free of the old paradigm, by taking responsible actions that could help to restore trust between refineries and their neighbors. Turning environmental permitting over to the Department of Energy, and allowing it to license refineries that neither states nor communities want, would only threaten the fragile progress we have made so far.

TABLE B

Petroleum Refineries with Outstanding NSR Notices of Violation

Company	Facility	Date NOV Issued
ExxonMobile	Paulsboro, NJ	1/29/2001
Phillips Puerto Rico Core	Guyama, PR	1/22/1999
Sunoco, Inc.	Marcus Hook, PA	12/20/2001
United Refining	Warren, PA	6/24/98, 10/19/00
Citgo Petroleum Corp.	Lemont, IL	3/17/98, 6/28/99, 3/22/02
Sun Refining & Marketing	Oregon, OH	12/19/2001
Mobile Oil	Joliet, IL	8/30/2000
ExxonMobile Oil	Joliet, IL	8/20/2000
Citgo Petroleum Corp.	Lake Charles, LA and Corpus Christi, LA	1/19/2001
ExxonMobile Oil	Beaumont, TX	12/20/2001
ExxonMobile Oil	Baytown, TX and Beaumont, TX	8/20/2002
Lyondell-Citgo	Houston, TX	1/18/2001
Phillips Petroleum	Borger, OK	2/27/1998
Phillips Petroleum	Woods Cross, TX	2/25/1999

Mr. HALL. Thank you, Mr. Schaeffer.

I am pleased to recognize Bill Douglass, of my district, a leader in Northeast Texas and head of the Douglass Distributing Company, many convenience stores across my area in Northeast Texas, 150 retail locations through Dallas and Fort Worth. Mr. Douglass, we are happy to have you. Proceed.

STATEMENT OF BILL DOUGLASS

Mr. DOUGLASS. Thank you, Mr. Chairman and members of the subcommittee, and thank you for inviting me to testify today. As you said, we are headquartered in Sherman, Texas, in the Fourth Congressional District, and we operate convenience stores and supply gasoline and diesel to 150 locations throughout the Greater Dallas-Fort Worth market. I appear before the subcommittee today representing the National Association of Convenience Stores, which we call NACS, and the Society of Independent Gasoline Marketers of America, which we call SIGMA. You may question why am I testifying today, and what message do independent motor fuel marketers have to offer with respect to domestic refining capacity.

Collectively, NACS and SIGMA members sell approximately 80 percent of all the gasoline and diesel sold in the United States

today. And I feel strongly, as do my colleagues within NACS and SIGMA, that this Nation needs additional refining capacity. Independent marketers are, in essence, proxies for consumers, your constituents and our customers. We rely on plentiful sources of gasoline and diesel fuel supplies from diverse sources. When supplies are low or sources of supply are reduced, competition is reduced, and the check that the independent marketers represent on higher motor fuel prices becomes less relevant.

Our message to this subcommittee is simple—our Nation's domestic refining industry is shrinking at a time when consumer demand continues to rise. Unless we collectively change course, domestic refining capacity will be unable to keep up with the pace of the demand. Gasoline and diesel fuel price spikes will become the norm rather than the exception, and our Nation will become more reliant on imports of gasoline and diesel fuel. This subcommittee and this Congress must investigate ways to encourage rather than discourage the expansion of our Nation's domestic capacity to make gasoline and diesel fuel.

NACS and SIGMA may differ with our friends in the refining industry on this issue. Their position is understandable. If you were to ask me if I wanted additional retailers—that is, new competitors—opening gasoline facilities in the Dallas-Fort Worth market, I would respond emphatically, "no." Likewise, it would be understandable if our Nation's domestic refiners were to oppose the addition of new capacity, however, it is your role as elected representatives of our Nation's citizens to determine what public policies are in the best interest of the Nation as a whole, and not a small segment of it.

NACS and SIGMA recommend that this subcommittee consider three different, yet related, areas for public policy for changing the path on which we currently travel. First, implement regulatory reform. NACS and SIGMA urge Congress and the EPA to move forward with New Source Review reform that will continue to protect the environment while enabling facilities to expand capacity and satisfy consumer demand. In addition, Congress should streamline the process for obtaining Federal and State permits without sacrificing environmental protection, and to encourage the expansion again of refining capacity. Chairman Barton's legislation, H.R. 4517, takes an important step in this direction.

Second, incentivize expansion of refining capacity. NACS and SIGMA believe Congress should adopt changes to the Federal Tax Code to incentivize domestic refiners to expand capacity. Such changes might include faster depreciation periods, the ability to expense environmental upgrades when capacity is also expanded, or an investment tax credit aimed at encouraging the construction of new clean-fuels refineries.

The third, address boutique fuels. Additional refining capacity will go a long way to restoring the balance between supply and demand, but it alone is not sufficient to restore fungibility to the system. The balkinization of the Nation into islands of boutique fuels leads to regional supply shortages and price spikes by reducing the market's ability to adjust to supply conditions. NACS and SIGMA suggest that Congress can address these problems by, first, repealing the oxygen requirement of the Clean Air Act as provided for in

H.R. 6; next, placing a moratorium on new fuel formulations as provided for in H.R. 4545, and identifying ways to reduce the number of fuels in the market without sacrificing supply.

NACS and SIGMA believe that the above provisions would result in more domestically produced gasoline and diesel fuel, additional capacity to respond to supply emergencies, greater flexibility in the distribution system, and a more stable motor fuels marketplace, all while continuing to improve air quality.

The availability of gasoline and diesel fuel to all markets is essential. By expanding capacity and rationalizing the fuel specifications between markets, Congress can improve the operations of the market for the benefit of the consumer.

Thank you for this opportunity to speak with you, and I look forward to answering any questions you may have.

[The prepared statement of Bill Douglass follows:]

PREPARED STATEMENT OF BILL DOUGLASS, CHIEF EXECUTIVE OFFICER, DOUGLASS DISTRIBUTING COMPANY, REPRESENTING THE NATIONAL ASSOCIATION OF CONVENIENCE STORES AND THE SOCIETY OF INDEPENDENT GASOLINE MARKETERS OF AMERICA

I. INTRODUCTION

Good morning, Mr. Chairman and members of the Subcommittee. My name is Bill Douglass. I am Chief Executive Officer of Douglass Distributing Company, headquartered in Sherman, Texas. My company operates 13 convenience stores and supplies gasoline and diesel fuel to 150 retail locations throughout the Dallas-Fort Worth area.

I appear before the Subcommittee today representing the National Association of Convenience Stores ("NACS") and the Society of Independent Gasoline Marketers of America ("SIGMA")

II. The Associations

NACS is an international trade association comprised of more than 1,700 retail member companies operating more than 100,000 stores. The convenience store industry as a whole sold 142.1 billion gallons of motor fuel in 2003 and employs 1.4 million workers across the nation.

SIGMA is an association of more than 250 independent motor fuel marketers operating in all 50 states. Last year, SIGMA members sold more than 48 billion gallons of motor fuel, representing more than 30 percent of all motor fuels sold in the United States in 2003. SIGMA members supply more than 28,000 retail outlets across the nation and employ more than 270,000 workers nationwide.

III. Marketers Urge Policies to Increase Domestic Refining Capacity

Today's hearing is exceptionally important, Mr. Chairman, and I am very pleased you have invited me to testify. I feel strongly, as do my colleagues within NACS and SIGMA, that this nation needs additional domestic refining capacity. This Subcommittee, and this Congress, must investigate ways to encourage, rather than discourage, the expansion of our nation's domestic capacity to make gasoline and diesel fuel.

Collectively, NACS and SIGMA members sell approximately 80 percent of the gasoline and diesel fuel in the United States each year. However, like the vast majority of NACS members, and all SIGMA members, my company does not refine gasoline or diesel fuel. Consequently, you may question why I am testifying before you today and what message independent motor fuel marketers have to offer with respect to domestic refining capacity that is relevant to today's hearing.

Our message to this Subcommittee today is simple. Our nation's domestic gasoline and diesel refining industry is shrinking at a time when consumer demand continues to rise. Unless we collectively change course, domestic refining capacity will be unable to keep pace with demand, gasoline and diesel fuel price spikes such as the one we have experienced this year will become the norm rather than the exception, and our nation will become more reliant on imports of gasoline and diesel fuel to meet increased consumer demand in the coming years.

Independent marketers are, in essence, proxies for consumers—your constituents and our customers. We buy gasoline and diesel fuel directly from integrated and independent refiners and then compete with them directly in the marketplace for retail market share. Independent marketers have long been recognized as the most

cost competitive segment of the nation's motor fuels distribution industry. We rely on plentiful sources of gasoline and diesel fuel supplies from diverse sources in order to occupy this competitive niche in the marketplace. When supplies are low, or sources of supply are reduced, competition is reduced and the check that independent marketers represent on higher motor fuel prices becomes less relevant.

The gasoline and diesel fuel wholesale and retail price volatility experienced by marketers and consumers over the past several years, including the price spike we experienced this Spring and early Summer, is the direct result of an imbalance between increased consumer demand for gasoline and diesel fuel and reduced domestic refining capacity. It is simple fact that consumer demand has grown at a rate faster than domestic refining capacity has been able to expand. The simple laws of economics provide that when demand outpaces supply, prices go up. This year, aided by high crude oil prices, the retail price of gasoline topped $2.00 per gallon on a national average because of an extremely tight supply-demand situation.

Congress has a choice—it can either pursue policies that will encourage the expansion of domestic refining capacity, or it can turn its gaze overseas for our nation's future gasoline and diesel fuel needs. We have listened for years as Congress lamented America's dependence on foreign crude oil. A similar situation is developing with respect to finished crude oil products, including gasoline and diesel fuel.

NACS and SIGMA may differ with our friends in the refining industry on the issue of expanding domestic refining capacity. Their position is understandable. If you were to ask me if I wanted additional retailers opening gasoline facilities in the Dallas-Fort Worth market, I would respond emphatically "NO." I have witnessed first hand what happens when new competitors enter the market and it does not benefit my business interests. Understandably, if one asks our nation's domestic refiners if they want additional refining capacity on the market, the answer should be an emphatic "NO" as well. However, it is your role as the elected representatives of our nation's citizens to determine what public policies are in the best interests of the nation as a whole, not a small segment of it.

The refining industry has outlined the regulatory and financial impediments that are preventing significant capacity expansion or the construction of new refineries. NACS and SIGMA believe Congress should take the initiative to address these stated impediments and open the door to new capacity.

IV. The Statistics on Domestic Refining Capacity

Other witnesses at this hearing will offer detailed information on the current status of the domestic refining industry and I will not repeat this information here. However, it is important to acknowledge several statistics that highlight the problems our nation's refining industry is facing.

Consumer demand for gasoline and diesel fuel continues to grow. The Energy Information Administration ("EIA") projects that consumer demand for motor fuels will increase by almost 30 percent between now and 2025. At the same time, due to limited domestic refining capacity, EIA projects that America will import at least 20 percent of our finished motor fuels by 2025.

This imbalance between domestic refining capacity and demand has been building for decades. According to EIA, the number of refineries in the United States has declined by more than 50 percent in the past 20 years. And, as this Subcommittee is well aware, the last new domestic refinery was built 28 years ago.

In 1981, the combined capacity of the nation's 324 refineries was 18.6 million barrels per day. In 2002, there were only 153 refineries, but capacity had only declined to 16.8 million barrels per day. I must commend the refining industry for its efforts to improve its efficiencies and expand capacity at remaining facilities. Since 1981, the average capacity per refinery has increased from 57,000 barrels per day to 110,000 barrels per day. This is an outstanding accomplishment, but it has not come without costs.

Our nation's refineries are now routinely operating above 95 percent capacity, which is in effect 100 percent capacity with respect to production of gasoline and diesel fuel. We have witnessed in recent years that such a high level of performance carries with it an increased risk of unanticipated interruption due to refinery breakdowns. The pressure on the industry to produce more and more gasoline and diesel fuel from fewer facilities is taking its toll on the industry's equipment. And each time one of these refineries goes off-line, there is not sufficient extra supply in the refining industry to offset this temporary supply shortfall. The result, for marketers and motorists, is constant demand, decreased supplies, and price spikes.

To supplement domestic refining capacity in order to meet consumer demand, the nation in recent years has turned to more imported gasoline and diesel fuel. In 1983, the United States relied on foreign suppliers for 223,000 barrels per day of motor gasoline. Between 2000 and 2003, the nation imported an average of 716,000 barrels per day and thus far in 2004 imports have averaged 868,000 barrels per day.

The EIA projects that, in order to meet demand and build stocks to normal levels, the nation must, at a minimum import approximately one million barrels per day through the end of the year.

V. Policy Recommendations for a New Refining Policy Path

Consumers want reliable and plentiful supplies of gasoline at reasonable prices. In order to satisfy these consumer demands while easing the pressure on existing domestic refineries and providing additional capacity to permit refiners to respond to emergencies, we must increase our domestic refining capacity. Unfortunately, this goal will be very difficult to accomplish.

Congress has a choice to make with respect to motor fuel refining policy. It can continue down the path followed for the past two decades. This path, as we have witnessed, results in static or reduced domestic refining capacity, balkanization of the motor fuel markets, increased imports, increased volatility in wholesale and retail prices, and rising costs for consumers. Over the past ten years, there has been disincentive for refiners to increase capacity due to the costs involved and the lack of opportunity to achieve a reasonable return on that investment.

Alternatively, we can embark on a different path. One that continues to encourage clean fuels. One that encourages, rather than discourages, expansion of domestic refining capacity. One that changes the fundamental economic calculus that a refiner makes when it decides whether to spend the huge sums necessary to make the upgrades required to produce clean fuels or to close the refinery.

NACS and SIGMA recommend that this Subcommittee consider three different, and yet related, areas of public policy for changing the path on which we currently travel. I will discuss each in turn.

A. Regulatory Reform

Currently, a disincentive exists for domestic refiners to add new capacity to their existing facilities. If they expand capacity, they expose themselves to the potential application of EPA's New Source Review ("NSR") regulations, which could impose tens of millions of dollars in additional environmental protection costs. NACS and SIGMA urge Congress and EPA to move forward with NSR reform that will continue to protect the environment while enabling facilities to expand capacity and satisfy consumer demand.

Second, it is virtually impossible to obtain the necessary federal and state permits to expand an existing refinery or build a new one. NACS and SIGMA urge Congress to streamline this process, without sacrificing environmental protections, to encourage, rather than discourage, the expansion of domestic refining capacity. Last month, the House passed H.R. 4517, a refinery revitalization bill sponsored by Chairman Barton which takes important steps toward streamlining the permitting process in certain circumstances. We supported that bill and urge Congress to expand its provisions to further incentivize the additional expansion of domestic refining capacity.

B. Incentivize Expansion of Refining Capacity

NACS and SIGMA posit that Congress should adopt federal tax code changes to incentivize domestic refiners to expand refining capacity. Such changes could include faster depreciation periods for refining assets, the ability to expense environmental upgrades investments when capacity also is expanded, or an investment tax credit aimed at encouraging the construction of new, state-of-the-art, clean fuels refineries. Whatever course Congress chooses to follow, it is clear that the status quo does nothing to encourage expansion of domestic refining capacity. If we want capacity to increase, then we must change the fundamental economics of such expansions.

C. Address "Boutique" Fuels

Additional refining capacity will go a long way to restoring the balance between supply and demand. However, additional capacity alone is not enough to reduce the incidence of regional supply shortages and price spikes. Expanding capacity will help the industry respond to outages, but the balkanization of our nation's motor fuel distribution system remains a major problem.

The proliferation of unique formulations of gasoline and diesel fuel, or "boutique" fuels, has destroyed the efficiencies of our nation's motor fuel distribution system. States and localities, in an effort to avoid the Reformulated Gasoline program and its oxygenate mandate, worked with their local refiners to develop fuels that would satisfy their air quality needs and fit the refiners' production streams. Unfortunately, no thought has been given to ensuring that the gasoline and diesel fuel supply remains fungible—or interchangeable—between markets.

The balkanization of our nation's fuels markets into distinct islands of boutique fuels must be stopped and, possibly, reversed. The first step toward achieving this goal is to repeal the federal reformulated gasoline program's oxygenate mandate.

This mandate is not necessary to improve air quality and has led many states to adopt boutique gasolines over the past decade in order to avoid being forced to bring MTBE or ethanol into their markets. A repeal of the RFG oxygenate mandate is contained in the conference report on H.R. 6, the national energy policy legislation. SIGMA and NACS strongly support H.R. 6 and urge its adoption before Congress adjourns for the year.

The second step towards stopping further balkanization is to prevent additional boutique fuels from being mandated in the future. Over the next several years, many states will submit plans to implement the new ozone clean air standard. Many of these state implementation plans likely will contain additional proposals to further balkanize the gasoline and diesel fuel markets through the adoption of new fuel blends developed to address local and regional air quality concerns. SIGMA and NACS posit that there already is an ample slate of fuel blends from which these states can choose to achieve their air quality needs. H.R. 4545, a boutique fuels moratorium bill introduced by Congressmen Blunt and Ryan last month and supported by SIGMA and NACS, would put a stop of the balkanization of these markets. Although this bill failed to receive the two-thirds majority required under suspension of the rules, it did receive a clear majority of support when considered on the House floor last month. We urge the House to revisit H.R. 4545 in the near future.

Both H.R. 6 and H.R. 4545 contain provisions that require federal agencies to study ways to reduce the number of boutique fuels that already exist in the market. We strongly support these studies, but caution again that there is no short-term fix to this problem. A NACS study on boutique fuels completed in 2003 demonstrated that reducing the number of fuels in the market will improve distribution efficiencies and facilitate the transfer of product between markets in order to respond to supply/demand imbalances. Fewer fuels reduces the stress on the pipeline system and improves the availability of product to specific markets.

Reducing the number of fuels, however, will reduce refining capacity. This is true because Congress must not allow any environmental backsliding and, therefore, any reduction in the number of fuels will result in a ratcheting down to the cleaner fuels in inventory. Each cleaner fuel is more complicated to produce and reduces the amount of gasoline available from each barrel of oil. Therefore, it is essential that Congress help expand domestic refining capacity in order to embark on a campaign to rationalize the motor fuels market.

The two track approach will provide significant benefits to the consumer. Gasoline and diesel fuel will be in greater supply throughout the nation and markets will be better able to efficiently and promptly respond to supply disruptions. The result will likely be less volatility in the marketplace with fewer regional shortages and price spikes.

VI. CONCLUSION

Mr. Chairman, once again I thank you for this opportunity to express the interests of NACS and SIGMA to this committee. I hope I have provided some fresh insight into the challenges facing the market today and will be happy to answer any questions that my testimony may have raised in your minds.

Mr. HALL. Thank you, Mr. Douglass. Well, we are down to the questions now.

Mr. Murti, as I read your testimony, you favor expanding—well, let me just start all over.

How many of you believe we need to expand domestic refining capacity? Raise your hands, please.

[Hands]

Everybody? We have an agreeable panel. How many of you believe legislation is needed for that to happen?

[Hands]

One, 2, 3, 4 of you. Mr. Murti, what is wrong with the legislation?

Mr. MURTI. It is not so much legislation, I think we just need to get to a condition where the return on capital in the refining industry is attractive enough, and that will then inspire companies to consider investing in new capacity. It is really a profitability question.

Mr. HALL. I liked your testimony, it was very helpful, but what is wrong with the legislation if we take into account the recommendations that this learned panel here has suggested?

Mr. MURTI. If one can legislate easing some of the permitting processes, that is fine, but you still need to have adequate profitability, that absolutely has to be the first step. And I don't think—and please forgive me if I am inaccurate—I don't think you can legislate better profitability unless you give these companies some minimum rate of return, which I don't think you are going to do.

All we would ask from a legislation standpoint would be to please not enact windfall profit taxes that takes away from profitability.

Mr. HALL. Well, you have hit on another situation there. Dr. Cooper, you proposed a windfall profits tax, I believe, did you not?

Mr. COOPER. I haven't proposed a windfall profits tax in my testimony for this committee the last two or three times I have testified. We have a different set of concerns. We want to reintroduce competition so we can get prices responding to competition.

Mr. HALL. But am I incorrect in saying you proposed a windfall profits tax to, as you said, I think, discourage profiteering?

Mr. COOPER. We have a severe concern about profiteering in the industry because of tight supplies. Our preferred approach is to find ways to introduce more competition. I don't believe this testimony supports windfall profits taxes. We would like to take the profit out of market manipulation, and if we can't get these firms behaving, then we have to look at that. But our primary objective is to have more competition.

Mr. HALL. As I read your statement, you said in a paragraph on page 6, "A windfall profits tax that kicks in under specific circumstances would take the fun and profit out of market manipulation" so, you, under some circumstances, recommend it?

Mr. COOPER. That is right, we want to take——

Mr. HALL. Because I want to ask you at what point, what figure, what dollar figure—you know, the old windfall profits tax was around, I think, $18 or $19—and what happens when it drops below that, and people who are producers are still stuck with all those expensive reporting things, reporting that they owe no—they weren't even able to do that in the 1980's. But your testimony was good, and we appreciate it.

I think my time—I have another minute left. Let me see if I have something else to ask. Mr. Murti, as I read your testimony, you favor expanding domestic refining capacity versus relying on imports, and I like that. You stated "jobs stay in the United States, product supply will be more reliable, greater assurance that the products will meet U.S. environmental standards"—is that an accurate summary of your statement? Do you want to expand on that?

Mr. MURTI. Yes, sir. If you rely on refined product imports, you then subject yourself to two sources of disruption, because these foreign refineries will also be relying on imported crude from geopolitically challenged areas, and we have already seen this happen.

When Venezuela shut its economy down due to a protest strike against President Chavez, you lost not only the crude supply from Venezuela, you lost the motor gasoline supply that came into our country from Venezuela. You also lost crude supply to a number of Caribbean refineries which then, in turn, had to reduce their gaso-

line supply to this country. So, you are still going to be dependent upon crude imports, but better to at least be dependent on only one potential source of disruption rather than two.

You also can't guarantee that foreign refineries will meet our environmental standards, and we are supportive of maintaining environmental standards. You just have to travel around the world to cities that don't have good environmental standards to appreciate what we do have here. And there is no guarantee a foreign refinery would meet our strict environmental standards.

Mr. HALL. We have smoked a "peace pipe" with Venezuela, though, and we are working on that. You are very accurate in pointing that out.

Mr. Douglass, as a purchaser of the refinery output, you feel we need more refineries, or need to enlarge the ones we have, what is your suggestion there?

