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THE ENVIRONMENTAL PROTECTION AGENCY'S RENEWABLE FUEL STANDARD PROGRAM: CHALLENGES AND OPPORTUNITIES

HEARING

BEFORE THE

COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS

UNITED STATES SENATE

ONE HUNDRED SEVENTEENTH CONGRESS

SECOND SESSION

FEBRUARY 16, 2022

Printed for the use of the Committee on Environment and Public Works



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ONE HUNDRED SEVENTEENTH CONGRESS

SECOND SESSION

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THE ENVIRONMENTAL PROTECTION AGENCY'S RENEWABLE FUEL STANDARD PROGRAM: CHALLENGES AND OPPORTUNITIES

WEDNESDAY, FEBRUARY 16, 2022

U.S. SENATE,
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS,
Washington, DC.

The Committee, met, pursuant to notice, at 10:04 a.m. in room 106, Dirksen Senate Office Building, Hon. Thomas R. Carper (Chairman of the Committee) presiding.

Present: Senators Carper, Capito, Cardin, Whitehouse, Merkley, Stabenow, Inhofe, Cramer, Lummis, Boozman, Wicker, Sullivan, and Ernst.

OPENING STATEMENT OF HON. THOMAS R. CARPER, U.S. SENATOR FROM THE STATE OF DELAWARE

Senator CARPER. Good morning, everybody. I am pleased to call this hearing to order.

Today, we are going to examine the Environmental Protection Agency's Renewable Fuel Standard Program. This includes management and implementation challenges, as well as opportunities to encourage greater deployment of more sustainable fuels. My staff tells me that our Committee has not held an oversight hearing on this topic since 2016. This has gone on 6 years. It is probably time.

To help inform our discussion, we are fortunate to have an expert panel of witnesses who are joining us today.

We want to thank all of you for participating in this meeting discussion.

Winston Churchill is credited with saying a lot of things. One of my favorite Churchill quotes is, "The further back you look, the further forward you see." We are going to take a moment, if you will, to understand the history of this program and how we got to where we are today.

In the early 2000s, our Nation's energy future didn't look all that promising. Americans were consuming more and more gasoline and diesel fuel. We were incredibly relying on imported oil to fuel this growth, and that reliance was increasing. As a result, global oil prices were on the rise without any indication of slowing down, and consumers were paying more at the pump every year.

At the time, a bipartisan group of us in Congress took several steps to improve our Nation's energy future, and I would say, with the leadership of the President at the time, George W. Bush.

Among those steps, we created and expanded the Renewable Fuel Standard under the Clean Air Act. Our goals included providing new economic opportunity for our farmers while also lowering our dependence on foreign oil and reducing greenhouse gas emissions from the fuel we burn in our cars and trucks and vans.

Since the implementation of the program, we have come a long way toward achieving our goals. Economic growth in agricultural communities has expanded, and our fuels have become significantly cleaner than they were two decades ago. In fact, the Renewable Fuel Standard presents economic and energy opportunities for the people in Delaware and every other State to seize.

Like many of our colleagues on this Committee, I still support the goals of the Renewable Fuel Standard. Having said that, there have been a number of challenges when it comes to the implementation of the program, as we know.

For example, the amount of advanced renewable fuels used today in this country is far less than the 36 billion gallons that Congress and the President mandated in 2007 to be used by 2022. That shortfall is partly due to unforeseen market challenges, and it is partly due to EPA's delay in approving new fuels to enter the marketplace.

Make no mistake, advanced renewable fuels are being produced that have the potential to replace gasoline, diesel, and jet fuels on a gallon for gallon basis in today's combustion engines with no loss of performance. Many of these advanced fuels have already been approved for use in State renewable fuel programs in States like Oregon.

However, EPA has been slow to make decisions on new advanced biofuel applications and pathways for usage. At the same time, the Clean Air Act prohibits some of the advanced renewable fuels that qualify for State programs from qualifying as renewable fuel under the Federal program.

We must find better ways to allow new advanced renewable fuels to qualify for the Renewable Fuel Standard. Doing so would be good for our environment, would help refineries meet their obligations, and further support a growing domestic biofuel industry.

Another challenge in implementing the Renewable Fuel Standard is the volatility in compliance costs for refineries. Years of mismanagement under the previous Administration, coupled with the unexpected changes in both fuel supply and demand caused by the pandemic, have collectively wreaked havoc on the program's compliance market, known as the RIN market.

What is the RIN market? EPA tracks compliance with the Renewable Fuel Standard by using tradable credits, referred to as renewable identification numbers, or RINs. Refiners and importers can generate RINs either by blending biofuels into fuel or by purchasing RINs from another party through what is known as the RIN market.

The huge price swings in RIN costs, from 30 cents to almost $2 per gallon of renewable fuel in less than 2 years, have created financial uncertainty for just about everybody, especially those who are required to comply with the Renewable Fuel Standard. That, in turn, has made it extremely difficult for obligated parties to make forward thinking investments in producing cleaner fuels. We

must help reduce the volatility in compliance costs for this program to be successful.

As a recovering Governor, when exploring ways to improve Federal policies, I oftentimes look to see what is working in our States, the laboratories of democracy, and see if we can maybe replicate some of them.