Mr. DOUGLASS. Well, absolutely, we need more capacity. How that is done is up to the Congress and up to the individual investors, but if we got more supply, we have got obviously the stabilization of the market that, even when you have supply disruptions, you don't end up with in the shortfall—that is, markets that spike 50 and 60 cents a gallon because they have been cutoff by the supply system.

Mr. HALL. Thank you. My time is up. Recognize Mr. Green.

Mr. GREEN. Thank you, Mr. Chairman, and thank you again for calling the hearing.

Mr. Edwards, your testimony—and, of course, hearing the whole panel—I think what Valero has done is an example of mergers increasing capacity not only domestically, but offshore. I know in the testimony concerning Orion project or Orion facility in Louisiana, is it up and running now?

Mr. EDWARDS. Yes, it is. I think that is what my colleague pointed out, the Orion Refinery that had all the operating issues prior to us buying it. We have invested in reliability to make it more to where it operates onstream, and also to clean up some of the environmental problems they had in the past, and we are continuing that trend.

Mr. GREEN. And have you reached out to the fenceline folks, so to speak, or the people who may had a bad image of dealing with the earlier owners?

Mr. EDWARDS. We are really big into community relations, and we have had barbecues in the area with the public and the community, trying to win back the support that they had lost with the previous owner.

Mr. GREEN. I know I have a Valero Refinery in my area working with my community, and it has been a good experience in working together.

Mr. Murti, you talked about the need to add 260,000 barrels every 2 years, a new refinery every 2 years, or expansion. And I notice in the testimony earlier from Mr. Edwards, with the loss of MTBE we are going to lose about 300,000 barrels per day of premium blend stock, do you agree with that?

Mr. MURTI. Yes, sir. We think we have been actually optimistic in saying we only need 260,000 barrels a day of new refining capacity. We would assume, first of all, that rather than losing supply,

we actually have continued debottlenecking growth. Now, that has been the experience. So, as an analyst, we say we need to be proven otherwise before we stop assuming debottlenecking, but it is certainly possible, as the good folks at Valero suggest, that not only could you go from not having debottlenecking growth, but you could actually lose supply. And that will almost guarantee we will have an energy crisis in the very near future, rather than later on down the road.

Mr. GREEN. Mr. Slaughter, you testified that Congress should enact legislation that streamlines the permitting process, and I know that there is contradictory testimony, but for expansion projects, new refineries, and others—and you heard from my opening statement I am sympathetic to it—was the Refinery Revitalization Act the best answer, that we passed a couple of weeks ago, or should we focus our attention on expanding capacity in the existing refineries?

Mr. SCHAEFFER. Congressman Green, I think it was helpful in one direction. I think it indicated the House's interest in commitment to the domestic refining industry and expanding the domestic refining industry. As I mentioned in my oral statement, however, I think expansion of capacity of existing sites probably offers the most promise because that is a site that already has a refinery on it, you don't run into so many of the problems as you do with a completely new site and, historically, that is where the capacity additions have occurred.

Mr. GREEN. And I understand, at least in the facilities I represent, there is always an effort for debottlenecking. I mean, that is an ongoing process to see how much more you can get out of an existing facility with, again, maybe re-engineering or whatever.

Mr. SCHAEFFER. Mr. Green, if I could, I just wanted to mention that there has been mention of one project for building a new refinery in Arizona that is going on. They have been trying to get a permit there for 10 years, and they haven't got one yet. So, I think that puts into context why people are focusing on existing sites.

Mr. GREEN. Sounds like we need a pipeline from the Gulf Coast out there, but I worked on that in an earlier lifetime.

One of the concerns I have is the amount of—Mr. Slaughter, what countries do we actually receive refined products from now? Typically, I would say it is Venezuela, maybe Valero from—I don't know if Valero, in your Aruba facility, exports to the United States—but what countries do we have? Very little from the Middle East now.

Mr. SCHAEFFER. Well, there are some, as you pointed out, from Venezuela, from Brazil, we do get some cargoes from Europe sometimes, it varies—you know, areas like New England, the Northeast Coast, are essentially 20 percent dependent on imports to meet their supply. Across the U.S., the figure is less than that, but the East Coast is very heavily impacted by these imports, and we do have problems—for instance, early this year, apparently some of the sources did not invest in gasoline sulfur reduction so they could meet the new sulfur spec. So, there was some impact in reduced imports of gasoline for a period of time. And with an import dependence, those are essentially suppliers who look to see whether they have got a market opportunity here or not. And they also look

at other places in the world where gasoline demand is growing even faster than ours. They may decide not to make an investment and sell their product there.

Mr. GREEN. Mr. Cavaney, the Federal Clean Air Act of 1990 established the RFG Program requiring the Nation's most polluted cities to use 2 percent oxygenates. And I can tell you that at least in the Houston area, we have benefited from that. We know that Congress intended substantial use of MTBE which made great progress in the air quality, but again we found out that it is unpleasant to taste or smell, and water contamination associated with leaky storage tanks has resulted in a lot of defective product lawsuits against refiners.

How does the threat of defective product lawsuits against refiners for meeting the Government standard through the use of that Government requirement on product affect refining capacity or gasoline supply?

Mr. CAVANEY. Well, first of all, the Clean Air Act—you can go back and look at the record—required the use of an oxygenate, and it was clear from looking at the record at the time that the only volumes that could be created to satisfy that Government requirement was going to be MTBE principally, and to a much lesser degree ethanol. The use of that MTBE, in essence, then was known to everyone and was used by us. And now that it has been taken out of—by certain State actions—the mix, we are required to continue to use ethanol. And so there is a great deal of movement from ethanol in places where it is traditionally grown, using corn to the products.

Now, the thing that we are concerned about is that there is a whole flurry of lawsuits that claim that the industry should be held liable. And what that does is it adds yet further concern, looking to the future, about whether or not this is an industry that one ought to invest in because one only need look at other industries that have been faced with huge actions of this nature by trial lawyers, and you can see that it is an additional cloud.

The industry, if you look at the current law, anything that we spill in MTBE that we do, we are accountable for. Current law takes care of that. So, it is not anything to let us off the hook, but yet these lawsuits continue to pursue this particular thing.

Mr. GREEN. I don't mean to cut you off, but I am on a time limit. I know Mr. Douglass is representing convenience stores, and we have talked about the leaky storage tank that goes back to the refiners. In all honesty, we have been paying money into a trust fund to be able to correct that, and we are not utilizing as much as possible—and, again, I am almost out of even my extra 3 minutes, the chairman told me now as ranking member I have—but it is interesting because of the importation that you talked about, Mr. Slaughter, from Europe—and I know most European countries use MTBE—so if the New England States eliminate MTBE, then you have to find it somewhere else, or they produce it only for New England consumption.

Mr. Chairman, I appreciate your understanding, and look forward to additional questions if we have that time.

Mr. HALL. T note the presence of Mr. Waxman. Mr. Waxman, would you have any questions at all?

Mr. WAXMAN. I would like to have an opportunity.

Mr. HALL. The Chair recognizes the gentleman for 5 minutes.

Mr. WAXMAN. Thank you very much, Mr. Chairman. Mr. Schaeffer, I would like you to address a statement made by Mr. Cavaney from API. In his testimony, Mr. Cavaney said, "For years, getting permission to build a new refinery or expand existing refineries in the U.S. has been an extremely difficult, inefficient, and inordinately time-consuming process."

My understanding is that in recent years many refineries have simply ignored the permit requirements. Refineries have conducted major capacity expansion with significant increases in air pollution, but without applying for the New Source Review permits required under the Clean Air Act.

For years, you were in charge of EPA's effort to enforce these Clean Air requirements. Could you please address Mr. Cavaney's claim in light of the refineries' actual practices?

Mr. SCHAEFFER. Thank you for the opportunity to answer that question, Congressman. I think, first of all, the facts are the average refineries have—the ones that are still in existence now—have approximately doubled in size, and that is Department of Energy data.

We did find that a number of those capacity expansions were not permitted. We did issue some Notices of Violation, and we actually approached large companies like BP and Motiva, invited them into settlement discussion and, interestingly, in those conversations, we didn't hear a lot about the vagueness of New Source Review and the lack of certainty. We actually got right down to brass tacks and were able to negotiate, I think, some pretty successful settlements. BP and Motiva together are spending close to a billion dollars upgrading their plants and adding pollution controls. Companies like Exxon-Mobile, I think, following their long tradition, chose to fight instead. That is their right, of course, under the law. What concerns me is the Administration's failure to do any followup enforcement. And, again, you have the list in the attachment of cases that have been sitting now for 4, 5 and 6 years, with no action from the government.

Mr. WAXMAN. Mr. Schaeffer, Mr. Cavaney also claims that in areas not meeting the new National Air Quality Standards to protect human health from fine particulate matter, it will "be difficult or impossible to obtain construction and operating permits for expansions or new refineries."

What have we actually seen occur in nonattainment areas? Is there any basis whatsoever for claiming that it will be impossible for industry to expand?

Mr. SCHAEFFER. I don't think so. I think expansions have been fairly brisk in nonattainment areas, and that again is easily checked with the Department of Energy. I would point you to the Port Arthur-Beaumont areas where there are some significant expansions going on, and we could find other examples.

Mr. WAXMAN. Well, all evidence to the contrary, we are likely to continue to hear from the industry that environmental protections are to blame for high gas prices. No one claims that requirements to operate with less pollution are cost-free, but Americans have decided that they should be able to breathe the air and drink the

water without endangering their health and lives from avoidable industrial pollution.

I think we need to stop wasting our time and focus on the real energy challenges, how to manage and meet strongly rising demand for oil with supplies largely located in unstable areas, and the increasingly urgent problems of climate change.

Mr. Chairman, I would like to also ask unanimous consent to introduce the charts I used in my opening statement into the record, along with a Government Reform Committee report on oil dependence and the February EIA analysis of the Energy Bill.

Mr. HALL. Without objection. I thought Mr. Green had already done that.

Mr. GREEN. I was going to before we ended.

Mr. HALL. Without objection, they will be admitted.

Mr. WAXMAN. Thank you very much, Mr. Chairman.

[The EIA report submitted for the record is available at http://www.eia.doe.gov/oaif/servicerpt/pceb/pdf/sroiaf(2004)02.pdf and the Government Reform Committee report is available at http://www.house.gov/reform/min/pdfs__108__2/pdfs__inves__pdf__energy__national__energy__policy__oil__dep]

Mr. CAVANEY. Mr. Chairman, may I respond, since the question was pointed to me. First of all, we have not claimed that environmental costs are responsible for the very high prices. Appropriately, crude oil is the principal amount. Second largest component is taxes. It is a factor. The returns from the industry, as has been said by several of the panelists here, are historically low, well below the all-industry average. So, every little bit of extra cost that can be avoided or is not needed helps you be able to deliver the product. We do not argue that any environmental regulations be rolled back. There are honest differences on how you interpret them and, as was said, there is a system where you can approach those kind of things.

We feel that our viability of serving the consumer is that we want to have the minimum emissions that we can, consistent with providing health and have clean products, and we are working in that regard. I think our most recent regulatory work with EPA on the sulfur removal from diesel and non-road diesel, which was supported strongly by the environmental groups, by the municipalities, and all, is evidence of our interest in working toward having clean fuels, having a clean environment, but making sure that we have the kind of returns that are going to be necessary to invest and grow the capacity that people are needing.

Mr. WAXMAN. I appreciate your comments. Thank you, Mr. Chairman.

Mr. HALL. All right. That concludes our questions. I really want to thank this panel. At this time, the hearing is adjourned.

[Whereupon, at 2:40 p.m., the subcommittee was adjourned.]

[Additional material submitted for the record follows:]

August 17, 2004

The Honorable RALPH HALL
Chairman,
House Subcommittee on Energy and Air Quality
2125 Rayburn House Office Building
Washington, DC 20515

DEAR MR. CHAIRMAN: Thank you again for the opportunity to testify before the Subcommittee on Energy and Air Quality July 15, 2004, regarding the "Status of the U.S. Refining Industry." I hope my comments were informative and prove helpful as you consider issues affecting the petroleum industry.

In response to questions posed in your July 22, 2004, letter, I submit the following comments:

Question 1. Mr. Douglass, in your testimony you call for a moratorium on the creation of new boutique fuels. I understand that many States with ozone non-attainment areas are preparing implementation plans to comply with the new ozone air quality standard. Are you concerned that these new SIPs will contain mandates for new boutique fuels that will further balkanize the nation's gasoline and diesel fuel markets, making the price spikes we have seen recently more likely?

Response: That is precisely my concern. As more and more communities are designated in non-attainment, States will consider many strategies to bring their environmental performance into compliance with the new, more stringent ozone standard. In past SIP submissions, many States have opted to avoid the Federal Reformulated Gasoline program and its oxygenate mandate by adopting "boutique" fuel formations that are designed to meet their air quality needs but do not adequately take into account supply and distribution issues. This process has fragmented the nation's motor fuels distribution system, removing the efficiency and flexibility necessary to respond promptly to supply disruptions. The result has been an increase in the incidence of regional supply shortages and price spikes.

As States prepare their new SIPs, NACS and SIGMA believe there are sufficient fuel formulations currently in the market that can satisfy the compliance challenges posed by the new ozone standard. By requiring that States select from these currently available fuel blends rather than developing new formulations, Congress would prevent the further fragmentation of the gasoline refining and distribution system and prevent the current balkanization of the nation's gasoline marketers from becoming worse. This is a necessary first step towards rationalizing the gasoline distribution market and restoring fungibility to the system.

Question 2. Mr. Douglass, for several years witnesses before this Committee, including federal officials, analysts, refiner representatives, and your marketer organizations have identified boutique fuels as a prime cause in the gasoline price spike we have experienced in various regions of the country over the past five years. In your testimony, you advocate a moratorium on new boutique fuels and a study on rationalizing the number of fuels across the country. Shouldn't we be seeking to reduce the number of unique fuel blends across the country and restore fungibility between markets, rather than just imposing a moratorium on new boutique fuels?

Response: Restoring fungibility to the system in order to address the price spikes experienced throughout the country in recent years is a considerable challenge. Reducing the number of fuel blends permitted in the market would immediately restore a degree of fungibility and flexibility to the market, but at what cost?

According to a study released by NACS last year (Executive Summary attached), reducing the number of fuel blends in the market without backsliding on environmental protections will result in reduced domestic gasoline production capacity. This is true because as fuels are taken from the market, the remaining fuel blends must be the most environmentally friendly. These fuels, which require the removal of certain gasoline constituents to attain clean fuel standards, are more difficult to produce, yield fewer gallons from a barrel of oil, and are not available from all refineries.

Consequently, it is important that Congress understand fully the market implications of reducing the number of fuels in the market before it determines what would be an appropriate number of blends. For this reason, NACS and SIGMA advocate a multi-step approach:

1) Enact a moratorium on the approval of new fuel blends in order to stop the further proliferation of boutique fuels and do no additional harm to market fungibility;
2) Expand domestic refining capacity in order to enhance the industry's ability to satisfy consumer demand and to offset any lost capacity associated with a possible reduction in the number of fuel blends; and

3) Direct the Environmental Protection Agency and the Department of Energy to complete a comprehensive study to determine the most appropriate composition of the motor fuel inventory in the nation, with proper attention paid to supply availability and distribution fungibility. Such a study should return to Congress specific recommendations for legislative changes to the system.

Question 3. Mr. Douglass, what is the single most important action this Congress could take to both alleviate the pressure for new boutique fuels and reduce the number of boutique fuels nationwide?

Response: Congress must repeal the oxygenate mandate of the Clean Air Act's reformulated gasoline program. More than any other provision in the Clean Air Act, the oxygenate mandate has contributed to the proliferation of boutique fuels and the fragmentation of the nation's motor fuels distribution system as States have opted for their own boutique fuel programs rather than relying upon fuels containing either MTBE or ethanol. The time has come to repeal this provision. It has outlived its usefulness as advancements in gasoline formulations and engine performance have rendered it obsolete.

While NACS and SIGMA believe this is the most important action Congress can take, we disagree with some others in the industry who believe this is the only step Congress should take. Repealing the oxygenate mandate will significantly improve the market's performance, but it alone will not satisfy the long-term needs of the motor fuel production and distribution system. Congress must pursue a comprehensive approach to increased domestic refining capacity and restored supply fungibility. Repealing the oxygenate mandate is simply the necessary first step.

Question 4. Mr. Douglass, your testimony cites several statistics regarding the reduction in the number of domestic refineries and in domestic refining capacity. Your testimony calls for regulatory reform and tax incentives to stimulate the addition of domestic refining capacity. If Congress does not consider such proposals, are we as a nation going to become more dependent on imports of gasoline and diesel fuel in the future?

Response: Yes, if Congress fails to act the nation will become more dependent upon imported gasoline and diesel fuel. Consumer demand for motor fuels continues to grow, despite efforts to promote conservation. Without a coordinated strategy to expand domestic refining capacity, the gap between supply and demand will widen and the nation will increasingly look overseas to fill that gap.

We are already on the path to greater dependence on imports. This year, the nation is importing close to 1 million barrels of motor gasoline every day and the Energy Information Administration predicts that imports will account for at least 20 percent of our demand in 2025. Congress can improve the nation's energy security by encouraging an expansion of domestic refining capacity and reducing its reliance on imports.

Question 5. Mr. Douglass, if I understand your testimony, you are stating that our nation is at a cross-road when it comes to domestic refining capacity. We can continue on our current course and face ever increasing imports of gasoline and diesel fuel in the future. Alternatively, we can recognize the regulatory and financial challenges being faced by our nation's domestic refiners and pass legislation to alleviate these challenges while at the same time preserving our environmental protection laws. Is that correct?

Response: That is correct. Federal and state governments have enacted environmental protection laws and regulations that ignore the realities of the motor fuels production and distribution industry. Congress must change course if it wishes to promote domestic energy security and provide the transportation fuels vital for the economy. This does not mean that environmental protection goals should be ignored or discarded. Instead, it means that renewed attention must be paid to producing adequate domestic supplies of clean fuels.

In recent testimony, the refining industry has identified specific regulatory hurdles that have inhibited the expansion of refining capacity. Mr. Red Cavaney detailed on July 15 detailing the various regulatory impediments the industry faces. NACS and SIGMA believe that unless some balance is introduced into our regulatory system, the industry will continue invest its available capital in regulatory compliance upgrades rather than capacity expansion.

The refiners have also detailed the economic conditions impacting capacity expansion decisions. Mr. Murti testified July 15 that Wall Street typically requires at least a 10 percent return when reviewing investment opportunities. The refining sector typically earns a 5 percent return, far below the threshold reported by Mr. Murti. This is an impediment to refinery capacity expansion and demonstrates the need for Congress to consider incentivizing expansion projects.

Congress does have a decision to make. It can continue pursuing an environmental agenda that pays no heed to energy and economic realities and increases our

reliance on imported product, or it can seek a balanced agenda that promotes environmental protections while supporting the energy and economic interests of the nation.

Question 6. Mr. Douglass, you state in your testimony that the marketer groups you represent support environmental protection programs. I think I hear you asserting that affordable and plentiful supplies of gasoline and diesel fuel do not have to come at the price of environmental protection. Do you believe that the proposals you are advancing can be achieved without sacrificing the significant advances our nation has made in improving our air quality and producing cleaner gasoline and diesel fuel?

Response: Yes, I do believe that the nation can expand refining capacity and restore fungibility to the marketplace without sacrificing environmental protections. It is a question of balance, and Congress must take a careful look at all aspects of the policies it promotes. Focusing on only one segment of the issue, whether it be supply availability or environmental protections, without regards to the other is short-sighted and doomed to failure. The supply-oriented proposals I outlined in my testimony were influenced by the assumption that environmental quality will be protected.

Congress must promote a balanced approach to motor fuels policy that continues to advance the cause of clean air while ensuring that America's consumers can access the vital resources of gasoline and diesel fuel.

Mr. Chairman, thank you again for the opportunity to present the views of NACS and SIMGA to the Subcommittee. If you have any additional questions, please do not hesitate to contact me.

Sincerely,

BILL DOUGLASS
CEO, Douglass Distributing Company

cc: The Honorable John Sullivan

MOTOR FUELS SUPPLY FUNGIBILITY AND MARKET VOLATILITY ANALYSIS

EXECUTIVE SUMMARY

Produced for: National Association of Convenience Stores

In 1990, gasoline sold in the United States was distinguished only by three grades (regular, midgrade and premium) and volatility restrictions in two geographies (northern and southern) and two seasons (winter and summer). Today, the number of different U.S. gasoline blends has increased to no fewer than 15 (excluding the various octane grades). These new and varied gasoline formulations have proliferated over the intervening years primarily due to more restrictive federal, state and local air quality standards

In late 2002, the National Association of Convenience Stores (NACS) asked Hart Downstream Energy Services (Hart) to conduct a comprehensive analysis of the current gasoline market situation in the United States. NACS inquired about potential problems associated with the continued proliferation of unique, non-fungible federal, state and local fuel blends—commonly referred to as "boutique fuels." NACS requested Hart to analyze the current impact these boutique fuels are having on national and regional markets in the United States and the refining industry's ability to produce, distribute and deliver sufficient quantities of these fuels to the consuming public.

In particular, NACS was interested in assessing the impact of various regulatory scenarios on four primary criteria: overall gasoline supply, gasoline fungibility, ultimate costs to the consumer and environmental quality. To lay the foundation for this analysis, NACS requested that Hart examine the following eight cases:

- *Baseline Analysis 2001:* A characterization of the current "state of the refining industry" in terms of regional gasoline supply, demand and quality, and overall refining operations and production capability.
- *Baseline Analysis 2007:* Extends the 2001 Baseline through 2007 incorporating those market, regulatory and refining changes that are expected to occur. Baseline 2007 assumes state bans of MTBE in California, Connecticut and New York are implemented, the RFG oxygen standard remains in place and no renewable fuel standard is imposed. In addition, this Baseline assumes the implementation of Tier 2 sulfur standards for gasoline, the Mobile Source Air Toxics (MSAT) program and the ultra-low sulfur diesel rule

- *Flex Case 1—No MTBE Bans:* Models market conditions if California, Connecticut and New York did not ban MTBE. Assumes the RFG oxygen standard remains in place and no renewable fuel standard.
- *Flex Case 2—Based on House Energy Bill (H.R. 6):* Assumes implementation of an MTBE ban in California, Connecticut and New York, without the RFG oxygen standard in place and with implementation of a renewable fuel standard.
- *Flex Case 3—Based on Senate Energy Bill (S. 14):* Assumes a Federal MTBE ban, without the RFG oxygen standard and with implementation of a renewable fuel standard.
- Flex Case 4—Four Fuels Program: Assumes a Federal MTBE ban, with the RFG oxygen standard in place and no renewable fuel standard. Conventional gasoline RVP grades are consolidated into one RVP grade. All RFG is consolidated into a single oxygen content grade.
- *Flex Case 5—Regional Fuels Program:* Assumes implementation of an MTBE ban in California, Connecticut and New York, without the RFG oxygen standard in place and with implementation of a renewable fuel standard. Conventional gasoline RVP grades are consolidated into two RVP grades in each PADD (7.0 and 9.0 psi for PADDs 1, 3, 5 and 9.0 psi for PADD 2).
- *Flex Case 6—RFG Only Program:* Assumes implementation of an MTBE ban in California, Connecticut and New York, without the RFG oxygen standard in place and no renewable fuel standard. Conventional gasoline is consolidated to meet RFG specifications.

Current Market Conditions

A comparison of the various U.S. summertime gasoline blends currently required in different parts of the country shows that the top four summertime blends represent approximately 83 percent of the U.S. gasoline market, while most blends are much less common, interchangeable and fungible; each representing only a small market, as well as a small portion of the U.S. gasoline pool.

Most of these gasoline blends are not fully fungible with other gasoline blends for a variety of reasons, including:

- Gasoline blended with ethanol cannot be mixed with other gasoline blends in the common carrier pipeline system or gasoline storage tanks.
- Low-RVP gasolines, while providing a less expensive way than RFG for localities to obtain air quality improvements, place additional strain on the distribution system.
- Seasonal changes to gasoline formulations (i.e. winter-to-summer transition) can reduce refiner flexibility, gasoline fungibility and distribution efficiency.
- Market-specific fuel requirements often prohibit the transfer of product from one region to another, thereby exacerbating gasoline shortages and regional price increases during supply disruptions.
- Segmenting the U.S. gasoline system means that fewer domestic and international refiners are able to provide product meeting the various clean-fuel requirements. This limitation on available gasoline supply prevents rapid response from neighboring refineries and/or gasoline terminals in the event of a capacity shortage, further pressuring the refining system and driving up gasoline prices.

Further complicating the boutique fuel issue is the overall reduction in U.S. refining capacity. Since 1981, the total number of refineries in the U.S. has fallen from 324 to only 149. Meanwhile, domestic refineries operate today at approximately 93 percent of maximum capacity.

Net oil imports are expected to increase from about 55 percent of U.S. oil consumption in 2001, to approximately 68 percent by 2025. Additionally, U.S. gasoline consumption is projected to rise from 8.7 million barrels per day in 2001 to 13.8 million barrels per day in 2025, with gasoline imports continuing to increase. Today, more than five percent of America's motor gasoline supply is imported; nearly all of that directly to the Northeast market.

Considering the nation's maximized operational capacity, increased reliance on imported oil, and strained refining infrastructure, any complicating factors in the gasoline distribution chain, refining outages, or multiple small-market fuel formulations can easily impact overall supply and consumer costs. Further, overall gasoline demand is expected to continue to grow at rates greater than two percent annually over the near-term, particularly in the Northeast U.S.—one of the regions most sensitive to gasoline supply volatility and price impacts due to its reliance on imports.

Many in the refining industry, environmental community, and government, as well as consumer groups, have called for a reasonable, gradual and consistent approach to implementing fuels standards.

Summary of Findings

Recognizing the ongoing public policy debate over fuels issues, NACS requested an examination of several possible real-world scenarios that would potentially impact current U.S. gasoline supply, distribution and delivery. The following summaries outline the impact on gasoline supply compared to the projected production capacity of Base Case 2007. Analyzing such production capacities provides valuable insight into the potential balance between supply and demand and the nation's projected reliance on imported gasoline, each of which can ultimately influence consumer costs.

While striving to preserve current air quality (a prerequisite in any fuels regulatory endeavor), the models produced two generally competing findings that should be carefully balanced in any future policy changes to the U.S. gasoline system: 1). Overall reduction in the number of gasoline formulations required throughout the nation can be expected to improve overall system fungibility and potentially reduce marketplace volatility associated with boutique fuels; and 2). Decreasing the number of fuel formulations reduces the domestic refining system's capacity to produce compliant fuels.

In general, findings included:

Production

- *Base Case 2007:* Growth in gasoline demand will continue to outpace domestic refining production capability. By 2007 the domestic gasoline shortfall (or reliance on imported product) will increase by 987 thousand barrels per day over 2001. Refinery capacity expansion will be necessary and utilization will approach the maximum.
- *Flex Case 1—No MTBE Bans:* Gasoline production is 2.4 percent higher from the Baseline 2007. With no state MTBE bans, total MTBE use increased by 160 thousand barrels per day and ethanol use decreased by 65 thousand barrels per day.
- *Flex Case 2—Based on House Energy Bill (H.R. 6):* Gasoline production is reduced 0.6 percent from Baseline 2007. With state MTBE bans as in Baseline 2007, with an RFS, but with no oxygen standard, MTBE blending is reduced by 35 thousand barrels per day versus the Baseline and ethanol increased by 50 thousand barrels per day to satisfy the renewable standard.
- *Flex Case 3—Based on Senate Energy Bill (S. 14):* Gasoline production is reduced 5 percent from Baseline 2007. This case examined a national MTBE ban, coupled with an RFS and no oxygen standard. This resulted in the removal of 160 thousand barrels per day of MTBE from the gasoline pool. Ethanol use is roughly the same as Flex Case 2 to satisfy the renewable standard.
- *Flex Case 4—Four Fuels Program:* Total gasoline production is reduced 16 percent from Baseline 2007. In this Flex Case, ethanol must be used in RFG to satisfy the RFG oxygen requirement, which remains in place. Gasoline production capability is further curtailed as a result of the additional requirement to lower the RVP of a large portion of the conventional gasoline.
- *Flex Case 5—Regional Fuels Program:* Gasoline production is reduced 4.5 percent from Baseline 2007. This case considers the state MTBE bans and the oxygen standard of Flex Case 2. The additional requirement to consolidate conventional gasoline by reducing RVP of the higher volatility grades further reduces gasoline production (beyond Flex Case 2) by about 330 thousand barrels per day.
- *Flex Case 6—RFG Only Program:* Gasoline production capability is reduced by about 9 percent over the 2007 Baseline. This Case represents the state MTBE bans without an RFG oxygen or renewable fuel standard. In addition, all gasoline is produced at RFG quality. The RFG requirements result in slightly higher ethanol use to ensure RFG quality. The more stringent RFG standards severely constrain gasoline production capability. However, increased MTBE use outside the ban areas makes up volume and minimizes production loss. Total MTBE use was 275 thousand barrels per day (only 115 thousand barrels per day above Baseline 2007).

These findings demonstrate that all future regulatory scenarios to a varying degree have the potential to reduce the nation's ability to produce sufficient quantities of gasoline to meet demand and, consequently, to increase the nation's reliance on gasoline imports. The analysis indicates that, under the given conditions, Flex Case 1 would have the most positive impact on the nation's supply balance while Flex Case 4 would have the worst impact. The Flex Cases rank according to the 2007 Base Case as shown in Table 1.

Table 1: Gasoline Production, Imports and Percent Change in Flex Cases

Case	Net Production (MBPD)	Incremental Imports Needed (MBPD	% Change in Production Relative to Baseline
2007 Baseline	7,915	-	-
Flex Case 1	8,107	-192	2.4%
Flex Case 2	7,864	51	-0.6%
Flex Case 5	7,560	355	-4.5%
Flex Case 3	7,513	402	-5.1%
Flex Case 6	7,217	698	-8.8%
Flex Case 4	6,672	1243	-15.7%

This analysis further provides an indication of how each Flex Case may impact the ultimate price paid by the consumer. In general, the more out of balance the supply-demand relationship, and the greater the nation's reliance on imported gasoline, the more susceptible the consumer will be to higher gasoline prices. To this end, it can be assumed that the same rankings applied to production capacity and import reliance could also be applied to anticipated consumer prices.

Fungibility

Assuming the environmental impact of each Flex Case is constant or improved over Base Case, the final criteria of concern remains gasoline fungibility. An analysis of the Flex Case descriptions renders the following comparison in terms of impact on fungibility:

- *Flex Case 1—No MTBE Bans:* Improves fuel fungibility and overall product availability by eliminating the pending California, New York and Connecticut bans on the fuel additive MTBE. In the Northeast, the product distribution infrastructure will be less stressed by not having to deliver segregated MTBE- and non-MTBE-gasolines to various markets in the region. In addition, the market will not have to accommodate two distinct oxygenates, one of which (ethanol) cannot be shipped in the pipeline. California likewise will not have to transport an oxygenate outside of the pipeline and will experience improved fungibility over Base Line.
- *Flex Case 2—Based on House Energy Bill (H.R. 6):* Loosely modeled on the House passed energy bill (H.R. 6), this case examines an elimination of the RFG oxygenate mandate and an implementation of a renewable fuels standard. Like Base Line 2007, state MTBE bans remain in place, which reduces fungibility. The repeal of the oxygenate mandate could add additional flexibility to the system, but the presence of oxygenated and non-oxygenated RFG could also pose a fungibility challenge as the two fuels may not be commingled in storage tanks.
- *Flex Case 3—Based on Senate Energy Bill (S. 14):* Loosely modeled on the Senate energy bill (S. 14), this case is similar to Flex Case #2 with the exception of a national ban on MTBE. The legislation simplifies the distribution system by removing the state-by-state bans on MTBE, thereby restoring fungibility.
- *Flex Case 4—Four Fuels Program:* Along with Flex Case #6, perhaps the most fungible of the cases modeled, this case includes a national ban of MTBE, thereby removing the distribution challenges imposed by independent state actions. In addition, the model consolidates all conventional gasoline into one RVP grade and yields only one RFG formulation—ethanol-RFG. Distribution challenges arise with the delivery of ethanol throughout the nation.
- *Flex Case 5—Regional Fuels Program:* Establishes a regional fuels program that will improve fungibility within each PADD, consolidating conventional gasoline to two RVP formulations and RFG, thereby simplifying the distribution system and restoring a large degree of fungibility.
- *Flex Case 6—RFG Only Program:* Along with Flex Case #4, perhaps the most fungible of the cases modeled, this case eliminates all conventional gasoline and creates a market in which only RFG (northern, southern and California) is allowed in the market. Ethanol- and MTBE-RFG markets are regionally segregated, thereby limiting the distribution challenges to accommodate these two fuels.

The above analysis clearly indicates that restoring fungibility to the system will require a compromise in terms of production capacity and reliance on foreign product. As the more fungible cases were run through the model, production capacity of the domestic refining industry was sacrificed. The two most fungible cases (#4 and #6) produced the greatest reduction in production capacity and reliance on im-

ported gasoline. The case with the most positive impact on production capacity (#1) is likely politically unrealistic due to current debate over the expanded use of ethanol and restricted use of MTBE.

The challenge for developing a new fuels program is to simultaneously assess the impact on production capacity with that of fungibility and determine the best overall solution for the market. This report provides the foundation for such an analysis.

Based on these findings, NACS presents to policymakers the following fundamental concepts that must be addressed when developing a comprehensive fuels policy:

1) Recognize that fuel "Balkanization" is a growing problem that contributes to price volatility;
2) Acknowledge that domestic gasoline supply will continue to contract;
3) Ensure that imports of finished gasoline are not restricted;
4) Develop a coordinated refining industry policy to promote domestic capacity expansion; and
5) Develop a coordinated distribution infrastructure policy to facilitate the efficient delivery of product to retail.

NACS looks forward to working closely with the policymakers and other leaders in the fuel refining and distribution system to develop a coordinated, thoughtful approach that ensures government and industry work together toward a reasonable motor fuels policy.

United States Government Accountability Office

GAO

Testimony

Before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, House of Representatives

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ENERGY MARKETS

Mergers and Other Factors that Affect the U.S. Refining Industry

Statement of Jim Wells, Director
Natural Resources and Environment

GAO-04-982T

Mr. Chairman and Members of the Subcommittee:

We are pleased to be here today to participate in discussing issues related to the "Status of the U.S. Refining Industry." Refining transforms crude oil into a wide range of petroleum products, with gasoline accounting for about half of U.S. refinery output.

Data from the Energy Information Administration (EIA) indicate that there are currently 149 refineries in the United States with a total crude oil distillation capacity of about 16.9 million barrels per day. As we testified in 2001, each day vehicles in the United States consume about 10 million barrels of petroleum fuels, primarily gasoline and diesel, and according to projections, the figure will rise to about 15 million barrels per day by 2010, raising concerns about our ability to satisfy this growing demand. According to the United States Energy Association, no new major refinery has been built on the U.S. mainland in the last 25 years, and the nation's overall distillation capacity has declined more than 10 percent since the peak in 1981.

Concerns have also been raised about recent price increases for gasoline. EIA data show that the average retail price for regular gasoline (the type of gasoline used most in the United States) recently hit a nationwide high of $2.06 cents/gallon by the end of May 2004, an increase of about 58 cents/gallon or 39 percent over the same time last year. In some parts of the country, such as the West Coast, gasoline prices reached an average of $2.34 cents/gallon by the end of May 2004, an increase of about 65 cents/gallon or 38 percent over the same time last year. Although prices have recently begun to fall, elevated gasoline prices can be an economic burden to American consumers and the economy.

A broad range of factors affects gasoline prices and its volatility. These factors typically include changes in crude oil costs, refinery capacity, inventory levels relative to demand, supply disruptions, and regulatory factors—such as many different gasoline formulations that are required to meet varying federal and state environmental laws. Federal and state taxes are also a component of U.S. gasoline prices, but these do not fluctuate often. We have addressed many of these issues in several studies on energy markets. Among other things, our past studies showed that

- the U.S. economy is vulnerable to oil supply disruptions and options were identified to mitigate their effects;

- the Clean Air Act specifically requires refiners to produce reformulated gasoline, and the requirement to provide a specific blend for a specific area can present challenges to refiners and other suppliers if there are supply disruptions;

- most spikes in gasoline prices appear to result from such factors as increases in world crude oil prices, unexpected refinery outages, or larger-than-expected increase in demand; and

- gasoline price spikes were generally higher in California from January 1995 through December 1999 than in the rest of the nation, partly because there were unplanned refinery outages and it was difficult to substitute for the loss of supply of CARB, the special reformulated gasoline used in California.

Market consolidation is another factor that can affect the price of gasoline. Our testimony today will focus on our recent study that examined the effects of market consolidation—including increased market concentration in refining—and other factors related to the U. S. petroleum industry.[1]

Since the 1990s, the U.S. petroleum industry has experienced a wave of mergers, acquisitions, and joint ventures, several of them between large oil companies that had previously competed with each other for the sale of petroleum products.[2] A few examples include the merger between British Petroleum (BP) and Amoco in 1998 to form BPAmoco, which later merged with ARCO, and the merger in 1999 between Exxon, the largest U.S. oil company, and Mobil, the second largest. In general, mergers raise concerns about potential anticompetitive effects on the U.S. petroleum industry and ultimately on gasoline prices because mergers could result in greater market power for the merged companies, potentially allowing

[1]See U.S. General Accounting Office, *Energy Markets: Effects of Mergers and Market Concentration in the U.S. Petroleum Industry*, GAO-04-96 (Washington, D.C., May 17, 2004). Additional related GAO studies include *U.S. Ethanol Market: MTBE Ban in California*, GAO-02-440R (Washington, D.C., Feb. 27, 2002); *Alternative Motor Fuels and Vehicles: Impact on the Transportation Sector*, GAO-01-957T (Washington, D.C., July 10, 2001); *Motor Fuels: California Gasoline Price Behavior*, GAO/RCED-96-121 (Washington, D.C., Apr. 28, 2000); *International Energy Agency: How the Agency Prepares Its World Market Statistics*, GAO/RCED-99-142 (Washington, D.C., May 7, 1999); and *Energy Security: Evaluating U.S. Vulnerability to Oil Supply Disruptions and Options for Mitigating Their Effects*, GAO/RCED-97-6 (Washington, D.C., Dec. 12, 1996).

[2]We refer to all of these transactions as mergers.

them to increase prices above competitive levels.[3] On the other hand, mergers could also yield cost savings and efficiency gains, which may be passed on to consumers in lower prices. Ultimately, the impact depends on whether market power or efficiency dominates.

Our report examined mergers in the U.S. petroleum industry from the 1990s through 2000; the changes in market concentration (the distribution of market shares among competing firms) in the different segments, including refining, and other factors affecting competition in the U.S. petroleum industry; how U.S. gasoline marketing has changed since the 1990s; and how mergers and market concentration in the U.S. petroleum industry have affected U.S. gasoline prices at the wholesale level.

To address these issues, we purchased and analyzed a large body of data on mergers and wholesale gasoline prices, as well as data on other relevant economic factors, including refinery capacity. We also developed econometric models for examining the effects of eight specific mergers and increased market concentration on U.S. wholesale gasoline prices nationwide. It is noteworthy that using econometric models allowed us to measure the effects of mergers and market concentration while isolating the effects of several other factors that could influence wholesale gasoline prices, such as world crude oil costs, limited refining capacity, or low inventories relative to demand. For our market concentration model, we used concentration data measured at the refining level. We believe that the source of potential market power in the wholesale gasoline market is at the refining level because the refinery market is imperfectly competitive and refiners essentially control gasoline sales at the wholesale level.

In the course of our work, we consulted with Dr. Severin Borenstein,[4] a recognized expert in the modeling of gasoline markets; interviewed officials across the industry spectrum; and reviewed relevant economic literature and numerous related studies. We also used an extensive peer review process to obtain comments from experts in academia and relevant

[3]Federal Trade Commission and Department of Justice have defined market power for a seller as the ability profitably to maintain prices above competitive levels for a significant period of time.

[4]Dr. Borenstein is E.T. Grether Professor of Business Administration and Public Policy at the Haas School of Business, University of California, Berkeley. He is also the Director of the University of California Energy Institute.

government agencies. We conducted our work in accordance with generally accepted government auditing standards.

In summary, we found the following:

- Over 2,600 mergers occurred in the petroleum industry from 1991 through 2000, mostly during the second half of the decade. Petroleum industry officials cited various reasons for this wave of mergers, particularly the need for increased efficiency and cost savings. Economic literature suggests that firms also sometimes use mergers to enhance their market power. Ultimately, the reasons cited by both sources generally relate to the merging companies' desire to maximize profit or shareholder wealth.

- Market concentration, which is commonly measured by the Herfindahl-Hirschman Index (HHI), has increased in the downstream (refining and marketing) segment of the U.S. petroleum industry since the 1990s, partly as a result of merger activities, while changing very little in the upstream (exploration and production) segment. Of particular interest to this subcommittee, market concentration in refining increased, although the levels as well as the changes varied geographically. For example, market concentration in refining increased from moderately to highly concentrated in the East Coast and from unconcentrated to moderately concentrated in the West Coast; it increased but remained moderately concentrated in the Rocky Mountain region. Concentration in the wholesale gasoline market increased substantially from the mid-1990s so that by 2002, most states had either moderately or highly concentrated wholesale gasoline markets. Anecdotal evidence suggests that mergers may also have affected other factors that impact competition, such as the ability of new firms to enter the market.

- According to industry officials, two major changes have occurred in U.S. gasoline marketing since the 1990s, partly related to mergers. First, the availability of unbranded (generic) gasoline has decreased substantially. Unbranded gasoline is generally priced lower than branded gasoline, which is marketed under the refiner's trademark. Industry officials generally attributed the decreased availability of unbranded gasoline to, among other factors, a reduction in the number of independent refiners that typically supply unbranded gasoline. Second, industry officials said that refiners now prefer dealing with large distributors and retailers. This preference, according to the officials, has motivated further consolidation in both the distributor and retail markets, including the rise of hypermarkets—a relatively new breed of gasoline market participants that includes such large retail warehouses as Wal-Mart and Costco.

- Our econometric analyses, using data from the mid-1990s through 2000, show that oil industry mergers generally led to higher wholesale gasoline prices (measured in our report as wholesale prices less crude oil prices), although prices sometimes decreased. Six of the eight specific mergers we modeled—which mostly involved large, fully vertically integrated companies—generally resulted in increases in wholesale prices for branded and/or unbranded gasoline of about 2 cents per gallon, on average. Two of the mergers generally led to price decreases averaging about 1 cent per gallon. The preponderance of price increases over decreases indicates that the market power effects, which tend to increase prices, for the most part outweighed the efficiency effects, which tend to decrease prices.

- Our econometric analyses also show that increased market concentration, which captures the cumulative effects of mergers as well as other market structure factors, also generally led to higher prices for conventional gasoline and for boutique fuels—gasoline that has been reformulated for certain areas in the East Coast and Gulf Coast regions and in California to lower pollution. The price increases were particularly large in California, where they averaged about 7 cents per gallon.

- Higher wholesale gasoline prices were also a result of other factors: high refinery capacity utilization rate; low gasoline inventories, which typically occur in the summer driving months; and supply disruptions, which occurred in the Midwest and on the West Coast. We identified price increases of one-tenth of 1 cent to 7 cents per gallon that were caused by other factors included in our models—particularly low gasoline inventories relative to demand, high refinery capacity utilization rates, and supply disruptions that occurred in some regions. For example, we found that a 1 percent increase in refinery capacity utilization rates resulted in price increases of one-tenth to two-tenths of a cent per gallon. We found that prices were higher because higher refinery capacity utilization rates leave little room for error in predicting short-run demand. During the period of our study, refinery capacity utilization rates at the national level averaged about 94 percent per week. Just last week, DOE testified that U.S. refineries are running at near total capacity of about 96 percent.