Many States, like California, like Oregon, have implemented technology neutral low carbon fuel standards. These standards have successfully advanced cleaner fuel usage, kept consumer and compliance costs low, all while fostering local clean fuel investments and job creation. As we will hear today, these State programs have fuel flexibilities, long term predictability, and cost containment provisions that are not included in the Renewable Fuel Standard today, but maybe they should be.

In closing, as one of the strongest supporters of electric vehicles in the Senate, I know it is important to remember that we aren't yet in a post-liquid fuel world. We must retain our domestic capabilities to produce and refine the motor vehicle fuels that power our lives, while also ensuring that these fuels are as clean as possible in order to meet our climate goals.

We look forward to hearing from our witnesses today, but before we do that, let me turn to Senator Capito, who is off of the DL, off of the disabled list, after a very brief stay there.

Happy you are back and looking great. You are recognized for your opening statement.

OPENING STATEMENT OF HON. SHELLEY MOORE CAPITO, U.S. SENATOR FROM THE STATE OF WEST VIRGINIA

Senator CAPITO. Thank you, Mr. Chairman. It is nice to be back in the Nation's capital, so I appreciate that.

I want to thank you for calling today's hearing, and I also want to thank our witnesses for joining us here today.

The Renewable Fuel Standard, as the Chairman defined it, known as RFS, is an important topic for our Committee, but we haven't had that hearing since 2016. I think the long gap between hearings sort of speaks to the intricacies of the program, but it also is the fact that the potential fault lines between opponents, supporters, and would be reformers do not always align between one party or another.

For my part, there are a few issues I would like to cover today during this hearing: Small refinery exemptions is one, the changes to the program coming in the year 2022, and the need for accountability from EPA's Office of Air, including the need for a nominee to head it.

I would like to highlight my concern about the two actions that the EPA recently announced. First, in December, the agency proposed an all time high Renewable Volume Obligation for 2022 that does not really reflect, I don't think, market realities. I would be interested to hear what our panel has to say about that. I am concerned that this volume obligation is going to raise costs at a time when gasoline is high in and of itself, impacting American consumers and the economy.

Second, also in December, EPA also announced a proposal to deny all pending small refinery exemptions, which provide critical

relief to small refineries experiencing financial hardships that are imposed by the RFS program. This action runs counter to the congressional intent under the Clean Air Act.

EPA's proposed action will negatively impact Ergon, a small refinery located in northern West Virginia. Ergon has already won two court cases in the Fourth Circuit finding that the EPA acted in an arbitrary and capricious manner in denying its small refinery exemption petitions, but Ergon is just one of a number of small refineries around the country that had petitions pending before the EPA.

This unprecedented and drastic step to propose a blanket denial of outstanding small refinery hardship petitions is especially puzzling as we see increasing gasoline prices and several small refinery closures around the Nation, eliminating good paying jobs in some of our rural communities as well. Ultimately, this proposal will only lead to more litigation and increased uncertainty under the RFS, with American consumers bearing the costs amid already record high inflation.

I have urged EPA to reconsider its proposal to provide much needed relief for small refineries and the families and businesses being harmed by elevated fuel costs. I look forward to hearing more from our witnesses on this issue.

Next, I would like to touch on an issue that I believe many of us agree upon, and that is that our liquid fuels, and the Chairman touched on this, are still very, very important. I can tell you first hand, liquid fuel is not going away any time in my State of West Virginia.

Forcing a single technology approach, such as insisting on 100 percent electric vehicles, disregards the important fact that different communities and businesses have different needs for transportation solutions. It may be true that electric vehicle sales are slowly but surely increasing, but liquid fuel is not used exclusively in passenger vehicles. It is also important for heavy duty trucks and our airplanes, to name a few.

So, one issue I would like to hear about today is how important are liquid fuels, and do you think liquid fuels are going away anytime soon. This conversation on liquid fuel is especially important as the RFS program enters a new phase next year.

When Congress enacted the RFS, annual volumes were included for the calendar years 2006 through 2022, but after 2022, EPA has the power to determine the annual volume amounts. The Chairman pointed out that we are not even hitting the amounts that we are supposed to be hitting as it is now. EPA is expected to issue a rule to do just that sometime this year. However, I have concerns about how EPA plans to take action on this program without anyone in a Senate confirmed role in the office that handles the RFS Program.

The Office of Air and Radiation at EPA, this is the office that is in charge of air emissions and climate issues, and it handles the renewable fuel standard and many other complex regulatory programs. Yet we have been waiting for more than a year for the Administration and the President to name a nominee to that office. I have talked about this more than once in our Committee. Instead, Principal Deputy Administrator Joe Goffman has served as the

lead political official in the office, in regular communication with his former boss, the climate czar in the White House, Gina McCarthy.

No incoming Administration has waited this long to send up a nominee for this critical position since its creation. The previous record was 260 days, set by President Clinton. If EPA is deciding important actions related to the future of the RFS program, the Administration needs to send up an Office of Air and Radiation nominee who can be accountable to Congress.

With that, Mr. Chairman, I yield back my time.

Senator CARPER. Thank you very much for those comments.

Now, we are going to turn to our esteemed panel of witnesses. In a couple minutes, we will hear from them in this order: First, Cory-Ann Wind, the Clean Fuels Program Manager at the Oregon Department of Environmental Quality. Second, we will hear from Emily Skor, Chief Executive Officer of Growth Energy. Third, we are going to hear from Lucian Pugliaresi.

Lucian, would you just say your name for us?

Mr. PUGLIARESI. Lucian Pugliaresi.

Senator CARPER. All right, Lucian Pugliaresi, thank you.

Next, the President of the Energy Policy Research Foundation. Finally, last but not least, we are going to hear from LeAnn Johnson Koch, Partner at Perkins Coie.

Before our witnesses begin their testimony, I will turn it over to our colleague, Senator Merkley, to introduce one of our witnesses.

Senator Merkley, the floor is yours. Thank you.

OPENING STATEMENT OF HON. JEFF MERKLEY, U.S. SENATOR FROM THE STATE OF OREGON

Senator MERKLEY. Thank you very much, Mr. Chairman and Ranking Member Capito and fellow Committee members, for today's hearing looking at the Renewable Fuel Standard.

As we look around the world at all the visible and measurable signs of global climate change, we need to adopt cleaner forms of energy and end our dependence on carbon emitting fossil fuels. It is plain to see.

And I believe we have an incredible opportunity to reduce emissions by electrifying our cars and trucks. The investments we have made in the Infrastructure Investment and Jobs Act, as well as the ones we want to make in Build Back Better, are important steps toward that goal. But there is no doubt that sustainable liquid fuels are going to play an important role for years to come as we strive to tackle the challenge of global climate chaos.

Not all of the solutions are going to start with the Federal Government. We are going to see States innovate, and we need to learn from them. This is something we have recognized back home in Oregon, as year after year, we confront fiercer wildfires devastating our forests, historic droughts devastating our ranching and farming communities, and having a huge impact on the health of our lakes and streams, and acidifying oceans that is wreaking havoc on our sea life off the Oregon coast, and certainly on our fishing community.

Oregon has stepped up to do more through the Oregon Clean Fuels Program. Since it began almost 6 years ago, it is a resound-

ing success. Through this program, our State has reduced a significant amount of greenhouse gas emissions from transportation fuels and put us on track to meet our goal of a 10 percent reduction within the next 3 years.

I think that the success we had back home in Oregon can and ought to help inform the discussion for our Nation regarding the Federal fuels policy. Oregon stands as an example of fact that a low carbon fuel standard can work in the transportation sector, which is why I am delighted to introduce my fellow Oregonian, previously from Hawaii but now many decades in Oregon, is Cory-Ann Wind, the manager of the Oregon Clean Fuels Program.

She is a proud graduate of Oregon State University, with a degree in bioresources engineering. She has been an integral member of Oregon's Department of Environmental Quality for almost three decades, working the last 12 of them in fuels and transportation and climate policy.

As the head of the Clean Fuels Program, Ms. Wind is responsible for coordinating between the State fuel importers affected by the regulations and the clean fuels industry to ensure that everyone has the tools and technical assistance necessary to transform our fuel market.

She works to ensure that our rules and regulations align with those of neighboring States, certainly Washington and California, to help make sure that the States along the West Coast are moving in the same direction.

So I am thrilled that she is with us today through the miracle of electronics to share her experiences about what has worked in Oregon and how those successes can be implemented on a larger scale.

Thank you, Mr. Chairman.

Senator CARPER. Thank you, Senator Merkley, very much.

Now, we are going to begin our witness testimony. We are going to start off with Ms. Wind.

I am going to ask you to please proceed with your statement if you are ready. Go right ahead.

STATEMENT OF CORY-ANN WIND, OREGON CLEAN FUELS PROGRAM MANAGER, OREGON DEPARTMENT OF ENVIRONMENTAL QUALITY

Ms. WIND. Good morning, Chair Carper, Ranking Member Capito, and members of the Committee.

For the record, my name is Cory-Ann Wind, and I work for the Oregon Department of Environmental Quality as the Oregon Clean Fuels Program Manager.

Thank you for the invitation to speak to you today about the Oregon Clean Fuels Program, which is Oregon's version of the low carbon fuel standard. I would also like to thank, at this time, Senator Merkley, for the very nice introduction and for your continued leadership in addressing the climate crisis.

The Clean Fuels Program is one of Oregon's most successful statewide policies for addressing the State's contribution to global climate change. The program began in 2016, and thus far, the program's success and progress can be summarized in three distinct outcomes.

First, the companies that are producing biofuels are making those fuels more cleanly and delivering them in greater volumes to Oregon. The carbon intensity of the ethanol and biodiesel that Oregon uses has decreased, and we have seen significant increases in the blending of biodiesel and renewable diesel in recent years. Renewable forms of diesel, natural gas, propane, and electricity have all entered the Oregon market since the beginning of the program and have emerged as commercially viable and cost effective replacements of their fossil versions.