As I noted earlier, we used extensive peer review to obtain comments from outside experts, including FTC and EIA, and we incorporated those comments as appropriate. FTC disagreed with our methodology and findings and provided extensive comments, which we have addressed in our report. Our findings are generally consistent with previous studies of the effects of specific oil mergers and of market concentration on gasoline prices. We believe, however, that ours is the first comprehensive study to

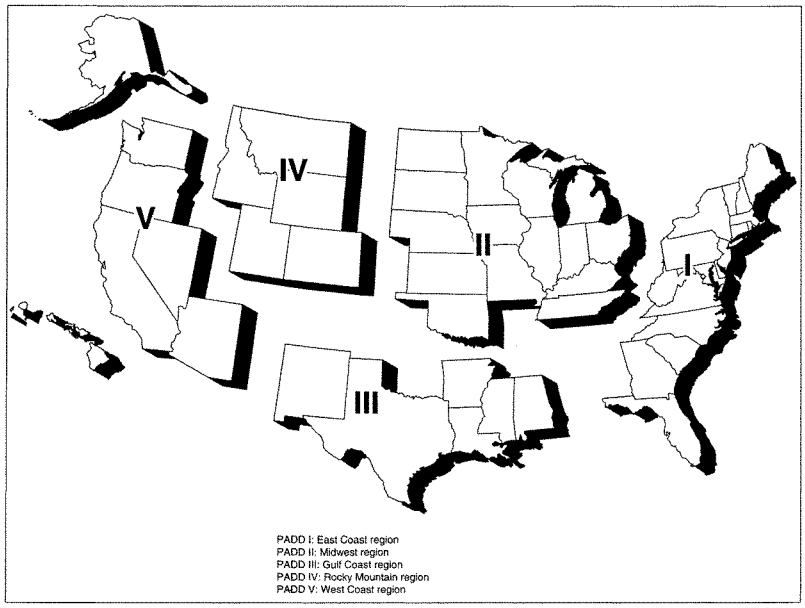
model the impact of the industry's 1990s wave of mergers on wholesale gasoline prices for the entire United States, an effort that required us to acquire large datasets and perform complex analyses.

Background

Many firms of varying sizes make up the U.S. petroleum industry. While some firms engage in only limited activities within the industry, such as exploration for and production of crude oil and natural gas or refining crude oil and marketing petroleum products, fully vertically integrated oil companies participate in all aspects of the industry. Before the 1970s, major oil companies that were fully vertically integrated controlled the global network for supplying, pricing, and marketing crude oil. However, the structure of the world crude oil market has dramatically changed as a result of such factors as the nationalization of oil fields by oil-producing countries, the emergence of independent oil companies, and the evolution of futures and spot markets in the 1970s and 1980s. Since U.S. oil prices were deregulated in 1981, the price paid for crude oil in the United Stated has been largely determined in the world oil market, which is mostly influenced by global factors, especially supply decisions of the Organization of Petroleum Exporting Countries (OPEC) and world economic and political conditions.

The United States currently imports over 60 percent of its crude oil supply. In contrast, the bulk of the gasoline used in the United States is produced domestically. In 2001, for example, gasoline refined in the United States accounted for over 90 percent of the total domestic gasoline consumption. Companies that supply gasoline to U.S. markets also post the domestic gasoline prices. Historically, the domestic petroleum market has been divided into five regions: the East Coast region, the Midwest region, the Gulf Coast region, the Rocky Mountain region, and the West Coast region. (See fig. 1.) These regions are known as Petroleum Administration for Defense Districts (PADDs).

Figure 1: Petroleum Administration for Defense Districts



Source: EIA.

Proposed mergers in all industries, including the petroleum industry, are generally reviewed by federal antitrust authorities—including the Federal Trade Commission (FTC) and the Department of Justice (DOJ)—to assess the potential impact on market competition. According to FTC officials, FTC generally reviews proposed mergers involving the petroleum industry because of the agency's expertise in that industry. FTC analyzes these mergers to determine if they would likely diminish competition in the

relevant markets and result in harm, such as increased prices. To determine the potential effect of a merger on market competition, FTC evaluates how the merger would change the level of market concentration, among other things. Conceptually, the higher the concentration, the less competitive the market is and the more likely that firms can exert control over prices. The ability to maintain prices above competitive levels for a significant period of time is known as market power.

According to the merger guidelines jointly issued by DOJ and FTC, market concentration as measured by HHI is ranked into three separate categories: a market with an HHI under 1,000 is considered to be unconcentrated; if HHI is between 1,000 and 1,800 the market is considered moderately concentrated; and if HHI is above 1,800, the market is considered highly concentrated.[5]

While concentration is an important aspect of market structure—the underlying economic and technical characteristics of an industry—other aspects of market structure that may be affected by mergers also play an important role in determining the level of competition in a market. These aspects include barriers to entry, which are market conditions that provide established sellers an advantage over potential new entrants in an industry, and vertical integration.

Mergers Occurred in All Segments of the U.S. Petroleum Industry in the 1990s for Several Reasons

Over 2,600 merger transactions occurred from 1991 through 2000 involving all three segments of the U.S. petroleum industry. Almost 85 percent of the mergers occurred in the upstream segment (exploration and production), while the downstream segment (refining and marketing of petroleum) accounted for about 13 percent, and the midstream segment (transportation) accounted for over 2 percent. The vast majority of the mergers—about 80 percent—involved one company's purchase of a segment or asset of another company, while about 20 percent involved the acquisition of a company's total assets by another so that the two became one company. Most of the mergers occurred in the second half of the decade, including those involving large partially or fully vertically integrated companies.

[5]HHI is calculated by summing the squares of the market shares of all the firms within a given market.

Petroleum industry officials and experts we contacted cited several reasons for the industry's wave of mergers in the 1990s, including achieving synergies, increasing growth and diversifying assets, and reducing costs. Economic literature indicates that enhancing market power is also sometimes a motive for mergers. Ultimately, these reasons mostly relate to companies' desire to maximize profit or stock values.

Mergers Contributed to Increases in Market Concentration and to Other Changes That Affect Competition

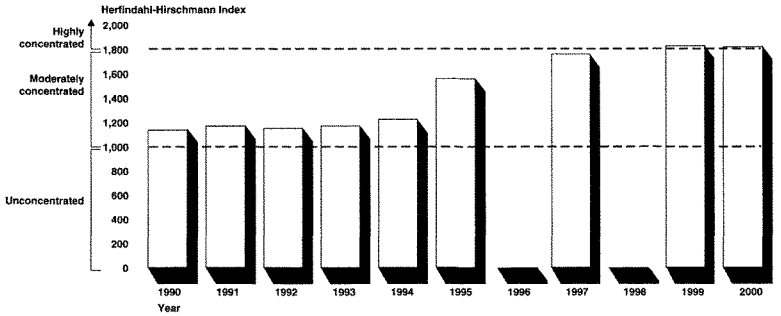
Mergers in the 1990s contributed to increases in market concentration in the downstream (refining and marketing) segment of the U.S. petroleum industry, while the upstream segment experienced little change.

Overall, the refining market experienced increasing levels of market concentration (based on refinery capacity) in all five PADDs during the 1990s, especially during the latter part of the decade, but the levels as well as the changes of concentration varied geographically.

In PADD I—the East Coast—the HHI for the refining market increased from 1136 in 1990 to 1819 in 2000, an increase of 683 (see fig. 2). Consequently, this market went from moderately concentrated to highly concentrated. Compared to other U.S. PADDs, a greater share of the gasoline consumed in PADD I comes from other supply sources—mostly from PADD III and imports—than within the PADD. Consequently, some industry officials and experts believe that the competitive impact of increased refiner concentration within the PADD could be mitigated.[6]

[6]However, if the same PADD I refiners are also mostly responsible for importing gasoline into the PADD, it could have implications for the PADD's wholesale gasoline market concentration. In addition, the extent to which these companies control vital infrastructure, such as terminals and pipelines, within the region could impact competitive conditions.

Figure 2: Refining Market Concentration for PADD I Based on Crude Oil Distillation Capacity (1990-2000)

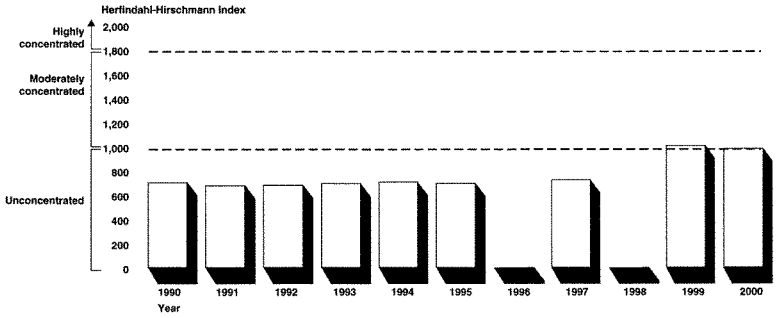


Source: GAO analysis of EIA data.

Note: Data for 1996 and 1998 were unavailable.

For PADD II (the Midwest), the refinery market concentration increased from 699 to 980 —an increase of 281—between 1990 and 2000. However, as figure 3 shows, this PADD's refining market remained unconcentrated at the end of the decade. According to EIA's data, as of 2001, the quantity of gasoline refined in PADD II was slightly less than the quantity consumed within the PADD.

Figure 3: Refining Market Concentration for PADD II Based on Crude Oil Distillation Capacity (1990-2000)

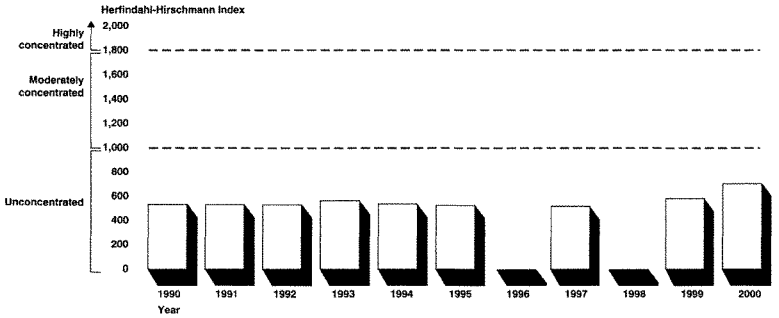


Source: GAO analysis of EIA data.

Note: Data for 1996 and 1998 were unavailable.

The refining market in PADD III (the Gulf Coast), like PADD II, was unconcentrated as of the end of 2000, although its HHI increased by 170—from 534 in 1990 to 704 in 2000 (see fig. 4). According to EIA's data, much more gasoline is refined in PADD III than is consumed within the PADD, making PADD III the largest net exporter of gasoline to other parts of the United States.

Figure 4: Refining Market Concentration for PADD III Based on Crude Oil Distillation Capacity (1990-2000)

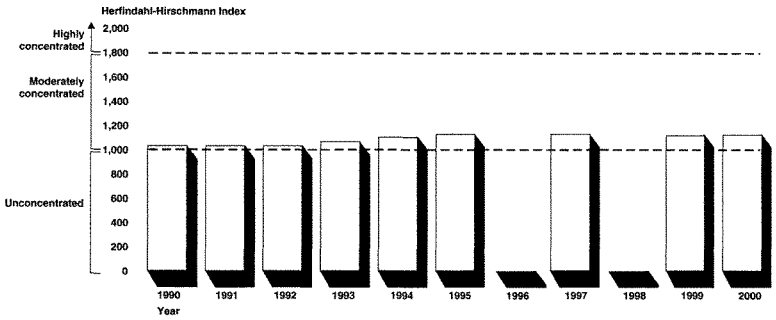


Source: GAO analysis of EIA data.

Note: Data for 1996 and 1998 were unavailable.

The HHI for the refining market in PADD IV—the Rocky Mountain region—where gasoline production and consumption are almost balanced—increased by 95 between 1990 and 2000. This increase changed the PADD's refining market from 1029 in 1990 to 1124 in 2000, within the moderate level of market concentration (see fig. 5).

Figure 5: Refining Market Concentration for PADD IV Based on Crude Oil Distillation Capacity (1990-2000)



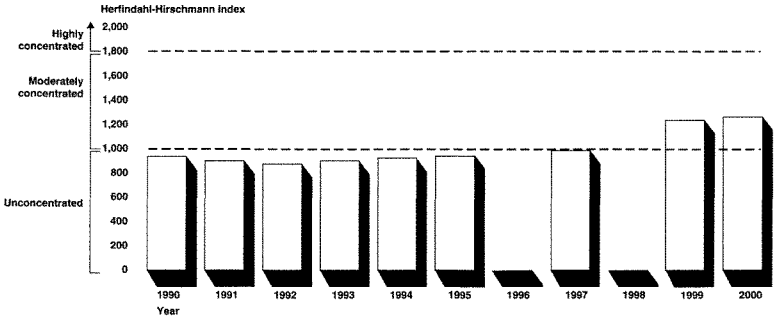
Source: GAO analysis of EIA data.

Note: Data for 1996 and 1998 were unavailable.

The refining market's HHI for PADD V—the West Coast—increased from 937 to 1267, an increase of 330, between 1990 and 2000 and changed the West Coast refining market, which produces most of the gasoline it consumes, from unconcentrated to moderately concentrated by the end of the decade (see fig. 6).[7]

[7]Some industry officials and experts believe that the California refining market, which is a part of PADD V, is more concentrated than the PADD as a whole because a unique (CARB) gasoline consumed in the state and the production of the gasoline is dominated by a few large refiners.

Figure 6: Refining Market Concentration for PADD V Based on Crude Oil Distillation Capacity (1990-2000)



Source: GAO analysis of EIA data.

Note: Data for 1996 and 1998 were unavailable.

We estimated a high and statistically significant degree of correlation between merger activity and the HHIs for refining in PADDs I, II, and V for 1991 through 2000. Specifically, the corresponding correlation numbers are 91 percent for PADD V (West Coast), 93 percent for PADD II (Midwest), and 80 percent for PADD I (East Coast). While mergers were positively correlated with refining HHIs in PADDs III and IV—the Gulf Coast and the Rocky Mountains—the estimated correlations were not statistically significant.

In wholesale gasoline markets, market concentration increased broadly throughout the United States between 1994 and 2002. Specifically, we found that 46 states and the District of Columbia had moderately or highly concentrated markets by 2002, compared to 27 in 1994.

Evidence from various sources indicates that, in addition to increasing market concentration, mergers also contributed to changes in other aspects of market structure in the U.S. petroleum industry that affect competition—specifically, vertical integration and barriers to entry.

However, we could not quantify the extent of these changes because of a lack of relevant data.

Vertical integration can conceptually have both pro- and anticompetitive effects. Based on anecdotal evidence and economic analyses by some industry experts, we determined that a number of mergers that have occurred since the 1990s have led to greater vertical integration in the U.S. petroleum industry, especially in the refining and marketing segment. For example, we identified eight mergers that occurred between 1995 and 2001 that might have enhanced the degree of vertical integration, particularly in the downstream segment.

Concerning barriers to entry, our interviews with petroleum industry officials and experts provide evidence that mergers had some impact on the U.S. petroleum industry. Barriers to entry could have implications for market competition because companies that operate in concentrated industries with high barriers to entry are more likely to possess market power. Industry officials pointed out that large capital requirements and environmental regulations constitute barriers for potential new entrants into the U.S. refining business. For example, the officials indicated that a typical refinery could cost billions of dollars to build and that it may be difficult to obtain the necessary permits from the relevant state or local authorities.

U.S. Gasoline Marketing Has Changed in Two Major Ways

According to some petroleum industry officials that we interviewed, gasoline marketing in the United States has changed in two major ways since the 1990s. First, the availability of unbranded gasoline has decreased, partly due to mergers. Officials noted that unbranded gasoline is generally priced lower than branded. They generally attributed the decreased availability of unbranded gasoline to one or more of the following factors:

- There are now fewer independent refiners, who typically supply mostly unbranded gasoline. These refiners have been acquired by branded companies, have grown large enough to be considered a brand, or have simply closed down.
- Partially or fully vertically integrated oil companies have sold or mothballed some refineries. As a result, some of these companies now have only enough refinery capacity to supply their own branded needs, with little or no excess to sell as unbranded.

- Major branded refiners are managing their inventory more efficiently, ensuring that they produce only enough gasoline to meet their current branded needs. We could not quantify the extent of the decrease in the unbranded gasoline supply because the data required for such analyses do not exist.

The second change identified by these officials is that refiners now prefer dealing with large distributors and retailers because they present a lower credit risk and because it is more efficient to sell a larger volume through fewer entities. Refiners manifest this preference by setting minimum volume requirements for gasoline purchases. These requirements have motivated further consolidation in the distributor and retail sectors, including the rise of hypermarkets.

Mergers and Increased Market Concentration Generally Led to Higher U.S. Wholesale Gasoline Prices

Our econometric modeling shows that the mergers we examined mostly led to higher wholesale gasoline prices in the second half of the 1990s. The majority of the eight specific mergers we examined—Ultramar Diamond Shamrock (UDS)-Total, Tosco-Unocal, Marathon-Ashland, Shell-Texaco I (Equilon), Shell-Texaco II (Motiva), BP-Amoco, Exxon-Mobil, and Marathon Ashland Petroleum (MAP)-UDS—resulted in higher prices of wholesale gasoline in the cities where the merging companies supplied gasoline before they merged. The effects of some of the mergers were inconclusive, especially for boutique fuels sold in the East Coast and Gulf Coast regions and in California.

- For the seven mergers that we modeled for conventional gasoline, five led to increased prices, especially the MAP-UDS and Exxon-Mobil mergers, where the increases generally exceeded 2 cents per gallon, on average.
- For the four mergers that we modeled for reformulated gasoline, two—Exxon-Mobil and Marathon-Ashland—led to increased prices of about 1 cent per gallon, on average. In contrast, the Shell-Texaco II (Motiva) merger led to price decreases of less than one-half cent per gallon, on average, for branded gasoline only.
- For the two mergers—Tosco-Unocal and Shell-Texaco I (Equilon)—that we modeled for gasoline used in California, known as California Air Resources Board (CARB) gasoline, only the Tosco-Unocal merger led to price increases. The increases were for branded gasoline only and exceeded 6 cents per gallon, on average.

For market concentration, which captures the cumulative effects of mergers as well as other competitive factors, our econometric analysis shows that increased market concentration resulted in higher wholesale gasoline prices.

- Prices for conventional (non-boutique) gasoline, the dominant type of gasoline sold nationwide from 1994 through 2000, increased by less than one-half cent per gallon, on average, for branded and unbranded gasoline. The increases were larger in the West than in the East—the increases were between one-half cent and one cent per gallon in the West, and about one-quarter cent in the East (for branded gasoline only), on average.

- Price increases for boutique fuels sold in some parts of the East Coast and Gulf Coast regions and in California were larger compared to the increases for conventional gasoline. The wholesale prices increased by an average of about 1 cent per gallon for boutique fuel sold in the East Coast and Gulf Coast regions between 1995 and 2000, and by an average of over 7 cents per gallon in California between 1996 and 2000.

Our analysis shows that wholesale gasoline prices were also affected by other factors included in the econometric models, including gasoline inventories relative to demand, supply disruptions in some parts of the Midwest and the West Coast, and refinery capacity utilization rates. For refinery capacity utilization rates, we found that prices were higher by about an average of one-tenth to two-tenths of 1 cent per gallon when utilization rates increased by 1 percent. We found that prices were higher because higher refinery capacity utilization rates leave little room for error in predicting short-run demand. During the period of our study, refinery capacity utilization rates at the national level averaged about 94 percent per week.

Mr. Chairman, this concludes my prepared statement. I would be happy to respond to any questions that you or other Members of the Subcommittee may have.

GAO Contacts and Staff Acknowledgments

For further information about this testimony, please contact me at (202) 512-3841. Key contributors to this testimony included Godwin Agbara, John A. Karikari, and Cynthia Norris.

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

Janet Napolitano
Governor

1110 West Washington Street· Phoenix, Arizona 85007
(602) 771-2300 · www.adeq.state.az.us

Stephen A. Owens
Director

VIA FEDERAL EXPRESS

AQD:CTS:94383

July 29, 2004

Jeff Donofrio
Committee on Energy and Commerce Democratic Staff
U.S. House of Representatives
2322 RHOB
Washington, D.C. 20515

Subject: Chronology and History of the Proposed Arizona Clean Fuels Refinery

Dear Mr. Donofrio:

As was promised in a July 21, 2004, conference call with you and your colleagues, I have enclosed with this letter a chronological summary of the documents that relate to the Arizona Department of Environmental Quality's efforts to process air quality applications for a proposed new refinery to be constructed and operated by Arizona Clean Fuels. In addition to the chronological summary, I have also enclosed copies of the documents used to develop this summary.

I hope that this information provides you with the history associated with this proposed project, and should you need any additional information, please contact me at (602) 771-2308.

Sincerely,

Nancy C. Wrona, Director
Air Quality Division

NCW:ecm

Enclosures

Chronology of Documents for
Arizona Clean Fuels (a.k.a. Maricopa Refining Company)

Document Title	Issuance Date
Air Quality Installation Permit Number 1228 Synopsis: Permit issued to Maricopa Refining Co. (a.k.a. Arizona Clean Fuels) allowing construction and installation of equipment.	**January 16, 1992**
Class I Permit Application Cover Letter Synopsis: Cover letter from Dames and Moore (now URS Corporation, a.k.a. URS), Arizona Clean Fuels' contractor, applying for a new air quality installation and operating permit.	**December 23, 1999**
Permit Application Incompleteness Letter Synopsis: Letter from Arizona Department of Environmental Quality (ADEQ) to Arizona Clean Fuels requesting additional information in support of the December 23, 1999, permit application.	**January 31, 2000**
Memorandum Regarding Preliminary BACT Review Synopsis: Comments from RTP Environmental Associates (RTP), ADEQ's contractor, to ADEQ, Arizona Clean Fuels and URS regarding the Best Available Control Technology (BACT) review performed in the December 23, 1999, permit application.	**March 17, 2000**
Revised Sections of Permit Application Cover Letter Synopsis: Letter from URS to Arizona Clean Fuels and ADEQ responding to some of the comments in RTP's March 17, 2000, memorandum.	**June 29, 2001**
Memorandum Regarding Preliminary BACT Review Synopsis: Additional comments from RTP to ADEQ, Arizona Clean Fuels, and URS responding to URS's June 29, 2001, submittal.	**August 2, 2001**
Permit Application Addendum Cover Letter Synopsis: Cover letter for a new application addendum submitted by URS, containing some responses to RTP's August 2, 2001, comments, as well as some information requested in ADEQ's January 31, 2000, incompleteness letter.	**October 31, 2001**
Permit Application Addendum Cover Letter Synopsis: Cover letter for a new application addendum submitted by URS, containing additional responses to RTP's August 2, 2001, request for information.	**November 16, 2001**

Chronology of Documents for
Arizona Clean Fuels (a.k.a. Maricopa Refining Company)

Document Title	Issuance Date
Permit Application Addendum Cover Letter Synopsis: Cover letter for a new application addendum submitted by URS, containing additional responses to RTP's comments, as well as some information requested in ADEQ's January 31, 2000, incompleteness letter.	**March 14, 2002**
Response to Comments Letter Synopsis: Letter from URS to RTP supplementing the October 2001, November 2001 and March 2002 permit application addendums.	**April 24, 2002**
Permit Application Completeness Letter Synopsis: Letter from ADEQ to Arizona Clean Fuels, indicating that, based on all the information received on or before August 23, 2002, the application was deemed complete.	**September 4, 2002**
Letter Regarding Predicted Impacts on Nearby Community Synopsis: Letter from Gallagher and Kennedy, Arizona Clean Fuels' attorneys, explaining the company's willingness to relocate a local school and community center in order to minimize predicted impacts on the nearby community.	**September 5, 2003**
Letter Regarding Relocation of Proposed Refinery Synopsis: Letter from Gallagher and Kennedy to ADEQ explaining Arizona Clean Fuels intent to relocate the proposed project to Yuma, Arizona, and that a new, site-specific permit application would be resubmitted in the future.	**October 30, 2003**
Letters Regarding Licensing Time Frames Synopsis: Letters between ADEQ, Arizona Clean Fuels, Office of the Attorney General, and Gallagher and Kennedy, agreeing to restart the permitting timeframes upon receipt of a new permit application.	**April 5-6, 2004**
New Application Cover Letter Synopsis: Cover letter from URS Corporation on behalf of Arizona Clean Fuels, submitting a new application for an air quality installation and operating permit.	**July 14, 2004**

057083

DAMES & MOORE

A DAMES & MOORE GROUP COMPANY

7500 North Dreamy Draw Drive
Suite 145
Phoenix, Arizona 85020
602 371 1110 Tel
602 861 7431 Fax

December 23, 1999

Mr. Prabhat Bhargava, P.E.
Permits Section Manager
Air Quality Division
Arizona Department of Environmental Quality
3003 North Central Avenue
Phoenix, Arizona 85012-2905

Re: Class I Permit Application – Arizona Clean Fuels, LLC
D&M Job No. 30530-002-131

Dear Mr. Bhargava:

On behalf of Arizona Clean Fuels, LLC, (ACF) we submit herein a Class I/Prevention of Significant Deterioration Permit Application for the ACF refinery project. This application is submitted in accordance with the requirements of Arizona Administrative Code R18-2-402 and R18-2-406. As we have discussed, these documents do not contain the complete air impact analysis required for new major sources. That portion of the application is in progress and will be submitted by ACF under separate cover.

Copies of this application have been forwarded to appropriate individuals at RTP Environmental Associates, Inc., the U.S. Forest Service, the National Park Services, and U.S. EPA Region IX.

Thank you for your attention to this matter. We look forward to working with you and your staff through the permitting process.

Sincerely,
DAMES & MOORE

Robert T. Estes
Manager, Air Quality Services
Southwest Region

Robert W. Farmer, Ph.D., P.E.
Senior Chemical Engineer
Air Quality Services

Encl - Class I / PSD Permit Application – 2 Volumes

cc: J. Greenbank, ACF
J. Adams, ACF
D. Lucchese, ADEQ
C. Campbell, RTP Assoc
R. Graw, RTP Assoc.
P. Lahm, USFS
T. Maniero, NPS
S. Bohning, U.S. EPA Region IX
J.S. Curry, Gallagher & Kennedy
T. Carr, D&M

ADQ:PS23309

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

Governor Jane Dee Hull Jacqueline E. Schafer, Director

January 31, 2000

CERTIFIED MAIL
RETURN RECEIPT

Mr. John Greenbank, CEO
Arizona Clean Fuels, LLC
10201 S. 51st Street, Suite 180
Phoenix, Arizona 85044

Subject: Air Quality Permit Application - Permit #1001205 - Incomplete Letter

Dear Mr. Greenbank:

This letter is in regard to your air quality permit application dated December 22, 1999 and received on December 23, 1999 for a petroleum refinery in Maricopa County, Arizona.

After initial review, this division has determined that the application is incomplete. The following is a list of items which need to be addressed before the application can be deemed complete:

1. SIP Requirements. The application submittal does not identify applicable and non-applicable SIP requirements. Section 5.4 of the application states that SIP rule applicability is summarized in Table 5.10, but Table 5.10 presents information pertaining to 40 CFR part 63 subpart CC.
2. Impacts Analyses. The application submittal does not include analyses of air quality impacts as required by Arizona Administrative Code (A.A.C.) R18-2-407.

According to A.A.C. R18-2-304.G, you have a duty to supplement or correct this application upon becoming aware of any omission or error contained in it. You also are required to provide additional information as necessary to address any new requirements which become applicable after submittal of this application.

If you have any questions, please do not hesitate to contact me at (602) 207-2329.

Sincerely,

for PRABHAT BHARGAVA

Prabhat Bhargava, Manager
Permits Section, Air Quality Division

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
OFFICE OF AIR QUALITY
2005 N. Central Avenue - Phoenix, AZ 85004 - Phone: (602) 257-2283

INSTALLATION PERMIT

(As required by Title 49, Chapter 3, Article 2, Section 49-426, Arizona Revised Statutes and Chapter 2, Article 3, Arizona Administrative Code)

1. PERMIT TO BE ISSUED TO (Business license name of organization that is to receive permit) Maricopa Refining Co.

2. NAME (OR NAMES) OF OWNER OR PRINCIPALS DOING BUSINESS AS THE ABOVE ORGANIZATION John A. Greenbank

3. MAILING ADDRESS 5333 N. 7th Street, Suite 125 (NUMBER, STREET)
Phoenix (CITY OR COMMUNITY) AZ (STATE) 85014 (ZIP CODE)

4. EQUIPMENT LOCATION ADDRESS 9400 W. State Route 238 (NUMBER, STREET)
Mobile (CITY OR COMMUNITY) AZ (STATE) (ZIP CODE)

5. FACILITIES OR EQUIPMENT DESCRIPTION Atmospheric crude unit, vacuum unit, catalytic reformer, hydrodesulfurizer units and sulfur plant. This is a 50,000 barrel per day crude oil refinery.

6. THIS PERMIT ISSUED SUBJECT TO THE FOLLOWING conditions contained in Attachments A, B and C.

7. ADEQ PERMIT NUMBER 1228 PERMIT CLASS A

PERMIT ISSUED THIS 16th DAY OF January, 19 92.

SIGNATURE — TITLE: Assistant Director

The issuance of this permit shall in no way be construed as a warranty affirmation or indication that the equipment described herein will qualify for an operating permit. It is the sole responsibility of the applicant to comply with all applicable air pollution laws, regulations and standards.

ADEQ/OAQ/P100C (7-87)

ATTACHMENT "A"

General Provisions

Installation Permit No. 1228

for MARICOPA REFINING COMPANY

I. Permit Expiration

This Installation Permit shall be canceled (1) if construction is not commenced (as defined in A.A.C. R18-2-101.23) within 18 months after the date of issuance of the permit, (2) if construction is discontinued for a period of 18 months or more, or (3) if construction is not completed within five years of the date of issuance of the permit.

II. Notification of Commencement of Construction and Startup

The Department shall be notified in writing of the anticipated date of initial start-up (as defined in A.A.C. R18-2-101.92) of each facility of the source not more than sixty (60) days nor less than thirty (30) days prior to such date and shall be notified in writing of the actual date of commencement of construction and start-up within fifteen (15) days after such date.

III. Facilities Operation

All equipment, facilities, and systems installed or used to achieve compliance with the terms and conditions of this Installation Permit shall at all times be maintained in good working order and be operated as efficiently as practicable so as to minimize air pollutant emissions.

IV. Malfunction

The Department shall be notified by telephone within 48 hours following any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner which results in an increase in emissions above any allowable emissions limit stated in Attachment "B" and "C" of these conditions. In addition, the Department shall be notified in writing within fifteen (15) working days of any such failure. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial failure, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed under Attachment "B" and "C" of these conditions, and the methods utilized to restore normal operations. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violations of this permit, any statute, rule or regulations which such malfunction may cause except as provided in A.A.C. R18-2-309.

V. Right to Entry

The authorized representatives of the Department, upon the presentation of credentials, shall be permitted at reasonable times:

A. to enter upon the premises where the source is located or in which any records are required to be kept under the terms and conditions of this Installation Permit; and

B. to have access to and copy any records required to be kept under the terms and conditions of this Installation Permit; and

C. to inspect any equipment, operation, or method required in this Installation Permit; and

D. to sample emissions from the source.

VI. Transfer of Ownership

This Installation Permit is non-transferable whether by operation of law or otherwise, either from one location to another, from one piece of equipment to another, or from one person to another. The applicant shall notify the succeeding owner and operator of the existence of this Installation Permit and its conditions and need to obtain a new permit from the Department by letter, a copy of which shall be forwarded to the Department.

VII. Severability

The provisions of this Installation Permit are severable, and, if any provision of this Installation Permit is held invalid, the remainder of this Installation Permit shall not be affected thereby.

VIII. Other Applicable Regulations

The owner and operator of the proposed project shall construct and operate the proposed stationary source in compliance with all other applicable provisions of A.A.C. Title 18, Chapter 2 and all other applicable Federal regulations.

IX. Representations in Application for Permit and Exemption.

All representations with regard to construction plans and operation procedures in the application for a Installation permit become conditions upon which a subsequent Installation Permits, Operating Permits are issued. Any variance from such representation if the change will cause a change in the method of control of emissions, the character of the emissions, or will result in an increase in the discharge of the various emissions, will be considered violation of this permit unless permittee first makes application to the Department in that regard and such amendment or new installation permit is approved by the Department.

X. Allowable Emissions

Permittee is authorized to discharge or cause to discharge into atmosphere emissions of air contaminants from only those facilities that are listed in the Attachment "C", unless otherwise such emissions are authorized under separate Installation or Operating Permit.

XI. Operation of the Equipment

This permit authorizes the temporary operation of the proposed facility for a period of ninety days following installation. All tests, analyses or gathering of information necessary to comply with the installation permit or to qualify for an operating permit shall be gathered during the ninety-day period.

ATTACHMENT B
Special Conditions

MARICOPA REFINING COMPANY (MRC)

I. Applicable Rules

The Maricopa Refining Company (MRC) shall construct and operate the Maricopa Oil Refinery in compliance with the following rules and regulations for air pollution control:

A.A.C., R18-2-302: Installation permits, general.

A.A.C., R18-2-304: Installation permit requirements for sources located in attainment and unclassifiable areas.

A.A.C., R18-2-801: Standards of performance for new stationary sources.

A.A.C., R18-2-801.1. Subpart A: General Provisions

A.A.C., R18-2-801.10 Subpart J: Petroleum Refineries

A.A.C., R18-2-801.13 Subpart Kb: Volatile Organic liquid Storage Vessels (including petroleum liquid).

A.A.C., R18-2-801.53 Subpart GGG: Equipment Leaks of VOC in Petroleum Refineries.

40 CFR Part 60, Subpart QQQ: Standards of performance for VOC Emissions from Petroleum Refinery Wastewater Systems.

All other applicable federal and local rules and regulations for air pollution control.

II. Emission Limits

A. On and after the date of startup of the Maricopa Oil Refinery, MRC shall not discharge or cause the discharge into the atmosphere, from the emission points listed, pollutants in excess of the limits specified in Attachment C.

B. On and after the date of startup, MRC shall not cause to be discharged into the atmosphere from the above-listed emission points any gases which exhibit greater than twenty percent (20%) opacity.

C. In addition to the above, excess emissions shall be defined as:

1. Any consecutive three-hour period during which the average concentration of H_2S in any fuel gas combusted in any fuel gas combustion device exceeds 23 mg/dscm (0.01 gr/dscf).

2. Any consecutive three-hour period during which the average hourly emissions of NO_x from Emission Control System (ECS) Numbers One, Two, or Three, or the Reformer unit heater exceed 30 ppmv; or from the Sulfur Receovery Unit (SRU), 120 ppmv.

Excess emissions indicated by the CEM system shall be considered violations of the applicable emission limit for the purposes of this permit.

III. Stack Sampling Facilities

For performance test purposes, sampling ports, platforms, and access shall be provided by the MRC on the emission points identified as ECS-1, ECS-2, ECS-3, the reformer heater, and the SRU, in accordance with Arizona Testing Manual for Air Pollutant Emissions.

IV. Performance Tests

A. Within sixty days after achieving the maximum production rate of the Maricopa refinery, but not later than one hundred eighty days after initial startup (as defined in A.A.C. R18-2-312) of the Maricopa Refinery, the MRC shall conduct or cause to be conducted performance tests (as required by R18-2-312) on the emission points identified as ECS-1, ECS-2, ECS-3, the reformer heater, and the SRU. Performance tests shall be conducted for PM-10, SO_2, NO_x, and VOC. The MRC shall furnish the Department a written report of such tests. All performance tests shall be conducted at the maximum operating capacity of the unit being tested; however,upon receipt of prior written approval from the Department, the MRC may conduct performance tests at less than the maximum operating capacity of the units being tested.

Performance tests on the Maricopa Refinery shall be conducted on at least an annual basis and at such other times as may be specified by the Department.

B. Performance tests for the emissions of PM-10, SO_2, NO_x, and VOC shall be conducted and results reported in accordance with the test methods set forth in the Arizona Testing Manual for Air Pollution Emissions. The following test methods shall be used:
Performance tests for the emission of PM-10 shall be conducted using USEPA Method 201 or 201A; for SO_2, Method 8; for NO_x, Method 7; and for VOC, Method 18; as modified by the Arizona Testing manual for Air Pollution Emissions.

A pre-test meeting shall be arranged with the Department at least fourteen calendar days prior to such tests to allow time for the development of an approvable performance test plan and to arrange for an observer to be present at the test. The MRC shall prepare and submit a written copy of the proposed test plan to the Department seven calendar days prior to pre-test meeting. A written copy of the Final Test Plan must be submitted to the Department prior to performance tests. Such prior approval will minimize the possibility of the Department's rejection of the test results for procedural deficiencies. in lieu of the above-mentioned test methods, equivalent methods may be used with prior approval from the Department.

V. Continuous Emissions Monitoring (CEM)

A. Prior to the date of startup and thereafter, the MRC shall install, maintain and operate the following continuous monitoring systems for emission points identified as ECS-1, ECS-2, ECS-3, the reformer heater, and the SRU.

1. Continuous monitoring system to measure stack gas NO_x concentrations. The system shall meet monitoring performance specifications specified in 40 CFR 60 Appendix B, or as might be modified by the Arizona Testing Manual for Air Pollutant Emissions.

2. Continuous monitoring system to measure fuel gas H_2S concentration. The system shall meet monitoring performance specifications specified in 40 CRF 60.105 (a)(4), or as might be modified by the Arizona Testing Manual for Air Pollutant Emissions.

3. Continuous monitoring system to measure fuel gas volumetric flow rates. The system shall meet monitoring performance specifications specified in the Arizona Testing Manual for Air Pollutant Emissions.

4. In addition, for the Sulfur Recovery Unit, continuous monitoring system to measure stack gas SO_2 concentration. The system shall meet the specifications of 40 CFR 60 Appendix B.

B. The MRC shall notify the Department of the date upon which demonstration of the continuous monitoring systems performance commences.

C. The MRC shall submit written reports of all excess emissions to the Department for every three-month period ending on March 31, June 30, September 30, and December 31. The report shall include the following:

1. The magnitude of excess emissions computed in accordance with the Arizona Testing Manual for Air Pollutant Emissions, any conversion factor(s) used, and the date and time of commencement and completion of each time period of excess emissions.

2. Specific identification of each period of excess emissions that occurs during startups, shutdowns, and malfunctions of any of the process heaters. The nature and cause of any malfunction (if known) and the corrective action taken or preventative measures adopted shall also be reported.

3. The date and time identifying each period during which the continuous monitoring system was inoperative except for zero and span checks and the nature of the system repairs or adjustment.

4. When no excess emissions have occurred or the continuous monitoring system has been inoperative, repaired, or adjusted, such information shall be stated in the report.

D. Quality Assurance for CEM's

Not less than thirty days prior to the date of startup of the Maricopa Refinery, the MRC shall submit to the Department a quality assurance project plan for the certification and operation of the continuous emission monitors. No operating Permit shall be issued until a Continuous Emission Monitoring quality assurance project plan has been approved by the Department.

Within sixty days after achieving the maximum production rate of the Maricopa Refinery, but no later than one hundred eighty days after initial startup (as defined in A.A.C. R18-2-101.92) of the Maricopa Refinery, the MRC shall conduct or cause to be conducted certification of Continuous Emission Monitors of the Maricopa Refinery. Certification tests shall be conducted for all continuous emission monitors required using methods specified in the applicable New Source performance Standards, 40 CFR 60 Appendix F, or as might be modified by the Arizona Testing Manual for Air Pollutant Emissions. The MRC shall furnish the Department a written report of such tests.

E. The MRC shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by the New Source Performance Standards for petroleum refineries and equipment leaks of VOC in petroleum refineries, recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports and records.

VI. Fuel Type

The MRC is permitted to burn only treated refinery gas and/or natural gas in the process heaters.

VII. Refinery Crude Oil Feedstock

The crude oil feedstock going into the Crude Unit, which is the first processing unit, shall not contain more than 2% sulfur. The permanent feedstock sulfur content limit

may be increased after the plant is started if (1) MRC can demonstrate by calculation from actual plant performance that the higher content crude oil will not violate emissions in Attachment C, (2) the Department is notified 30 days prior to a feedstock change and (3) the Department approves the feedstock change. If there are no crude oil feedstocks on the MRC property that exceed the permanent feedstock sulfur limit, then MRC may use the batch or lot crude oil analysis for showing compliance with this section. If there are out-of-limit feedstocks to be blended on the plant property so as to comply with the sulfur feedstock limit, then MRC must demonstrate by sampling and analysis that the feedstock entering the first crude oil processing unit meets the sulfur feed limit. This demonstration will continue until MRC can demonstrate that all feedstocks on the property are below the maximum sulfur content. The feedstock analysis and demonstration requirements shall be maintained at MRC for a two year period and shall be available for periodic inspection by the Department.

VIII. Fuel Amount and Record Keeping

The total amount of treated refinery gas and natural gas consumed in the Maricopa Refinery shall not exceed 0.32 million SCF/hour on a daily average and shall not exceed $2.8X10^9$ SCF during any calendar year. The MRC shall construct the Maricopa Refinery with the equipment necessary, and maintain such records as required, to document the above fuel use.

IX. Fuel Analysis

The sulfur content of the treated refinery gas and natural gas burned in the Maricopa Refinery shall not exceed 23 mg/dscm (0.01 gr/dscf) of hydrogen sulfide.

The amount of fuel burned and the sulfur content of the fuel burned shall be recorded in a permanent record and shall be available for periodic inspection by the Department.

X. Air Pollution Equipment

The MRC shall install, continuously operate and maintain the following air pollution controls. Controls listed shall be fully operational upon startup of the respective sources.

Wet-scrubbing systems shall be used to remove NO_x from each of the process heater stacks. These are grouped into the three emission control systems:

ECS-1 for Crude Heater (H-101)
Vacuum Heater (H-102)
Visbreaker Heater (H-401)

ECS-2 for Naptha HDS Heater (H-201)
Distillate HDS Heater (H-701)

ECS-3 for Hot Oil Belt Heater (H-801)
Boilers (H-802)

and the Reformer Unit Heater (H-301, H-302 and H303).

These NO_x scrubbers will operate with at least 90% removal efficiency.

XI. Storage and Loading of Petroleum Fluids

A. The four gasoline storage tanks (each 20,000 BBL capacity) shall be equipped with internal floating roofs with a primary resilient foam log seal and a secondary rim-mounted seal.

B. The five crude oil storage tanks (each 150,000 BBL capacity) shall be equipped with external floating roofs with a primary metallic shoe seal and a secondary flexible wiper seal.

C. The storage of all other petroleum liquids (all with true maximum vapor pressures less than 0.2 kPa) will be in fixed-roof tanks.

D. Truck and rail car loading racks used for gasoline, diesel and jet fuels shall incorporate bottom loading with vapor discharge to the vapor recovery system. The vapor recovery system shall comply with 40 CFR 60.482-10, including VOC recovery efficiency of at least 95%. Performance tests on the loading racks shall follow the appropriate provisions of Section IV above, and shall utilize the methodology prescribed in California Air Resources Board Methods 2-3 and 2-4.

E. For purposes of assuring compliance with VOC emission limitations, the permittee shall maintain a monthly emissions record which describes calculated emissions (using methodology prescribed in AP-42, Section 4.3) of VOC from all storage tanks and loading operations. The record shall include tank or loading point identification number, control method used, tank or vessel capacity in gallons, name of the material stored or loaded, VOC molecular weight, VOC monthly average temperature in

degrees Fahrenheit, VOC vapor pressure at the monthly average material temperature in psia, VOC throughput for the previous month and year-to-date in gallons and total tons of emissions including controls for the previous month and year-to-date. This record shall be maintained at the plant site for at least two years and be made available to representatives of ADEQ upon request.

F. The emergency flare shall be used for emergency operations or upsets only. Any instances of such operation of the flare shall be reported to the Department in the quarterly reports called for in Section V.C. The flare shall be designed in accordance with 40 CFR 60.18.