Electricity will become increasingly important as new regulations and incentives for vehicles and infrastructure are implemented. All of these fuels have played an important role in reducing about 6 million tons of lifecycle greenhouse gas emissions so far and displacing over a billion gallons of fossil fuels in Oregon.

Second, the transition from fossil fuels to biofuels and electricity is reducing tailpipe emissions in Oregon and improving the public health of Oregonians. In addition to reducing greenhouses gases, low carbon fuels also emit less carbon monoxide, nitrogen oxides, and particulate matter compared to fossil fuels.

Reducing these pollutants has saved Oregonians millions of dollars in avoided health costs over the years. And this is especially important for Oregon's historically overburdened communities that are located near transportation corridors, multimodal facilities, and distribution hubs.

And third, the program has spurred innovation and investment without impacting the price at the pump. The program has fostered a $100 million a year-plus market where investments are being made to increase the production of lower carbon fuels, spark new innovations in technology, and invest in infrastructure to deliver these fuels across the State. These investments have allowed the transition from fossil products to cleaner fuels to happen without any significant rise in retail or wholesale prices when compared to our neighboring States, even those that do not have similar fuel regulations. In fact, the program has lowered the cost of many low carbon fuels and has created a powerful financial incentive to decarbonize the transportation sector.

The Clean Fuels Program that we have created in Oregon takes the best parts of the Renewable Fuel Standard and combines it with the best parts of a low carbon fuel standard. The Renewable Fuel Standard creates the base demand for biofuels that are needed to begin the transition to lower carbon fuels, and the low carbon fuel standard ensures that the lowest of the low carbon fuels comes to Oregon.

Participants can stack the value of the credits from the Renewable Fuel Standard with the credits from the low carbon fuel standard, as both are necessary to provide the necessary incentives to fuel providers to continue to lower their carbon intensities. The market also benefits from the long term certainty from the low carbon fuel standard programs that have established targets through 2030. And Oregon is currently in a rulemaking that will extend its targets and establish standards through 2035, but we have not done this alone.

Oregon has benefited greatly from being a signatory to the Pacific Coast Collaborative. Since 2013, British Columbia, Wash-

ington, Oregon, and California have worked together to harmonize best practices for policy alignment, program design, and implementation to create the largest market for cleaner, low carbon fuels on the West Coast.

This collaboration has grown to other States that are now also looking for smart strategies to reduce transportation emissions, ones that can build off of strong Federal support of the agriculture and biofuels industry, zero emission vehicle standards, and investments in electric vehicle charging and alternative vehicle fueling infrastructure.

That concludes my testimony for today. I am happy to take any questions that you might have. Thank you again for the invitation to be here.

[The prepared statement of Ms. Wind follows:]

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Testimony before the U.S. Senate Committee on Environment and Public Works

"The Environmental Protection Agency's Renewable Fuel Standard Program: Challenges and Opportunities"

Cory-Ann Wind, Oregon Clean Fuels Program Manager

Oregon Department of Environmental Quality

February 16, 2022

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Second, the transition from fossil fuels to biofuels and electricity is reducing tailpipe pollution and improving the public health of Oregonians. In addition to reducing greenhouses gases, low-carbon fuels also emit less carbon monoxide, nitrogen oxides, and particulate matter compared to fossil fuels. Reducing these pollutants has saved Oregonians millions of dollars in avoided health costs over the years. This is especially important for Oregon's historically overburdened communities that are located near major transportation corridors, multimodal facilities, and distribution hubs.

And third, the program has spurred innovation and investments without impacting the price at the pump. The program has fostered a $100-million-plus-a-year market where investments are being made

to increase the production of lower-carbon fuels, spark new innovations in technology, and invest in infrastructure to deliver these fuels across the state. These investments have allowed the transition from fossil products to cleaner fuels to happen without any significant rise in retail or wholesale fuel prices when compared to our neighboring states; even those that have not had similar fuel regulations. In fact, the program has lowered the cost of many low-carbon fuels and has created a powerful financial incentive to decarbonize the transportation sector.

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Senate Committee on Environment and Public Works
Hearing Entitled, "*The Environmental Protection Agency's Renewable Fuel Standard: Challenges and Opportunities*"
March 16, 2022
Responses for the Record for Cory-Ann Wind

All responses from Cory-Ann Wind to the questions posed by Senator Carper and Ranking Member Capito are presented in blue italicized font.

Senator Carper:

1. Despite decades of oil and gasoline price spikes in the United States, the American people still have very little choice at the pump when it comes to the type of fuel they can use to fuel their vehicle. Our economy continues to be tied to the price of oil, which as we see too well today, is impacted by foreign events and the world economy. One of the goals of the Renewable Fuel Standard (RFS) is to help transition the United States away from oil and toward a domestic supply of fuel for our transportation sector.