ATTACHMENT C

EMISSION SOURCES AND MAXIMUM ALLOWABLE EMISSION RATES FOR THE MARICOPA REFINERY, MOBILE, ARIZONA

This table lists all sources of air contaminants on applicant's property emitted by the facility covered in this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

AIR CONTAMINANT DATA - EMISSION RATES*													
EMISSION POINT ID	SOURCE NAME	VOC (3)		NOx (4)		SO2 (5)		PM-10 (6)		CO (7)		BENZENE (7)	
(1)	(2)	#/HR	T/YR	#/HR	T/YR	#/HR	T/YR	#/HR	T/YR	#/HR	T/YR	#/HR	T/YR
1	Emission Control System #1	3.6986	15.3	1.3470	5.6	0.2511	1.04	0.2489	1.03	3.6986	15.3	0.0	0.0
2	Emission Control System #2	1.7352	7.2	0.6393	2.6	0.1142	0.47	0.1187	0.49	1.7352	7.2	0.0	0.0
3	Emission Control System #3	4.8858	20.2	1.7808	7.4	0.3425	1.42	0.3288	1.37	4.8858	20.2	0.0	0.0
4	Reformer Heater	2.5571	10.6	0.9361	3.9	0.1826	0.76	0.1712	0.71	2.5571	10.6	0.0	0.0
5	Sulfur Recovery Plant (Claus)	0.2511	1.0	4.5089	18.7	7.4879	31	0.0171	0.07	0.2511	1.0	0.0	0.0
6	Crude Oil Tanks	1.4655	6.067	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0021	0.008
7	No.6 Oil & Asphalt Tanks	0.0539	0.223	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8	Heavy Gas & Oil Tanks	0.0162	0.067	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9	Diesel Tanks	0.7085	2.933	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0006	0.002
10	Gasoline Tanks	2.0128	8.33	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0408	0.169
11	Kerosine Tanks	1.2464	5.16	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0019	0.008
12	Loading Racks	4.7260	20.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0715	0.30
13	Fugitives	17.7054	77.5	0.0	0.0	0.0	0.0	1.6667	7.3	0.0	0.0	0.06	0.25
14	Fire Water Pump (15 minutes/week)	1.4802	0.0096	18.502	0.1203	1.2304	0.008	1.2304	0.008	4.004	0.026	0.0	0.0
15	API Separator	0.4726	2.07	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0007	0.0029
16	Cooling Towers	0.0904	0.3745	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0008	0.00311
ALL	TOTALS FROM ALL SOURCES	43.11	177.73	27.71	38.32	9.61	34.70	3.78	10.98	17.13	54.33	0.18	0.74

* An explanation of terms is found on the next page.

ATTACHMENT C (CONTINUED)

EMISSION SOURCES AND MAXIMUM ALLOWABLE EMISSION RATES FOR THE MARICOPA REFINERY, MOBILE, ARIZONA

Terms found on the preceding page are as follows:

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) Volatile Organic Compounds as defined in A.C.C. R18-2-101.170.
(4) Total oxides of nitrogen
(5) Sulfur Dioxide.
(6) Particulate matter of 10 microns or less diameter.
(7) Other contaminants not listed; should be specific.

*Emission rates are based on the following operating schedule:

Source numbers 6,7,8,9,10,11,12,&13:	Hours/day = 24	Days/week = 7	Weeks/year = 52	Hours/year = 8760
Source numbers 1,2,3,4,5,15,&16:	Hours/day = 24	Days/week = 7	Weeks/year = 50-51	Hours/year = 8280-8520
Source number 14:	Hours/day = 1/4	Days/week = 1	Weeks/year = 52	Hours/year = 13

Emission Control System #1 includes:
Crude Unit
Vacuum Unit
Visbreaker Unit

Emission Control System #2 includes:
Naphtha Hydrodesulfurizer Unit
Distillate Hydrodesulfurizer Unit

Emission Control System #3 includes:
Hot Oil Belt Heater
Boilers

304-A West Millbrook Road
Raleigh NC 27609
Phone: (919) 845-1422
Fax: (919) 845-1424
e-mail: campbell@rtpenv.com

RTP Environmental Associates, Inc.

Memo

To: Don Butler, ADEQ Task Assignment Manager

From: Colin Campbell

Date: March 17, 2000

CC: John Greenbank, Arizona Clean Fuels LLC
Bob Farmer, ENSR
Akhilesh Misra, ADEQ Project Manager
Rick Rivera, ADEQ Contract Officer

Re: Task Assignment 98-0022AC-02 – Preliminary BACT Review

We have completed a brief and preliminary review of the BACT analysis presented in the Arizona Clean Fuels LLC PSD permit application dated December 22, 1999. This memo presents outstanding issues resulting from that review:

Refinery fuel gas-fired combustion units

General

- The BACT analyses appear to be based on the assumption that all fired heaters fire refinery fuel gas at all times. If any technical/economic feasibility determinations rely upon differences between natural gas and refinery fuel gas (e.g., higher sulfur in refinery fuel gas), applicant must demonstrate that limiting some heaters to natural gas is infeasible. Does the permit application specify the quantity of refinery fuel gas available?

NO_x BACT

- $SCONO_x$ was not identified as an available control technology.
- The applicant did not sufficiently demonstrate that SCR is economically infeasible.
    - The detailed cost effectiveness calculations in appendix F to the permit application do not agree with the summarized cost effectiveness values in Table 6.4 of the permit application (e.g., for EPN-01, incremental cost of $4,181/ton in appendix F vs. $9,211/ton in Table 6.4)

- Appendix F shows several units with LNB+SCR having total NO_x removal cost of < $2,000/ton and incremental NO_x removal cost of < $5,000/ton. To my knowledge, ADEQ has not established specific thresholds for NO_x economic feasibility, but in any case these values do not demonstrate economic infeasibility.

- Based on only a preliminary review of available data, we have identified two refineries using SCR for NO_x control on refinery fuel gas-fired combustion units:
  - Chevron Products Co., El Segundo CA – hydrogen reforming furnace equipped with SCR, limited to 5 ppmv NO_x
  - Tosco Refining Co., Wilmington, CA – hydrogen reforming furnace equipped with SCR, limited to 7 ppmv NO_x
  - ADEQ must consider the fact that these refineries are utilizing SCR when evaluating whether SCR is economically infeasible for the applicant's facility
- Even if the applicant makes an adequate demonstration that no add-on controls for NO_x are feasible, the applicant has not sufficiently demonstrated that the proposed NO_x levels (0.05 and 0.09 lb per MMBtu heat input) are the lowest levels achievable with low-NO_x burners or ultra-low-NO_x burners. Based on only a preliminary review of available data, we have identified several refineries with more stringent permit limits for refinery fuel gas-fired process heaters:
  - Tosco Santa Maria, Arroyo Grande, CA – several heaters limited to 0.036 lb NO_x per MMBtu heat input; two boilers equipped with LNB & FGR, limited to 30 ppmv NO_x in boiler exhaust
  - Diamond Shamrock, Three Rivers, TX – several heaters limited to 0.04 lb/MMBtu heat input; one heater limited to 0.045 lb/MMBtu heat input
  - Valero Refining, Corpus Christi, TX – one heater limited to 0.04 lb/MMBtu heat input
- In addition, refineries in two California districts are required to meet refinery-wide average emission limits for existing heaters that are more stringent than the limits proposed by the applicant.
  - Bay Area AQMD Regulation 9, Rule 10, <u>for existing refineries</u>, limits <u>refinery-wide</u> average NO_x emissions from boilers and process heaters to 0.033 lb/MMBtu heat input
  - South Coast AQMD Rule 1109, <u>for existing refineries</u>, requires that 36% of refinery process heaters (heat input basis) meet 0.03 lb/MMBtu heat input limit
  - ADEQ must consider the fact that these regulatory standards exist when evaluating whether the limits proposed by the applicant represent BACT

CO BACT

- $SCONO_x$ was not identified as an available control technology.
- The applicant did not sufficiently demonstrate that the proposed CO level (0.02 lb/MMBtu) is the lowest level achievable with low-NO_x burners or ultra-low-NO_x burners. Based on only a preliminary review of available data, we have identified two refineries with more stringent permit limits for refinery fuel gas-fired process heaters:
    - Chevron Products Co., El Segundo CA – hydrogen reforming furnace equipped with SCR, limited to 25 ppmv CO (~ 0.016 lb/MMBtu heat input)
    - Valero Refining, Corpus Christi, TX – several heaters limited to 0.016 lb/MMBtu heat input

VOC BACT

- The applicant adequately demonstrated that no add-on control is feasible.
- However, the applicant did not sufficiently demonstrate that the proposed VOC level (0.01 lb/MMBtu) is the lowest level achievable. Based on only a preliminary review of available data, we have identified one refinery with a more stringent permit limit for refinery fuel gas-fired process heaters:
    - Koch Refining, Corpus Christi TX – several heaters limited to 1.4 lb VOC per million cubic feet of refinery fuel gas

SO_2 BACT

- The applicant did not evaluate the feasibility of add-on SO_2 control for any fired units.
- Even if the applicant makes an adequate demonstration that no add-on controls for SO_2 emissions are feasible, the applicant has not sufficiently demonstrated that the proposed SO_2 emission level (equivalent to a fuel gas sulfur content of 140 ppmv) represents BACT for refinery fuel-gas fired units.
- Based on only a preliminary review of available data, we have identified several refineries with permit limits for refinery fuel gas sulfur content more stringent than that proposed by the applicant:
    - Diamond Shamrock, Three Rivers, TX – refinery fuel gas limited to 0.03 grains H_2S and 0.07 grains total sulfur (as H_2S) per dscf, annual average basis. The total sulfur limit is approximately equivalent to 112 ppmv.
    - Koch Refining, Corpus Christi, TX – refinery fuel gas limited to 0.06 grains H_2S per dscf, annual average basis.
    - Phillips Petroleum, Sweeny, TX – refinery fuel gas limited to 100 ppmv sulfur as H_2S
    - Tosco Refining Co., Wilmington, CA – refinery fuel gas limited to 100 ppmv sulfur as H_2S

- In addition, refineries in at least one California district are required by rule to meet a refinery fuel gas sulfur limit that is more stringent than the limits proposed by the applicant:
    - South Coast AQMD Rule 431.1 prohibits the burning of refinery fuel gas having a sulfur content in excess of 40 ppmv
    - ADEQ must consider the fact that this regulatory standard exists when evaluating whether the limit proposed by the applicant represents BACT
- The applicant does not appear to have based the emission calculations (in Section 3 of the permit application) on a fuel gas sulfur content of 140 ppmv.

PM/PM-10 BACT

- The applicant adequately demonstrated that no add-on control is feasible.
- However, the applicant did not sufficiently demonstrate that the proposed PM/PM-10 emission limit (0.01 lb per MMBtu heat input) represents BACT for refinery fuel-gas fired units.
- Based on only a preliminary review of available data, we have identified one refinery with PM/PM-10 emission limits for refinery fuel gas-fired combustion units more stringent than that proposed by the applicant:
    - Koch Refining, Corpus Christi TX – one heater limited to 0.0035 lb PM-10 per MMBtu heat input; several heaters limited to 0.005 lb PM per MMBtu heat input.

Sulfur Recovery Unit

- The applicant did not sufficiently demonstrate that the proposed SO_2 emission limit (i.e., 99.8 percent sulfur conversion efficiency in SRU) is BACT. Based on only a preliminary review of available data, we have identified several refineries with higher SRU sulfur conversion efficiencies:
    - BP Amoco, Texas City TX - 99.9% efficiency
    - Citgo Petroleum Corp., Corpus Christi TX – 99.9% efficiency
    - Diamond Shamrock, Three Rivers TX – 99.9% efficiency
    - Exxon Co. USA, Baytown TX – 99.9% efficiency
    - Fina Oil, Port Arthur TX – 99.9% efficiency
    - Koch Refining, Corpus Christi TX – 99.9% efficiency
- The applicant did not present any BACT analysis for the SRU for pollutants other than SO_2. The applicant did provide emission estimates, so we have attempted to compare these estimates to available information that should be identified in the BACT analysis:

- Appendix B to the permit application indicates a sulfur plant feed rate of 376.9 long tons per day (15.7 long tons per hour) and a tail gas incinerator heat input rate of 100 MMBtu/hr
- Appendix B of the application includes a NO_x emission estimate of 6.90 lb/hr NO_x, which is equivalent to 0.069 lb/MMBtu and 0.44 lb/ton
- Based on only a preliminary review of available data, we have identified one refinery with SRU emission limits more stringent than the applicant's emission estimates:
  - Koch Refining, Corpus Christi, TX: 50 ppmv NO_x (equivalent to ~ 0.05 lb/MMBtu) and 10 ppmv H2S in tail gas incinerator exhaust

Process Piping / LDAR

- The applicant did not sufficiently demonstrate that the proposed LDAR program, consistent with 40 CFR part 61 subpart V, is BACT.
- The applicant identified and acknowledged several facilities in the RACT/BACT/LAER Clearinghouse with more stringent programs (i.e., lower leak definitions) than that proposed:
  - CA-0712, all components subject to 100 ppmv leak definition
  - CA-0711, all components subject to 500 ppmv leak definition
  - LA-0085, all components subject to 500 ppmv leak definition
  - CA-0615, valves subject to 500 ppmv leak definition
- Based on only a preliminary review of available data, we have identified several refineries also required to implement more stringent programs than that proposed by the applicant:
  - Clark Refining, Port Arthur, TX – valves and connectors subject to 500 ppmv leak definition, pumps and compressor seals subject to 2000 ppmv leak definition
  - Exxon Company USA, Baytown, TX – valves and connectors subject to 500 ppmv leak definition, pumps and compressor seals subject to 2000 ppmv leak definition
  - Koch Refining, Corpus Christi TX – valves, pumps, compressor seals, connectors subject to 500 ppmv leak definition
  - Marathon Ashland Petroleum, Texas City, TX – valves and connectors subject to 500 ppmv leak definition, pumps and compressor seals subject to 2000 ppmv leak definition

- Motiva Enterprises, Port Arthur, TX – valves, pumps, compressor seals subject to 500 ppmv leak definition
- Seadrift Coke Co., Seadrift, TX – valves, pumps, compressor seals, connectors subject to 500 ppmv leak definition
- Shell Oil, Deer Park, TX – valves, pumps, compressor seals, connectors subject to 500 ppmv leak definition
- Valero Refining, Corpus Christi, TX – valves and connectors subject to 500 ppmv leak definition, pumps and compressor seals subject to 2000 ppmv leak definition
- Pursuant to Texas Regulation 28MID, each of the above-listed facilities must also comply with the following: "All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored."
- Based on conversations with personnel at South Coast AQMD in California, the leak definition levels implemented in that district also are lower than those proposed by the applicant, and that agency requires the use of bellows valves for all new piping having a nominal diameter up to and including 8 inches. This equipment standard is more stringent than the BACT proposed by the applicant. [The applicant did identify bellows valves as an available control option in Section 6.5.2 of the permit application, but provided no further evaluation and did not propose the use of these valves as part of its BACT determination.] We are awaiting detailed information for specific installations from the South Coast AQMD.

- Thus, lower leak definition levels than those in 40 CFR part 61 subpart V and more stringent equipment standards (e.g., bellows valves, leakless pump and compressor seals) than those proposed by the applicant are technically feasible for petroleum refineries. In order to justify less stringent control measures, the applicant must demonstrate that energy, economic, or other environmental impacts of the more stringent alternatives are overwhelming.

Rail and Truck Loading Racks

- The applicant's emission calculations and proposed BACT determination for the product loading operations are somewhat unclear:

- Section 6.7.1 of the permit application states that product loading operations will utilize a vapor collection system, that the collection system will vent to a thermal destruction device (i.e., loading rack thermal oxidizer, EP-17), and that the this device will deliver "greater than 99 percent control efficiency." This section provides no indication as to which loading racks (i.e., which products) will utilize the vapor collection system and thermal oxidizer.
- Section 6.7.3 of the permit application states that the facility is subject to 40 CFR part 63 subpart R, which limits VOC emissions from the control device to 10 milligrams per liter of gasoline loaded. [This regulation does not apply to loading of products other than gasoline.]
- In Section 6.7.4 of the permit application, the applicant proposes as BACT the use of a thermal oxidizer delivering greater than 99 percent control efficiency, but also states that the facility will achieve a combined capture/control efficiency in excess of 96 percent.
- VOC emissions from transfer of gasoline and selected other products (i.e., alkylate, ether, ethanol), as documented in Table B-14 in appendix B to the application, are based upon a capture/control efficiency of 99.2 percent. Estimated VOC emissions from the transfer of other products appear to be based on zero control efficiency.
- The calculated emissions from the gasoline loading arms are 75,460 pounds per year, based on an annual throughput of 938.6 million gallons. This is approximately equivalent to VOC emissions of 10 mg/liter of gasoline, which is consistent with the cited MACT standard.

- Thus, it appears that the applicant is proposing as BACT an emissions level of 10 mg/liter for gasoline loading; 99.2 percent control efficiency for loading of alkylate, ether, and ethanol; and no control for loading of other products. Based on this presumption, we have attempted to evaluate the applicant's BACT analysis, considering available information that should be identified in the BACT analysis.
- The applicant did not sufficiently demonstrate that the proposed capture and control systems represent BACT for gasoline loading. When proposing BACT for gasoline loading operations, the applicant must consider a control efficiency higher than that required by 40 CFR part 63 subpart R. The applicant must also consider in its BACT analysis the use of a recovery system, which may be able to achieve comparable VOC control efficiencies without emitting combustion-related pollutants, instead of a thermal oxidizer. Based on only a preliminary review of available data, we have identified at least one refinery having more stringent VOC control efficiency requirements for gasoline loading than that proposed by the applicant:
    - Koch Refining, Corpus Christi, TX – operates both a vapor recovery unit (VRU), consisting of parallel carbon adsorption units, and a vapor combustion unit (VCU). VOC emissions from the VRU are limited to 0.0625 lb per 1000 gallons of gasoline loaded, or approximately 7.5 mg/liter. The

VCU is required to achieve minimum VOC destruction efficiency of 98 percent. The VRU is required to be equipped with a hydrocarbon CEMS.

- In addition, based on conversations with personnel at South Coast AQMD in California, new and modified gasoline loading operations in that district must achieve a VOC control efficiency of 99.9 percent. This is substantially more stringent than the emissions levels proposed by the applicant. We are awaiting detailed information for specific installations from the South Coast AQMD.

- The applicant did not present any BACT analysis for VOC emissions from loading of products other than gasoline. Table B-14 in appendix B to the application indicates that estimated VOC emissions from these operations is 462 tons per year and that no control of these emissions is planned. The applicant must perform a BACT analysis for the loading racks taking into account the loading of all VOC-containing products. Based on only a preliminary review of available data, we have identified several refineries with VOC control efficiency requirements for non-gasoline loading operations. We recommend that the applicant consider these requirements in performing its BACT analysis:
    - Phillips Petroleum, Borger, TX – required to use a vapor collection system and to vent collected vapors to a control device achieving a minimum VOC destruction/removal efficiency of 98 percent when loading any product with a vapor pressure of 0.5 psia (at 100 °F) or greater.
    - Lyondell-Citgo Refining Co., Houston, TX – required to use a vapor collection system and to vent collected vapors to a thermal oxidizer achieving a minimum VOC destruction efficiency of 98 percent when loading any product with a true vapor pressure of 0.5 psia or greater.

Storage Tanks

- The applicant did not sufficiently demonstrate that the proposed control efficiency of 95 percent for the tank farm thermal oxidizer represents BACT.
- The applicant identified and acknowledged several facilities in the RACT/BACT/LAER Clearinghouse with more stringent VOC destruction efficiency requirements than the proposed 95 percent:
    - CA-0419, 99 percent
    - CA-0504, 99 percent
    - CA-0518, 99 percent
- The applicant did not make a demonstration that a destruction efficiency of 99 percent is not achievable or that the energy, economic, or other environmental impacts of such efficiency are overwhelming.

Wastewater Treatment

- The applicant did not sufficiently demonstrate that the proposed VOC emissions reduction measures, consistent with 40 CFR part 60 subpart QQQ, represent BACT. This regulation requires the following:
    - Combustion devices achieve 95 percent VOC reduction, minimum temperature of 1500 °F, three-hour average
- Based on only a preliminary review of available data, we have identified one refinery with more stringent limits than those in NSPS subpart QQQ as proposed by the applicant:
    - Valero Refining, Corpus Christi, TX – thermal oxidizer serving oil-water separator required to achieve VOC destruction efficiency of 98 percent and minimum temperature of 1600 °F, five-minute average

Cooling Towers

- The applicant did not provide a sufficient basis for its estimate of particulate matter emissions from the induced-draft wet cooling tower (EP-V1).
    - Based on the information provided in Section 3.7 of the permit application and Table B.9 in appendix B to the permit application, the PM-10 emission estimate is based on the emission factor presented in AP-42 Table 13.4-1. This emission factor assumes 0.020 percent total liquid drift, and is representive of units without mist eliminators.
    - The applicant proposes to use high-efficiency mist eliminators and assumes a control efficiency of 99 percent in calculating PM-10 emissions from the cooling tower.
    - The applicant's calculation implies a total liquid drift of 0.0002 percent. To our knowledge, no mist eliminator or cooling tower equipment vendor is providing guarantees for a drift level this low. Recent PSD permits have included BACT determinations requiring the use of mist eliminators designed to achieve 0.002 to 0.004 percent total liquid drift.
- The applicant's VOC emission estimate for the cooling tower, presented in Table B.9 in appendix B to the permit application, is based on the emission factor for uncontrolled cooling water systems presented in AP-42 Table 5.1-2.
- The applicant did not present a BACT analysis for VOC emissions from the wet cooling tower (i.e., the heat transfer system). The permit application must include this analysis which, at a minimum, should address the heat transfer system work practice requirements of the HON (40 CFR part 63, subpart F, §63.104).

- Based on only a preliminary review of available data, we have identified several refineries with permit requirements similar to those set forth at §63.104:
    - Clark Refining, Port Arthur, TX
    - Diamond Shamrock, Three Rivers TX
    - Fina Oil & Chemical, Port Arthur, TX
    - Exxon Company USA, Baytown, TX
    - Koch Refining, Corpus Christi, TX
    - Lyondell-Citgo Refining Co., Houston, TX
    - Marathon Ashland Petroleum, Texas City, TX
    - Phillips Petroleum, Borger, TX
    - Shell Oil, Deer Park, TX
    - Valero Refining, Corpus Christi, TX

Petroleum Coke Handling

- The applicant did not provide sufficient information regarding the basis for its PM/PM-10 emission calculations for petroleum coke handling operations.
    - Section 3.8 of the permit application indicates that emissions estimates are based upon emission factors from AP-42 with "varying control efficiencies (70 or 95 percent) as a result of water sprays at specific transfer points. These control efficiencies are base [sic] on information obtained from TNRCC." No specific citation or basis for the control efficiency information is provided.
    - The emission calculations presented in Table B.11 in appendix B to the permit application indicate that control efficiencies ranging from 75 percent to 99.5 percent were assumed by the applicant, but no basis for these efficiencies is provided.
    - The footnotes to Table B.11 indicate that baghouse(s) will be used to control emissions from several conveyor transfer points, but no BACT analysis for these devices is provided. Based on information in the RACT/BACT/LAER Clearinghouse, current BACT levels for fabric filters are approximately 0.002 to 0.003 grains per dry standard cubic foot of exhaust gas.

Other Fugitive Dust Sources

- Other than the coke handling system, the applicant did not identify any sources of fugitive particulate matter emissions (e.g., vehicle traffic on paved roads). The permit

application must include estimates of these emissions, and fugitive dust control measures (i.e., wetting of paved roads) must be addressed in the BACT analysis.

CTS 37234

URS

01 JUL -2 PM 12:07

URS Job No.: E1-00001776.00

29 June 2001

Mr. John Greenbank
Arizona Clean Fuels, LLC
10201 South 51st Street, Suite 180
Phoenix, AZ 85044

Subject: Revised Sections and Appendices for Class I / Prevention of Significant Deterioration Air Quality Permit Application for Arizona Clean Fuels Refinery

Dear John:

Enclosed are three copies of the revised Best Available Control Technology (BACT) and Emission Inventory sections and their associated appendices to replace those sections from the December 1999 submittal of the PSD Air Quality Permit. Additional copies have been forwarded to representatives at the Arizona Department of Environmental Quality (ADEQ) and RTP Environmental Associates, Inc. for their review. These sections have been modified in response to the comments issued by RTP Environmental Associates in March 2000. Some sections of this report are still pending, including the response to comments matrix. These will be forwarded to the persons copied below.

If you have any questions pertaining to this, please call me at (602) 861-7451.

Sincerely,

for

Robert Farmer
Project Manager

Enclosure (3 copies)

c: Jack Adams, 3 copies
Colin Campbell (RTP), 3 copies
Prabhat Bhargava, 3 copies

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CvrLtr-Revised Sections_6-28.doc

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RTP Environmental Associates, Inc.

Memo

To: Shudeish Mahadev, ADEQ Task Assignment Manager

From: Colin Campbell and Tom Emmel

Date: August 2, 2001

CC: John Greenbank, Arizona Clean Fuels LLC
Bob Farmer, URS

Re: Task Assignment 98-0022AC-02 – Preliminary BACT Review

We have completed a preliminary review of the BACT analysis presented in the Arizona Clean Fuels LLC Revised PSD permit application materials dated June 29, 2001. This memo presents outstanding issues resulting from that review:

General

- The BACT analyses do not in most cases eliminate the highest level of control/lowest emission limit based on either technical/economic/environmental/energy feasibility determinations. In many cases the lowest emission rate found in RTP's review of permits are found in our memo to you dated March 17, 2000.
- BACT analyses are not performed for many emission sources (e.g., CCR Regenerator Vent) or for all PSD significant pollutants for a particular source (e.g., NOx for SRU/TGTU). In most cases this will take little effort on the applicant's part since the applicant has already identified the only feasible control based on BACT for another pollutant.

Refinery fuel gas-fired combustion units

NO_X BACT

- Although $SCONO_X$ was identified as an available control technology, insufficient information/justification is provided to eliminate this technology based on technical or economic bases. This information can be obtained by contacting Goal Line Environmental Technologies, L.L.C. or Alstom Power. Note that this issue was recently

addressed by the U.S. EPA Environmental Appeals Board. (See *In re: Three Mountain Power, LLC, PSD Permit No. 99-PO-01, PSD Appeal No. 01-05*)

- The applicant did not sufficiently demonstrate that SCR is technically or economically infeasible at the lowest emission limits found in RTP's permit review as follows:
    - Chevron Products Co., El Segundo CA – hydrogen reforming furnace equipped with SCR, limited to 5 ppmv NO_X
    - Tosco Refining Co., Wilmington, CA – hydrogen reforming furnace equipped with SCR, limited to 7 ppmv NO_X.

CO BACT

- Although $SCONO_X$ was identified as an available control technology, insufficient information/justification is provided to eliminate this technology based on technical or economic bases.
- The applicant did not sufficiently demonstrate that the proposed CO level (0.04 lb/MMBtu) is the lowest level achievable with low-NO_X burners or ultra-low-NO_X burners. Justification as to why a CO emission limit of 0.008 to 0.016 lb/MMBtu is not BACT (limits found for ULNB+SCR) must be provided. Just because the lowest permit limit for ULNB is 0.04 lb/MMBtu, is not sufficient justification given that SCR technology is not known for reducing CO emissions.

VOC BACT

- Although $SCONO_X$ was identified as an available control technology, insufficient information/justification is provided to eliminate this technology based on technical or economic bases.
- The applicant did not sufficiently demonstrate that the proposed VOC level (0.004 lb/MMBtu) is the lowest level achievable considering that the applicant identified a permit limit of 0.001 lb/MMBtu as the lowest achievable limit.

SO_2 BACT

- The applicant did not evaluate the feasibility of add-on SO_2 control for any fired units.
- Even if the applicant makes an adequate demonstration that no add-on controls for SO_2 emissions are feasible, the applicant has not sufficiently demonstrated that the proposed SO_2 emission level (equivalent to a fuel gas sulfur content of 100 ppmv) represents BACT for refinery fuel-gas fired units given at least one permit/rule suggests that 40 ppmv is technically achievable (South Coast AQMD Rule 431.1 prohibits the burning of refinery fuel gas having a sulfur content in excess of 40 ppmv). ADEQ must consider the fact that this regulatory standard exists when evaluating whether the limit proposed by the applicant represents BACT.

PM/PM-10 BACT

- Based on only a preliminary review of available data, we have identified one refinery with PM/PM-10 emission limits for refinery fuel gas-fired combustion units more stringent than that proposed by the applicant: Koch Refining, Corpus Christi TX – one heater limited to

0.0035 lb PM-10 per MMBtu heat input. As such, this emission limit must be demonstrated not to be BACT.

- We have some concern as to the technical achievability of the emission limit (0.005 lb/MMBtu) proposed as BACT for units equipped with SCR. The applicant should address the impact of ammonia salt emissions on PM10 emission limits for those boilers/heaters to be equipped with SCR.

Sulfur Recovery Unit

- The applicant did not present any BACT analysis for the SRU for pollutants other than SO_2. For example the Koch Refining, Corpus Christi, TX has BACT emission limits of 50 ppmv NO_X (equivalent to ~ 0.05 lb/MMBtu) and 10 ppmv H2S in tail gas incinerator exhaust. BACT analyses must be conducted for all of pollutants that are significant as a result of the project for each source emitting these pollutants.

Process Piping / LDAR

- The applicant did not sufficiently demonstrate that the proposed LDAR program with 500 ppmv and 2000 ppmv leak definition is BACT because the technical/economic feasibility of 100 ppmv leak definition was not addressed.
- Also, insufficient economic/technical justification is provided for excluding leakless equipment. Statements such as "if such pumps are available, their use is cost-prohibitive and does not deliver reasonable cost effectiveness for the quantity of emission abated" are not sufficient support without specific cost estimates. Also, qualitative criteria such as "ACF will consider their use since this effectively reduces LDAR burden" are insufficient as a BACT determination.
- The facility proposed VOC emissions from fugitive equipment leaks are five to ten times greater than would be expected with the LDAR program proposed as BACT. The emission estimates need to reflect the leak detection levels proposed as BACT.

Rail and Truck Loading Racks

- The applicant does not consider or eliminate the use of thermal oxidation after the application of regenerative adsorption. Considering the high cost effectiveness (i.e., low $/ton values) of these controls, the cost effectiveness of the combined control option needs to be evaluated as the highest level of control.

Storage Tanks

- The applicant did not sufficiently demonstrate that thermal oxidation or recovery of VOC's from tanks (in combination with or instead of floating roofs) as being cost ineffective or technically infeasible. Statements such as "vapor recovery and destruction

are not technically feasible or cost effective for floating roof tanks" are insufficient justification for demonstrating economic infeasibility.

Wastewater Treatment

- The applicant has not provided additional information responding to the comments submitted previously and has not addressed other pollutants other than VOCs.

Cooling Towers

- The applicant has not provided any additional information responding to the comments submitted previously with regard to the level of control achievable with high-efficiency drift eliminators. Note that ADEQ is now aware of high-efficiency drift eliminators achieving 0.0005% total liquid drift, whereas the applicant's calculations are based upon 0.0002% liquid drift.
- The applicant needs to provide an evaluation of dry, air-cooled condensers as a better-controlled alternative to wet cooling towers with high-efficiency drift eliminators. This evaluation should address the achievable reductions in both VOC and PM/PM10 emissions.

Petroleum Coke Handling

- The applicant has not provided additional information responding to the comments submitted previously. Additionally, the applicant needs to eliminate the total enclosure of the coke pad area based on technical or economic infeasibility.

Other Fugitive Dust Sources

- Other than the coke handling system, the applicant did not identify any sources of fugitive particulate matter emissions (e.g., vehicle traffic on paved roads). The permit application must include estimates of these emissions, and fugitive dust control measures (i.e., wetting of paved roads) must be addressed in the BACT analysis.

URS

01 NOV -2 12:59

October 31, 2001

Mr. Eric Massey
Air Quality Division
Arizona Department of Environmental Quality
3003 North Central Avenue
Phoenix, Arizona 85012

Re: Submittal of BACT Addendum and
Ambient Air Impact Analysis Materials
for Arizona Clean Fuels
Application No. 10011205

Dear Mr. Massey:

As you are aware, Arizona Clean Fuels, LLC (ACF) has been preparing responses to comments regarding its above referenced Class I air quality permit application (submitted December, 1999) for their planned refinery Mobile, Arizona.

We submit on behalf of ACF the enclosed materials related to this application:

- BACT Analysis Supplement – Contains rewritten BACT analysis sections, which replace in their entirety the corresponding sections submitted previously.
- Air Quality Analysis Protocol – for review and comment
- Interim Air Quality Impact Analysis – covering initial analyses competed to date.

Copies of these materials have been forwarded to RTP Environmental Associates. We sincerely appreciate your cooperation, guidance, and assistance to ACF and URS staff through this process. Should you have any questions regarding this ongoing project, please do not hesitate to contact me at (602) 861-7451.

Sincerely,
URS Corporation

Robert W. Farmer, Ph.D., P.E.
Team Leader, Air Quality Services

Enclosures

CC: J. Greenbank, ACF
J. Adams, ACF
P. Hyde, ADEQ
R. Graw, RTP
C. Campbell, RTP

URS Corporation
7720 North 16th Street, Suite 100
Phoenix, AZ 85020
Tel: 602.371.1100
Fax: 602.371.1615

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44226

November 16, 2001

Mr. Eric Massey
Air Quality Division
Arizona Department of Environmental Quality
3003 North Central Avenue
Phoenix, Arizona 85012

Re: Submittal of BACT Addendum – 2
for Arizona Clean Fuels
Application No. 10011205

Dear Mr. Massey:

As you are aware, Arizona Clean Fuels, LLC (ACF) has been preparing responses to comments regarding its above referenced Class I air quality permit application (submitted December, 1999) for their planned refinery Mobile, Arizona.

We submit on behalf of ACF the enclosed BACT Analysis Supplement – 2 related to this application. This supplement addresses reviewer comments by presenting a revised BACT analysis for:

- Process heaters and boilers (CO, VOC, PM10 and SO2);
- Petroleum liquid storage tanks (VOC); and,
- Petroleum liquid loading racks (VOC).

We sincerely appreciate your cooperation, guidance, and assistance to ACF and URS staff through this process. Should you have any questions regarding this ongoing project, please do not hesitate to contact me at (602) 861-7451.

Sincerely,
URS Corporation

Robert W. Farmer, Ph.D., P.E.
Team Leader, Air Quality Services

Enclosure – BACT Analysis Supplement – 2, (2 copies)

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Phoenix, AZ 85020
Tel: 602.371.1100
Fax: 602.371.1615

CC: J. Greenbank, ACF
J. Adams, ACF

URS

March 14, 2002

Mr. Eric Massey
Air Quality Division
Arizona Department of Environmental Quality
3003 North Central Avenue
Phoenix, Arizona 85012

Re: Submittal of Revised Application Sections
And Appendices - 2
for Arizona Clean Fuels, LLC
Application No. 10011205

Dear Mr. Massey:

As you are aware, Arizona Clean Fuels, LLC (ACF) has been preparing responses to comments regarding its above referenced Class I air quality permit application (originally submitted December 1999) for their planned refinery Mobile, Arizona. On behalf of ACF, we are submitting herein revised and supplemental materials for this application. These sections have been modified in response to the comments issued by RTP Environmental Associates in March 2000, August 2001, and January 2002.

The Best Available Control Technology (BACT) and Emission Inventory sections and their associated appendices provided will replace or append to indicated sections from previous submittals related to this PSD Air Quality Permit. In this submittal, the revised sections are comprised of:

- Revised Emission Inventory (Section 3) which largely replaces the most recent submitted version of this section (June, 2001).
- BACT Analysis Supplement (Section 6) – Contains new and revised BACT analysis sections, which replace or append to sections submitted previously.
- Appendix B Supplement – Emission Inventory supporting materials
- Appendix F Supplement – BACT Analysis supporting materials

Copies of these materials have been forwarded to RTP Environmental Associates. We sincerely appreciate your cooperation, guidance, and assistance to ACF and URS staff through this process. Should you have any questions, please do not hesitate to contact me at (602) 861-7451.

Sincerely,
URS Corporation

Robert W. Farmer, Ph.D., P.E.
Team Leader, Air Quality Services

Enclosures

CC: J. Greenbank, ACF
J. Adams, ACF
R. Graw, RTP
C. Campbell, RTP

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URS

April 24, 2002

Mr. Colin Campbell
RTP Environmental Associates, Inc.
304-A West Millbrook Road
Raleigh, NC 27609

Re: Response to Comments; Arizona Clean Fuels, LLC
Class I Air Permit Application
URS Job No. E100001776.00

Dear Mr. Campbell:

We have received from RTP Environmental Associates (RTP) a number of comments and requests for clarification regarding the Arizona Clean Fuels (ACF) Class I Air Permit Application (No. 1001205). The Class I application was originally submitted in December 1999. In part, these recent comments are based on review of application supplements from ACF dated October 2001, November 2001, and March 2002. This letter, submitted on behalf of ACF, conveys our responses to most of these comments based on the best information available at this time. Additional materials, in particular Compliance Assurance Monitoring (CAM) Approach submittals are now being completed and will be submitted in early May 2002.

Routing of Vent Gases from Hydrogen Plant: As shown in Figure A-7 from the December 1999 application, vent gases potentially containing hydrocarbons are released from the Steam Drum (V-07300) and the Pressure Swing Adsorption (PSA) unit (S-07400). The vent from the Steam Drum is split between the superheated steam system of the refinery and a recycle to the Methane Reformer process inlet. Hydrocarbons in this stream would be converted in the Reformer and Shift Reactor. The purge gases from the PSA unit are fed to the combustion chamber of the Reformer, along with fuel gas, and are combusted. Consequently, there are no uncontrolled process vents from the ACF Hydrogen Plant.

Three SRU Tanks not included in BACT: There are three process tanks on the Outside the Battery Limit (OSBL) Tankage List (dated 20 January 1999 and included in Appendix C of the December 1999 application) that are associated with the Sulfur Recovery Unit (SRU). These tanks (T-11100, T-12200, and T-13440) were not addressed in the ACF BACT analysis for tank VOC emissions. Taken collectively, these tanks do not have sufficient VOC emissions to warrant addition to the

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vapor recovery system for treatment by the Tank Farm Thermal Oxidizer (EP-16). The calculation below estimates the annual VOC emissions, annualized cost, and cost effectiveness.

Conservative estimates of annual VOC emissions were obtained using TANKS4.0, with diethylamine as a surrogate for diethanolamine absorbent solution. This analysis indicates the two amine tanks (T-12200 and T-13440) combined may emit up to 7,500 lb/yr VOC. The Sour Water tank (T-11100) was modeled as a water tank having a separated layer of hydrocarbon liquid assumed to resemble Diesel No. 2. This tank may release up to 525 lb/yr VOC. Preliminary dimensions for the tanks and material throughput as noted in the December 1999 tankage list were used for the TANKS4.0 model.

For annualized cost increment, refer to Table 6.4-2 in the November 2001 submittal, which summarizes the BACT cost analysis for adding a thermal oxidizer to existing storage tanks. It was estimated that the annualized cost for a vapor capture and thermal oxidizer system treating releases from 27 tanks was $602,926/year. Prorating on a per tank basis, these costs are $$23,307/tank/year. To add three more tanks to the proposed Tank Farm oxidizer would be about $66,900/year (= 3 x $23,300/yr).

Translating these estimates into a cost effectiveness ratio, abating a maximum of 4 tons of emissions from these three tanks, at an annualized cost of $66,900, yields $16,730 per ton abated. This indicates that it is cost prohibitive to apply a thermal oxidizer to control emissions from the SRU solution tanks.

Compliance Option for Group 1 Wastewater Streams under 40 CFR 61, Subpart FF: The wastewater treatment plant at the ACF facility should be assumed to have greater than 10 Megagram (Mg)/year loading of benzene, and thus require controls pursuant to Subpart FF (40 CFR 61.342). The method to be used for control was identified in Section 2.20.3.4 of the December 1999 ACF application. Four process vessels in series act to reduce the benzene/THC content in process wastewater and run-off waters; these are the API Separator, Dissolved Air Flotation unit, Equalization tank, and Powdered Activated Carbon Bio-treater. The water effluent from the Bio-treater will have negligible residual benzene or hydrocarbon content, which will comply with the 10

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ppmw standard in 40 CFR 61.348 (a)(1)(i), or (b)(2)(i). A Thermal Oxidizer (EP-18) will treat air drawn from these four WWTP process vessels to maintain their headspaces at negative pressure. This oxidizer will operate at no less than 95% destruction efficiency for VOC, on a mass basis. Estimated emissions for EP-18 are shown in Table B.2, as revised in the March 2002 submittal.

Applicability of NSPS Subpart NNN to Butane/Propane Distillation Units: As pointed out in a comment from RTP on 3/19/02, the depropanizer and debutanizer columns in the Gas Plant and the stabilizer column in the Butane Conversion unit produce propane and/or butane which are listed SOCMI chemicals for this Subpart. Reference to Figures A-3 and A-12 in the December 1999 application confirms that these distillation units produce mixed propane and butanes. The light ends (distillate) streams from these columns are condensed under pressure and pumped without further treatment to any of 6 storage spheres at the refinery. These materials would be shipped from the ACF plant as feedstock for production of Liquified Petroleum Gas (LPG). The columns, their condensers, and condensate pumps would be affected facilities as defined in Subpart NNN, since this process represents a; "combination of two or more distillation units and the common recovery system into which their vent streams are discharged." (40 CFR 60.660(b)(3)).

The complete capture of the overhead or "vent" streams from the distillation units by condensation should be viewed as the method of compliance for this Subpart. Prior to availability of design material balances for the columns, the "emission rate" of material from the columns, and the corresponding TRE index cannot be estimated. However, ACF proposes that the compliance option in 40 CFR 60.662 (c) should be applied; "Maintain a TRE index value greater than 1.0 without the use of VOC emission control devices." Further, the distillation column condensers should be viewed as the "final recovery device" for purposes of the monitoring procedure in 40 CFR 60.663(e)(2)(i), and a "condenser exit (product side) temperature monitoring device with a continuous recorder" will be implemented for each unit, as specified in that paragraph.

Applicability of MACT Subpart CC to Butane Conversion Unit Regenerator Vent: As noted in RTP comment 2 from March 19th, the materials submitted do not discuss the exemption for this vent from the MACT Subpart CC requirements. This particular unit uses perchloroethylene (as source of chlorine) to chemically regenerate catalyst from the Dehydrogenation Reactor (V-15300) in the

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Butane Conversion (InAlk) process unit. The operation of the Regeneration Unit (V-15340) is described in Section 2.11, and illustrated in Figure A-12, of the December 1999 ACF application. Upon review, we conclude that none of the HAPs listed in Table 1 of 40 CFR 63 Subpart CC will be "contacted or contained" in this equipment, and the vent should be exempt from the Subpart CC requirements.

Solid catalyst to be regenerated is circulated from the Dehydrogenation Reactor, which processes a feed stream that is primarily isobutane (C_4) and creates octane isomers (C_8) by "dimerizing" or polymerizing the butane molecules. Neither of these alkane hydrocarbon families are represented in the Table 1 list. In the regenerator, several steps occur to regenerate the catalyst. Small quantities of hydrochloric acid and chlorine are generated by decomposition of perchloroethylene. However, these compounds involved in the regeneration step are also not listed in Table 1 of Subpart CC. Emissions from the Butane Conversion Unit Catalyst Regenerator are shown in Table B.8 of the March 2002 application supplement.

Storage tank capacity for amine solution and sour water streams to accommodate 24-hours of SRU downtime: To satisfy BACT criteria for the amine treater section of the SRU, ACF has indicated in the March 2002 BACT Supplement that it would revise the storage tank capacity for amine absorbent solutions and sour water streams that would be received by the SRU. The originally proposed tankage (tabulated in Appendix C of the December 1999 application) is based on retaining sufficient inventory of these solutions to support normal operations.

Additional surge capacity to accommodate an outage of the SRU and amine regeneration has been added. The tanks and their revised sizes are listed below. The sizes are based on a potential of no less than 24 hours of surge volume to assure adequate size to accommodate brief downtime of the SRU or amine regeneration processes. Please note that these systems are highly reliable and this volume is unlikely to be utilized, but ACF understands that avoiding excess emissions is a component of the BACT measures for the SRU.

T-11100: Sour Water Stripper Feed Prep Tank, Revised working volume 90,000 bbls

T-12200: Amine Unit DEA Tank, Revised working volume 5,000 bbls

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T-13440: Tail Gas Treater Unit MDEA Tank, Revised working volume 600 bbls

Applicability of NSPS Subpart Kb to WWTP tanks: As noted in comment 5 from RTP on March 19th, the application submittals to date have not addressed the applicability of NSPS Subpart Kb to four Waste Water Treatment Plant (WWTP) vessels that will contain water with entrained hydrocarbon. These vessels are the API separator, dissolved air flotation unit (DAF), equalization tank, and the powder activated carbon (PAC) biotreater. These operations have been designed to occur in enclosed vessels in order to control VOC emissions. The plant's design is based on a maximum hourly flow rate of 1000 gpm. Assuming a minimum holding time of one hour, the vessels must be $\geq$ 60,000 gals. Consequently, the more conservative approach is for these vessels to be subject to Subpart Kb.