    a. Please discuss how Oregon's Clean Fuels Program has helped move Oregon off oil-based transportation fuels, beyond the federal RFS program. How much traditional gasoline and diesel fuel has been replaced with clean, domestic fuel as a result of the Clean Fuels Program? *The Clean Fuels Program incentivizes transportation fuels that are lower carbon than traditional gasoline and diesel which leads to cleaner biofuels coming to Oregon and the rates of blending biofuels that are higher than most states. Through the second quarter of 2021, the Clean Fuels Program has displaced over a billion gallons of fossil gasoline and diesel with ethanol, biodiesel, renewable diesel, fossil and renewable propane, fossil and renewable natural gas, and electricity. Some of the biodiesel and renewable diesel is produced overseas but the majority is produced domestically.*

    b. In your opinion, does the federal RFS program and state low carbon fuel standard programs, such as the Oregon's Clean Fuel Program, help reduce our nation's dependence on foreign oil? *Yes, both programs help reduce our nation's dependence on oil.*

    c. In tracking fuel prices, have you found the largest driver of costs for consumers in terms of gasoline and diesel prices at the pump comes from the price of oil and not from environmental programs? If yes, please explain further. *My understanding is that the prices of gasoline and diesel generally track the price of crude oil. While some may believe that state regulations significantly impact on those prices, data show that it is not always the case that states with such programs have higher prices. As presented in the recent Clean Fuels Program review (see pages 28-30), EIA data show that both Washington and Idaho, two neighboring states that have not had low carbon fuel standards through 2021,*

had similar or higher retail and wholesale fuel prices compared to Oregon since 2016 when the Clean Fuels Program began.

d. In your opinion, would a more flexible low carbon fuel program at the federal level, similar to Oregon's Clean Fuel Program, help reduce our nation's dependence on foreign oil and as a result help mitigate consumer cost spikes when global oil prices spike? *In my opinion, an effective fuels program would encourage greenhouse gas reductions for any fuel that could be used for transportation. This could either be at the federal or state level or both. Since many of these lower carbon fuels are being made domestically, it can reduce our reliance on oil and the impact of the volatile global crude oil market.*

2. Similar to the RFS program's compliance credit system, regulated parties in Oregon's Clean Fuels Program comply with the statewide standard by retiring enough compliance credits to cover any deficits they hold, which creates a demand and supply of program credits. Obligated parties may reduce the carbon intensity rating of their fuels, generate their own credits, buy credits from other market participants, or apply credits banked in earlier years.

   a. Please describe in detail how the Clean Fuels Program allows for the use of bankable credits for future compliance. *The Clean Fuels Program is designed for its carbon intensity standards to be increasingly stringent each year. Since targets are easier to comply with earlier in the program, participants can generate more credits than they need for compliance in those early years and bank them for future use. This promotes activities and actions to expand the supply of low carbon fuels in the state early on, which will help with increasing the use of those fuels in future years, and allows regulated parties to have a bank of credits for future compliance in the future.*

   b. Please describe the Clean Fuels Program's end-of-year credit market system and how that credit market helps address short-term credit supply shortfalls. *The Clean Fuels Program employs a Credit Clearance Market that creates a clear path for regulated parties to come into compliance with the clean fuel standards in the event that they are short in the number of credits they need to comply. The CCM strengthens the program by setting the maximum compliance cost for the program, reducing the possibility of credit price spikes, and maintaining the incentive to invest in low carbon fuel production and distribution. The CCM also creates a clear maximum price for selling credits at the end of a compliance period, and thus caps the cost of complying with the program.*

   The CCM works this way: Each year, DEQ asks the registered parties if they wish to pledge credits into the CCM. Regulated parties are required to submit their annual compliance report to DEQ by April 30th. If they are short credits, they

must notify DEQ and then they have a month to purchase credits from the parties who pledged credits into the CCM at a maximum price that is $200 in 2018 dollars and adjusted annually for inflation. For 2022, the CCM price is $230.43. The regulated parties are required to purchase at least their pro rata share of pledged credits to be incompliance if there are not enough credits pledged into the CCM. Any remaining deficits are carried over to the next year at a 5% penalty.

3. During the hearing, you mentioned that Oregon's Clean Fuels Program requires regular fuel supply monitoring and periodic fuel supply forecasting in an attempt to foresee potential fuel supply challenges.

    a. Please describe in detail how the Oregon Department of Environmental Quality (DEQ), the regulator of the Clean Fuels Program, monitors the state's fuel supply. *The Oregon Department of Administrative Services, Office of Economic Analysis is required, with substantial assistance from DEQ, to produce annually a forecast regarding deficits and credits owing to fossil and alternative fuel consumption, as well as the availability of fossil and alternative fuels in Oregon. In particular, the forecast is to determine whether fuel supply will be sufficient to generate alternative fuel (ethanol, electricity, and diesel substitutes - including biodiesel, renewable diesel, natural gas, and propane) credits to meet the scheduled applicable low carbon fuel standards for the compliance period. The forecast report is required to include an assessment of banked deficits and credits at the beginning of the compliance period. The Clean Fuels Forecast is issued annually on October 1st.*

    b. What authority does DEQ have to make adjustments to the program in the event of a fuel supply shortage or credit or fuel market disruptions? *If the Clean Fuels Forecast projects that the amount of credits that will be available during the forecast compliance period will be less than 100 percent of the credits projected to be necessary for regulated parties to comply, then DEQ shall issue an order declaring a forecast deferral which includes the duration of the forecast deferral, the types of fuel to which the forecast deferral applies; and which method DEQ has selected for deferring compliance with the clean fuel standard during the forecasted deferral.*

    c. Please provide details of any cost containment mechanisms DEQ is able to utilize to address fuel supply shortages or compliance credit shortfalls. *In addition to the CCM and forecast deferral, the Clean Fuels Program also has a provision under Oregon Administrative Rules 340-253-1030(4) that allows small deficits, defined as less than 5% of a regulated party's total deficits, to be carried over to the following compliance period without penalty. Additionally, the Clean Fuels Program can issue an emergency deferral due to a fuel shortage, a credit market disruption, or abnormal credit market behavior under Oregon Administration Rules 340-253-2000.*

4. What other elements of Oregon's Clean Fuel Program that were not discussed at the hearing should we consider applying to the federal RFS program to increase the flexibility and certainty for stakeholders and encourage greater deployment of more sustainable fuels? *These items were already shared at the hearing and in #1.d above.*

5. Oregon's Clean Fuels Program bases its incentives on a lifecycle analysis of each fuel pathway – a formalized description of the full procurement, production, and distribution stages of bringing the fuel into the transport market in Oregon.

    a. Please describe in detail the modeling used by the Oregon Clean Fuels Program to assess the carbon intensity of various fuel pathways. Is this modeling based on any existing life-cycle models? *The Clean Fuels Program uses a modified version of the GREET model that was developed and maintained by the Argonne National Laboratory to conduct its lifecycle analysis.*

    b. How did Oregon determine which life-cycle model would be used by the Clean Fuels Program? *The GREET model was chosen during the stakeholder process to design the Clean Fuels Program.*

    c. Does Oregon's Clean Fuels Program utilize or require any third-party independent validation of information used in carbon intensity calculations? *Beginning in 2022, the Clean Fuels Program will require third party verification of annual fuel pathway reports if the number of credits from that pathway exceeds 6,000 credits per year.*

    d. How do Oregon's carbon intensity scores for fuel pathways interact and/or reflect carbon intensity assessment processes in other states, like California? *DEQ designed the Clean Fuels Program to closely align with California's process to approve fuel pathways. If a producer receives a carbon intensity score in California, that producer can submit that approval and supporting documentation to DEQ for approval in the Clean Fuels Program with an adjustment for transportation mode and distance.*

6. Oregon is part of the Pacific Coast Collaborative, the agreement between California, Oregon, Washington, and British Columbia, to take action on climate change, including creating a regional low carbon fuel market. California and British Columbia adopted clean fuels policies in 2010; Oregon followed in 2016; and Washington is currently working to implement the state's clean fuels program.

    a. What are some of the benefits of the West Coast's collaborative approach? *Since the low carbon fuel standard is a market-based approach, it is important that the regulation of the regional transportation fuels market, aka the entire west coast, be harmonized to send consistent signals. Most importantly, harmonization*

should occur in the way lifecycle greenhouse gas emissions are calculated and the development of cost containment mechanisms.

b. What are some of the challenges associated with this regional approach? How is Oregon navigating these challenges? *Each state has its own set of directions given to them by their legislatures and governing bodies (i.e. boards or commissions) that must be considered when attempting to develop a regional policy. That is why we aim for the harmonization of critical elements of the policy rather than adopting an identical program from state to state. Oregon has adopted several provisions that are different than California and British Columbia based on direction from the Oregon Legislature and the Oregon Environmental Quality Commission.*

c. How can the Pacific Coast Collaborative serve as an example for other regions where states are considering low carbon fuels policies? *The Pacific Coast Collaborative is an excellent example of how states can coordinate on policy that is best suited for a regional approach. It creates opportunities for the participating jurisdictions to learn from each other, pool their resources, and prioritize efforts to keep up with the latest science and technology innovations in the transportation fuels market.*

7. In the recently released draft regulatory impact statement for the Renewable Fuel Standard (RFS) program's proposed renewable volume obligations for 2022, the Environmental Protection Agency (EPA) stated that the Agency "cannot ensure that parties registering to generate RINs will be able to demonstrate that the electricity is not claimed by multiple parties attempting to demonstrate transportation use." However, California and Oregon have for years allowed low carbon electricity to participated in each state's low carbon fuel program and found ways to eliminate the concerns raised by EPA. For example, Oregon has been allowing EV charging station owner-operators to create Clean Fuel Standard credits and that the State has rules in place to ensure that other credit generators, like utilities or station site hosts, do not also generate credits from the same EV charging event.

a. Please provide the committee additional details on how Oregon prevents double counting of EV charging events in its Clean Fuels Program. *Each piece of fuel supply equipment (or charger) is required to be registered in the CFP, identified by location and serial number. Each quarter, the owner of the charger reports how much electricity is dispensed from each FSE and if a second entity attempts to report for the same FSE, the report is rejected.*

b. Would Oregon's thoughtful treatment of this issue, and possibly other state actions such as California, serve as a good model for EPA as they move forward to propose federal electric renewable identification numbers, or e-RINs, rules that

prevent double counting? *Our system of reporting has been very effective in preventing double counting of electricity for credit generation in the CFP.*