These vessels will be subject to the following requirements:

a) 60.110b(a) – Applicability - Vessels are > 40,000 gals and will be constructed after July 23, 1984.

b) 60.112b et al – For true vapor pressure > 5.2 kPa, vessels will require VOC control. If the liquid contents are assumed to have a layer of benzene in contact with the headspace, this top VOC layer would have a representative vapor pressure of 100 mmHg (13.3 kPa) at 26 °C (Perry's Handbook, 6th Edition, Table 3-8). To achieve compliance, these four vessels will be vented to the WWTP Thermal Oxidizer (EP-18) which will operate with at least 95% as stipulated by Refinery MACT (40 CFR 63, Subpart CC). There may be hydrocarbons of higher volatility than benzene in the treated wastewater.

c) 60.113b – These vessels will require tank, roof, and seal inspections and an operating plan for the control device.

d) 60.115b and .116b – Units will be included in reporting and record keeping requirements.

Applicability of NSPS Subpart D to Refinery Steam Boilers: The new steam boilers proposed for the ACF facility will be fired primarily with pipeline natural gas, with the capability to supplement with

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refinery fuel gas. The units are rated at a heat input of 419 MMBTU per hour (Table B.1, March 2002 submittal), and subsequently will be subject to NSPS Subpart D. The original application incorrectly states that these units will be subject to Subpart Db (for units greater than 100 MMBtu/hr heat input rating). As the boilers will combust only gaseous, low sulfur fuels, the compliance requirements should be minimal for these units under the NSPS.

BACT for hydrogen sulfide (H_2S) emissions from sulfur loading operations: Comment 1 from RTP dated March 20th asks that BACT be proposed for the sulfur loading operations. As described in the ACF application of December 1999 (Section 2.15.1) a steam-powered ejector draws sweep air from the Sulfur Pit (actually a storage vessel for molten sulfur) and routes this stream to the SRU thermal oxidizer unit (EP-12) for treatment of H_2S vapor by oxidization to SO_2. The application is silent on the BACT measures for the loading of molten sulfur to tank trucks or rail cars. ACF recognizes that degassing technology is demonstrated in practice and is the currently accepted BACT for this source. Consequently, ACF will add a degassing step to degass the molten sulfur to no more than 15 ppmw as H_2S prior to loading.

Clarification of the Configuration for Loading and Unloading Racks: As pointed out in comment 2 from RTP of March 20th there are a few inconsistencies in the description of the loading and unloading operations to be conducted.

a) Railcar loading for transportation fuels: The application materials submitted to date do not include railcar loading for transportation fuels. Recently, ACF has seen value in having the flexibility to have an alternative to truck loading only, so request that this capability be provided for in this permit. Consequently, the facility equipment list will be modified by adding a number of railcar loading racks for fuels (gasoline, diesel, and jet fuel) that will be determined. Also, a new thermal oxidizer of identical size and emissions (on a maximum design capacity basis) will be added, and is to be identified as EP-27.

b) Materials identified as gasoline additives (alkylate, ethanol, and ether(s)) will only be unloaded from railcars at the ACF facility. However, ACF accounted separately for emissions associated with the transfer operation at the unloading racks (Table B.14), and the

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working/breathing losses from the storage tanks (Table B.12). The former source was estimated using a generic AP-42 factor for gasoline operations (corrected if appropriate for vapor pressure). The tank breathing/working losses were determined with the TANKS model. The unloading losses will likely be controlled by the new Railcar Loading/Unloading Rack thermal oxidizer (EP-27) described above. The storage tank losses will be captured and treated by the Tank Farm thermal oxidizer (EP-16).

c) This comment mentions a statement that in the ACF November 2001 submittal that gasoline additive *loading* operations will have controlled VOC emissions. This is likely a typographical error, which should have read *unloading* operations. As stated in item (b), these emissions will now likely be controlled by the Railcar Rack thermal oxidizer (EP-27).

Will ACF Own/Operate Delivery Vessels Subject to County Rule 352: As permit holder for the refinery, ACF will not own or operate gasoline delivery vessels.

Vapor Pressure Limitation for Non-gasoline Products Subject to County Rule 351: It is anticipated that ACF will accept in its permit a limitation of 1.5 psia as a maximum VOC true vapor pressure for non-gasoline products (except for LPG, Propane and Butane.) These products will include No. 2 diesel fuel and No. 4 aviation jet fuel, each of which have true vapor pressures below this limitation.

Emission Estimates for Tank Farm Thermal Oxidizer: Comment 5 from RTP on March 20th asks for clarification between the June 2001 submittal, which omitted the Tank Farm thermal oxidizer (EP-16) and the March 2002 submittal that reinstates this unit. The control afforded by this oxidizer was adopted by ACF as BACT, so the more recent submittal is correct.

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ACF appreciates the opportunity to respond to comments relating to the pending Class I permit. Rather than submit another application supplement, we anticipate that the information provided in this letter can be incorporated in the final, composite version of the application package to be constructed for public comment. Please advise if a supplement should be submitted separately on the issues discussed in this letter.

Please do not hesitate to contact me if there should be further questions or information needs.

Sincerely,

URS Corporation

Robert W. Farmer, Ph.D., P.E.
Team Leader, Air Quality Services

RWF/tc

cc: S. Mahadev, ADEQ
J. Adams, ACF
J. Greenbank, ACF

ARIZONA DEPARTMENT
OF
ENVIRONMENTAL QUALITY

Jane Dee Hull
Governor

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Jacqueline E. Schafer
Director

AQD:PS:CTS:60462

September 4, 2002

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

COPY

Mr. John Greenbank
Chief Executive Officer
Arizona Clean Fuels, LLC
3145 E. Dry Creek Rd
Phoenix, AZ 85048

Dear Mr. Greenbank:

Subject: Air Quality Control Permit Number 1001205
Refinery

This letter is in regards to your Air Quality Permit application for a grass-roots Refinery, which is proposed to be located in Mobile, AZ. This application was received by the Arizona Department of Environmental Quality (ADEQ) on December 23, 1999. Thereafter, the application was deemed incomplete on January 31, 2000, because it did not include an analysis of air quality impacts. The air quality impact analysis was submitted to ADEQ on August 23, 2002. After reviewing this submittal, ADEQ has deemed the application to be complete.

This notification of completeness does not imply that ADEQ agrees with any analysis, conclusions, or positions contained in the application. Please be aware that additional, clarifying information may be necessary to complete permit processing. According to Arizona Administrative Code (A.A.C.) R18-2-304.G, you have a duty to supplement or correct this application upon becoming aware of any omission or error contained in it. You are also required to provide additional information, as necessary, to address any new requirements which become applicable after submittal of this application.

If you request a suspension in processing or alter the application for any reason, this completeness determination may cease to apply.

Please note that according to A.A.C. R18-2-302, no person shall commence construction of, operate, or make a modification to any source without first obtaining a permit. Pursuant to Arizona Revised Statute §49-463, any person who violates any permit condition is subject to a civil penalty of not more

than ten thousand dollars ($10,000) per day per violation.

If you have any questions, please contact me at 602) 771-2308 or Shudeish Mahadev at 602) 771-2323.

Sincerely,

Nancy C. Wrona, Director
Air Quality Division

NCW:sm2

cc: Ms. Cathy O'Connell, Compliance Section Manager, ADEQ
Mr. Colin Campbell, RTP Environmental Associates
Mr. Robert Farmer, URS Corporation

Jane Dee Hull
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

3033 North Central Avenue - Phoenix, Arizona 85012-2809
(602) 207-2300 - www.adeq.state.az.us

Jacqueline E. Schafer
Director

Notice of Administrative Completeness

Jack Adams
10201 S 51st St
Ste 180
Phoenix AZ 85044

September 12, 2002

Subject: LTF Tracking ID: 17347
Arizona Clean Fuels

Project ID: 1001205

Dear Applicant:

ADEQ review of your application referenced above is subject to the requirements of the licensing time frames statute under A.R.S. 41-1072 through 41-1079 and the licensing time frames rules under A.A.C. R18-1-501 through R18-1-525. ADEQ has determined that the application is administratively complete in accordance with the licensing time frames statute and rules.

This letter is the written notification of this determination required under A.R.S. 41-1075 and A.A.C. R18-1-503(D). This determination causes the administrative completeness review time frame on your application to end and the substantive review time frame to begin.

Please contact the undersigned if you have questions regarding this matter.

Shudeish Mahadev
Arizona Department of Environmental Quality
1110 W Washington St
Phoenix, AZ 85007
(602)771-2323

GALLAGHER & KENNEDY
P.A.
ATTORNEYS AT LAW

J. STANTON CURRY
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ADEQ
03 SEP -5 PM 4:59

September 5, 2003

VIA HAND DELIVERY & U.S. MAIL

Nancy C. Wrona, *Division Director*
ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
1110 West Washington Street
M/C: 3415A-1
Phoenix, AZ 85007

Re: ***Arizona Clean Fuels, LLC***

Dear Ms. Wrona:

In recent weeks, Arizona Clean Fuels, LLC (ACF) has fielded questions from various sources, including the Arizona Department of Environmental Quality (ADEQ), about its Mobile refinery project. ACF understands that ADEQ also receives inquiries from time to time. In order to eliminate any doubt about the answers to certain questions, ACF sends this letter to confirm in writing what ACF previously has stated orally.

ACF is willing to relocate both the local school and the community center as part of the Mobile refinery project. ACF obviously will need to confer with the State, the families served by the school, and the owner of the community center to determine how and when this should be accomplished. Of course, this commitment is conditioned on the Mobile refinery project successfully moving forward.

This also will confirm ACF's previous statement that it is willing to enter a Licensing Time Frames Extension Agreement with ADEQ. ADEQ shared a draft agreement with ACF's representatives on August 29. The terms as proposed in the draft are acceptable. Please send the agreement to me in final form, and ACF will sign it.

Sincerely,

GALLAGHER & KENNEDY, P.A.

By: J. Stanton Curry

JSC/sgc
cc: (via mail)
E. Massey
J. Mikitish, Esq.
T. Huddleston, Esq.
J. Greenbank
1126052/21131-0001

GALLAGHER & KENNEDY
P.A.
ATTORNEYS AT LAW

DAVID P. KIMBALL, III
DIRECT DIAL: (602) 530-8221
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2575 EAST CAMELBACK ROAD
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PHONE: (602) 530-8000
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October 30, 2003

CONFIDENTIAL PERMIT COMMUNICATION

VIA HAND-DELIVERY

Ms. Nancy C. Wrona
ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
1110 West Washington Street
Phoenix, AZ 85007

Re: ***Arizona Clean Fuels***

Dear Ms. Wrona:

On behalf of Arizona Clean Fuels ("ACF"), I want to thank you and your staff for engaging in extensive negotiations, technical analyses, and regulatory reviews in the preparation of an air quality permit for the proposed oil refinery at the Mobile site. These permit discussions have been helpful as ACF has deliberated whether to proceed with the Mobile site or to seek an alternate site in order to avoid the uncertainty of possibly facing new nonattainment regulations in Maricopa County in the future.

This letter will confirm that ACF has decided to relocate the project to Yuma County. Therefore, ACF will not proceed with the Mobile site, and it will not be necessary for ADEQ to issue a proposed permit for the Mobile site. As soon as ACF makes the final decision on a site within Yuma County, ACF will resubmit a permit application and work with ADEQ on processing the permit for the new site. We understand that the extensive work that ADEQ has performed in preparing a permit for the Mobile site will significantly expedite the permitting process for the new site.

Sincerely,

GALLAGHER & KENNEDY, P.A.

By David P. Kimball, III

1138125/21131-0001

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street · Phoenix, Arizona 85007
(602) 771-2300 · www.adeq.state.az.us

Janet Napolitano
Governor

Stephen A. Owens
Director

April 5, 2004

AQD:PS:CTS:

VIA FACSIMILE AND
CERTIFIED MAIL: RETURN RECEIPT REQUESTED

Glenn McGinnis, CEO
Arizona Clean Fuels
4505 E. Chandler Blvd, #145
Phoenix, AZ 85048

Subject: Application for Air Quality Control Permit No. 1001205
Arizona Clean Fuels, LLC

Dear Mr. McGinnis:

As was discussed in our meeting on March 19, 2004, the number of days remaining in the overall time-frames for Air Quality Control Permit No. 1001205 will expire on April 7, 2004. During our meeting, Arizona Clean Fuels, LLC (ACF) indicated that it was pursuing the relocation of its proposed refinery, and had identified a possible location near Mohawk, Arizona. The Arizona Department of Environmental Quality (ADEQ) explained that such a relocation would require ACF to submit a new permit application, and that the number of days remaining in the overall time-frames would not be sufficient for ACF to submit a new application nor allow ADEQ an appropriate amount of time to perform the required review of the application, revise the draft permit, propose a revised draft permit for public notice, and complete EPA's review of a proposed permit.

In order for the Arizona Department of Environmental Quality (ADEQ) to ensure the continued processing of Air Quality Control Permit application no. 1001205, it is necessary for Arizona Clean Fuels and the Department to enter into a Licensing Time-frames Changed Application Agreement pursuant to Arizona Administrative Code (A.A.C.) Title 18, Chapter 1, Article 5, Rule 511, Paragraph A (A.A.C. R18-1-511(A)). In accordance with A.A.C. R18-1-507(D), such an agreement between the Department and the applicant would cause all time-frames on the existing application to end, and would create a new set of time-frames that operate under that agreement.

Pursuant to A.A.C. R18-1-511(B), ADEQ is proposing the following terms of agreement:

(a) All requirements of Arizona Administrative Code, Title 18, Chapter 1, Article 5 remain in effect;

(b) Pursuant to A.R.S. § 41-1004, and in consideration of the Department allowing the applicant to change the information submitted in support of a changed application, Arizona Clean Fuels, LLC waives its rights to the number of time-frame days identified in license tables;

(c) Arizona Clean Fuels will provide the Department with a new air quality application that contains the following information:

(1) Pursuant to A.A.C. R18-2-304(B)(2), the new application will address whether or not the relocated facility will remain designed, controlled, or equipped with such air pollution control equipment that it may be expected to operate without emitting or without causing to be emitted air contaminants in violation of the provisions of A.R.S. Title 49, Chapter 3, Article 2 and A.A.C. Title 18, Chapter 2;

(2) Pursuant to A.A.C. R18-2-304(B)(4) and (E)(5), the application will address whether or not the proposed emission limitations, controls, or other requirements stated in the permit application are necessary, as well address the ability of such conditions to meet the requirements of A.A.C. R18-2-306.01. Such an assessment is required to contain a description of any proposed emissions limitations, controls, or other requirements in the application, along with a description of the proposed associated monitoring, recordkeeping, and reporting requirements necessary to demonstrate that the emissions limitations, controls, or other requirements are permanent, quantifiable, and otherwise enforceable as a practical matter;

(3) Pursuant to A.A.C. R18-2-304(E)(2), the application will address whether or not the relocated source triggers the applicability of the requirements of Arizona Administrative Code, Title 18, Article 4;

(4) Pursuant to A.A.C. R18-2-304(E)(3), the application will address whether or not the redesigned source triggers the applicability of the requirements established pursuant to A.R.S. §§ 49-426.03 and 49-426.06.

In addition to providing the analysis detailed above, ACF will also need to demonstrate to the Department whether or not the ambient concentrations of the pollutants emitted by the relocated equipment are in compliance with the National Ambient Air Quality Standards, and the Arizona Ambient Air Quality Guidelines.

(d) The overall time-frames applicable to the changed application will comprise 20 Administrative Completeness Review days, and 182 Substantive Review days, with all days expressed as business days. The running of days within the overall timeframes will commence upon the submittal of the changed application.

(e) Arizona Clean Fuels agrees to pay all outstanding fees associated with the processing of the application for the Mobile location.

(f) ADEQ will continue to process the new application as a "Complex Class I PSD major source permit with a public hearing"

Because the number of days remaining in the overall timeframes for this application will expire on April 7, 2004, ADEQ requests that your written agreement to these terms be submitted to the Department on or before the close of business on April 5, 2004.

If you have any additional questions, please contact Eric Massey, on my staff, at (602) 771-2288, or me at (602) 771-2308.

Sincerely,

Nancy C. Wrona, Director
Air Quality Division

NCW:ecm

cc. Eric Massey, Arizona Department of Environmental Quality
Joe Mikitish, Attorney General's Office
Stan Curry, Gallagher and Kennedy

Arizona Clean Fuels

88236

ADEQ
AIR QUALITY DIVISION
04 APR -7 AM 10: 25

April 6, 2004

VIA EMAIL & U.S. MAIL

Nancy C. Wrona
ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
1110 W. Washington Street
M/C: 3415A-1
Phoenix, AZ 85007

Re: ***Arizona Clean Fuels, LLC***
Application for Air Quality Control Permit No. 1001205

Dear Ms. Wrona:

Thank you for your April 5, 2004 letter and for your Department's continuing focus on our air permit. Arizona Clean Fuels, LLC (ACF) agrees that it makes sense to enter an agreement to extend the time for the Department to process the permit. Based on our review of your letter and the Department's rule for "Changed Application Agreements" (Arizona Administrative Code (A.A.C.) R18-1-511(B)), ACF proposes the following terms of agreement:

(a) Except for the new time-frames specified in paragraph (d) below, all requirements of Arizona Administrative Code, Title 18, Chapter 1, Article 5 remain in effect;

(b) Pursuant to A.R.S. § 41-1004, and in consideration of the Department allowing the applicant to change the information submitted in support of a changed application, ACF waives its rights to the number of time-frame days identified in the air license tables;

(c) Without limitation upon the requirements for a complete permit application as provided under A.A.C. Title 18, Chapter 2, ACF will provide the Department with a changed air quality application that contains the following new information.

(1) The proposed new location of the source;

(2) An amended site diagram showing the proposed siting and property boundaries of the source at the proposed new location;

(3) Identification of all applicable requirements (as defined at A.A.C. R18-2-101.14) for the source at the proposed new location;

(4) A criteria pollutant ambient air impact analysis for source emissions at the proposed new location, as required by A.A.C. Title 18, Chapter 2, Article 4;

Arizona Clean Fuels, LLC
4505 East Chandler Blvd., Suite 145
Phoenix, Arizona USA 85048-7686
Phone: 480-753-5400 Fax: 480-753-5445
www.ArizonaCleanFuels.com

(5) An Arizona Ambient Air Quality Guidelines (AAAQGs) ambient air impact analysis for source emissions at the proposed new location;

(6) A chronology and summary of ACF's key technical documents and submittals to the Department from the application submittal in 1999 until the present time; and

(7) An updated Standard Permit Application Form.

(d) The overall time-frames applicable to the changed application will comprise 20 Administrative Completeness Review days, and 182 Substantive Review days, with all days expressed as business days. The running of days within the overall timeframes will commence upon the submittal of the changed application. Upon receipt of a complete changed application, the Department will use its best efforts to expedite processing of the permit.

(e) ACF agrees to pay advance payments for the processing of its changed application pursuant to A.A.C. R18-2-326.I.2.

(f) Although, under A.A.C. R18-2-326.I.3, ACF is not required to make payment for previous permit processing until the Department's completion of permit processing activities, ACF agrees to make a good faith partial payment of the costs for previous permit processing. ACF agrees to make this payment to the Department within 30 calendar days of the execution of the Licensing Time-frames Changed Application Agreement.

(g) ADEQ will continue to process the new application as a "Complex Class 1 PSD major source permit with a public hearing."

We believe these terms comply with the rule for "Changed Application Agreements" and are consistent with ACF's and the Department's discussions on March 19 and thereafter concerning the nature of the changed application for the proposed new location. ACF believes that this approach will be mutually beneficial for all concerned, including the public. If you have any questions about this proposal, please feel free to contact me directly at 480-753-5400 or our attorney Stan Curry at 602-530-8222.

Sincerely,

R. Glenn McGinnis
CEO, Arizona Clean Fuels, LLC

Cert Mail #
25575

cc. E. Massey
J. Mikitish
D. Kimball
S. Curry
R. Farmer
1171177/21131-0001

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Terry Goddard
Attorney General

Office of the Attorney General
State of Arizona

Joseph P. Mikitish
Assistant Attorney General
Direct Line: (602) 542-8553

April 6, 2004

VIA FACSIMILE AND MAIL

Mr. J. Stanton Curry
Gallagher & Kennedy
2575 East Camelback Road
Phoenix, Arizona 85016-9225

RE: Arizona Clean Fuels, LLC – Application for Air Quality Control Permit #1001205

Dear Mr. Curry:

The Arizona Department of Environmental Quality received the letter dated April 6, 2004 from Arizona Clean Fuels concerning its air permit application. The Department has authorized me to respond on its behalf. The Department concurs in and agrees to the terms of the agreement to extend the time for the Department to process the permit application set forth in the Arizona Clean Fuels letter. The terms are consistent with the Department's rule for changed application agreements under Arizona Administrative Code R18-1-511(B). The Department understands that, by entering into this agreement, Arizona Clean Fuels waives its rights to the number of timeframe days identified in the air license tables pursuant to A.R.S. § 41-1004. If you have any questions or related issues, please contact me.

Very truly yours,

Joseph P. Mikitish
Assistant Attorney General

JPM/ke

cc: Nancy Wrona, ADEQ
Eric Massey, ADEQ

1275 West Washington, Phoenix, Arizona 85007-2926 Phone (602) 542-8553 Fax (602) 542-7798

URS

93479

ADEQ
AIR QUALITY DIVISION
04 JUL 14 AM 9:35

July 14, 2004

Mr. Eric Massey
Arizona Department of Environmental Quality
Air Quality Division
1110 W. Washington Street
Phoenix, Arizona 85007

Re: Composite PSD/Class I Applications for ACF
URS Job No. 23442821

Dear Mr. Massey:

On behalf of Arizona Clean Fuels Yuma, LLC (ACF), we submit three (3) additional copies of the Composite Air Permit Application for the ACF project in Yuma County. These documents are a compilation of substantive application materials from the original application in December 1999 to date.

Under separate cover, we are submitting identical copies of this document to Mr. Pete Lahm of the US Forest Service, Ms. Emmanuelle Rapicovali of US Environmental Protection Agency, Region IX, and Mr. Don Shepherd of the US National Park Service, Air Resources Division.

Thanks for your attention to forwarding these copies where needed.

Sincerely,
URS Corporation

Robert W. Farmer, Ph.D., P.E.
Practice Leader, Air Quality Services

Encl: Composite Air Permit Application for ACF, 3 copies

cc: E. Rapicovali, US EPA Region IX
D. Shepherd, US National Park Service
P. Lahm, US Forest Service
G. McGinnis, ACF

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