8. People living in areas with heavy vehicle traffic are more likely to be minority and low-income populations and are disproportionately impacted by toxics and particulate matter emitted from internal combustion engines. How does Oregon's Clean Fuels program help address the environmental justice impacts of air pollution from vehicle emissions? *While the primary goal of the Clean Fuels Program is to reduce greenhouse gas emissions, it also reduces traditional tailpipe emissions that cause negative health effects. Replacing fossil fuels like gasoline and diesel with lower carbon fuels like biofuels and electricity reduce the impact to overburdened communities especially those that are located near transportation corridors.*

Ranking Member Capito:

1. How important are liquid fuels?

    a. Do you think liquid fuels are going away anytime soon? *Even with the most aggressive zero emission vehicle regulations (100% of new vehicle sales in 2035 being ZEV), there will be liquid fuels for decades. Therefore, it is imperative to find and incentivize low-carbon solutions for gasoline and diesel.*

2. The 117th Congress is considering several energy tax provisions. Among these are enhanced tax credits for various kinds of alternative fuels and advanced biofuels, including for sustainable aviation fuel. Do you have any concerns that more favorable tax treatment for subcategories like sustainable aviation fuel may have unintended consequences for other types of transportation fuels, such as biodiesel and renewable diesel, that compete for the same input feedstocks?

    a. What potential implications do these sorts of preferential policies have for supply and demand of other biofuels, prices for consumers buying these fuels, as well as the broader transportation fuel sector's ability to meet requirements under the RFS? *Not only do they compete for the same feedstock, but they are commonly produced at the same facility (i.e. sustainable aviation fuel can be made using the same process as renewable diesel). Any mechanism that targets a specific fuel or feedstock or technology has the potential for unintended consequences.*

Senator CARPER. We are delighted that you are here. Thank you so much. I like to say, find out what works, do more of that. Sometimes those States come up with some pretty good ideas that we would benefit from. Thank you very much for your testimony.

Next, we are going to hear from Ms. Skor.

Ms. Skor, please proceed. Thanks so much for joining us. Nice to see you.

STATEMENT OF EMILY SKOR,
CHIEF EXECUTIVE OFFICER, GROWTH ENERGY

Ms. SKOR. Nice to see you, Chairman Carper, Ranking Member Capito, and members of the Committee. Thank you for the opportunity to testify today.

I am Emily Skor, CEO of Growth Energy, the world's largest biofuel trade association.

The RFS remains the Nation's most successful clean energy policy, yet its full potential as a climate solution remains untapped. For the past 8 years, a lack of accountability and failure to comply with the law has slowed progress in carbon reductions.

But today, as Congress looks to immediately reduce the carbon intensity of our Nation's transportation fleet, it is imperative that biofuels like ethanol, the most affordable and abundant source of low carbon, high octane fuel on the planet, are part of our transportation mix now and into the future.

Let me be clear: There is no path toward net zero emissions by 2050 without biofuels. Ninety-eight percent of the cars on the road today use liquid fuels, and EIA projects that gasoline or flex fuel powered vehicles will dominate new vehicle sales through 2050.

We can achieve progress in carbon reductions with today's infrastructure, today's vehicles, and a home grown supply chain through a robust and binding Renewable Fuel Standard and acceleration toward nationwide, year round use of lower cost biofuels like E15.

To date, the RFS has reduced almost 1 billion metric tons of greenhouse gas emissions. Expanded use of low carbon biofuel cuts emissions in air pollution, drives energy innovation and economic growth, creates biomanufacturing jobs, and lowers gas prices for American drivers.

But since 2013, the RFS has consistently been undermined through the abuse of waivers, small refinery exemptions, and compliance deadline extensions. Most of these administrative actions have been to appease the unfounded claims of a select few looking to subvert the RFS, slowing progress in carbon reductions.

EPA's recent proposals, delayed as they are, right some of these wrongs. They include the required 15 billion gallons of conventional biofuel in 2022, a long overdue remedy for EPA's unlawful 2016 general waiver, and an end to the abuse of small refinery exemptions.

Despite these positives, EPA takes a major step backward by seeking to reduce the 2020 blending obligations finalized 2 years ago. This retroactive change exceeds the agency's authority and creates market disruption and uncertainty. EPA needs to fix and finalize the proposals as soon as possible.

Looking forward, to achieve our shared clean energy goals, we need year round access to higher blends of ethanol, like E15. Na-

tionwide, E15 would slash CO_2 emissions by more than 70 million tons, support more than 180,000 new jobs, and save consumers more than $12 billion in annual fuel costs.

Unfortunately, refiners successfully sued to prevent E15 from being sold in the summer throughout much of the country. Not only have they deprived consumers of a lower cost fuel, they eliminated an easy path for their own RFS compliance. Without immediate action, consumers will lose access to their most affordable fueling option on June 1st, when Americans drive the most. Congress or EPA must restore market access so drivers can save up to 10 cents per gallon every time they fuel up with E15.

In addition to reducing emissions in light duty vehicles, biofuels are poised to play a greater role in decarbonizing other forms of transportation, and biorefineries are already deploying carbon capture and wind and solar energy and incentivizing sustainable farming practices, all to drive further innovation and further reductions in our carbon intensity. We see promise in new and emerging low carbon fuel markets in hard to electrify sectors, like aviation, marine, and heavy duty vehicles.

To lead our Nation through a clean energy transition, we must have a healthy and thriving biofuel industry. We must have a strong and growing RFS. We must move toward E15 as the Nation's standard fuel.

Don't be fooled: The RFS does not harm refiners. Three Administrations and the courts have affirmed this. Claims to the contrary are just a smokescreen to divert attention away from clean, affordable, American energy. Undermining the RFS and delaying the rollout of E15 means increasing gas prices for American consumers, period. Yes, prices are driven by the price of crude, not the cost of the RFS.

America's farmers and biofuel producers are ready to work with the Administration and Congress to restore E15 and put the RFS back on track.

Thank you, and I look forward to your questions.

[The prepared statement of Ms. Skor follows:]

Testimony before the U.S. Senate Committee on Environment and Public Works

"The Environmental Protection Agency's Renewable Fuel Standard Program: Challenges and Opportunities"

Emily Skor, CEO
Growth Energy

February 16, 2022

Chairman Carper, Ranking Member Capito, and Members of the Committee:

Thank you for the opportunity to testify today on how the Renewable Fuel Standard helps our country decarbonize our national transportation fleet by growing the use of low-cost, low-carbon biofuels like ethanol. My name is Emily Skor, and I am the CEO of Growth Energy, the world's largest ethanol trade association.

Growth Energy represents over half of all U.S. ethanol production, including 89 producer plants, 96 innovative businesses that support biofuels production, and tens of thousands of ethanol supporters around the country. The United States is home to 210 biorefineries across 27 states that have the capacity to produce more than 17 billion gallons of low-carbon, renewable fuel.

Ethanol is an incredible American success story, driving significant economic growth and investment in sustainable renewable energy, while supporting more than 350,000 jobs nationwide and contributing to a strong rural economy. We are committed to bringing environmentally friendly biofuels into our nation's transportation fuel supply, helping our country diversify our energy portfolio, growing the number of clean energy jobs, sustaining family farms and rural communities, and driving down fuel costs at the pump for consumers.

As this committee and Congress look for ways to reduce the carbon intensity (CI) of America's transportation sector, policymakers must recognize ethanol's role in reducing emissions for light duty vehicles, as well as its potential to do the same in American aviation and shipping.

At a time where energy costs continue to rise, plant-based renewable fuels like ethanol remain the single most affordable and abundant source of low-carbon motor fuel on the planet, delivering on a new wave of demand for clean energy—on the ground and in the sky, at home and abroad, in today's vehicles and tomorrow's.

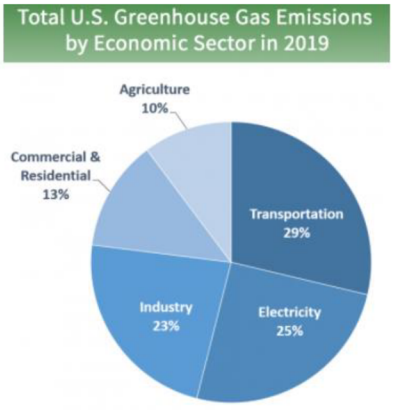
Research shows that there is no path to net-zero emissions by 2050 without biofuels. Even accounting for the projected growth of electric vehicles, the Energy Information Administration (EIA) indicates that the vast majority of cars on the road through 2050 will run on liquid fuels. Biofuels like ethanol are affordable and available for use in our current auto fleet and will help ensure lower emissions in legacy vehicles on the road for decades to come. Put simply, America cannot decarbonize the transportation sector without homegrown biofuels.

My comments today will focus on how America's ethanol industry is leading the way in producing renewable energy, driving new economic activity, and providing environmental benefits on behalf of the nation. With consistent, predictable policy and market signals, America's ethanol industry can realize its full ability to decarbonize American transportation. Specifically, I will explore the following areas:

- Why low-carbon, plant-based, liquid biofuels like ethanol are an essential solution to meet our climate goals;
- How a strong and growing Renewable Fuel Standard (RFS) will continue to cut carbon emissions from the transportation sector;
- How higher-level ethanol blends like E15 can drive down emissions and lower consumer fuel costs;
- How hard-to-electrify sectors of transportation—like aviation, heavy duty shipping, and marine transport—represent a vast potential new market for America's biofuel producers; and
- How a properly crafted clean fuel standard and higher-octane levels in light duty vehicles can drive further carbon emission reductions.

Biofuels: An Essential Solution to Meet Climate Goals

Figure 1: U.S. GHG Emissions by Sector



Source: EPA

This past year our nation has increased its focus on achieving long-term, carbon reduction goals. The Biden Administration has pledged to reduce greenhouse gas (GHG) emissions by 50-52% by 2030 and make the United States carbon neutral by 2050. There is no one-size-fits-all path toward decarbonization. Meeting this challenge will require a broad array of solutions, and renewable, plant-based biofuels like ethanol are readily available today to accelerate our transition to a healthier, net-zero emission, 100% renewable energy future.

In 2019, the transportation sector accounted for 29% of all greenhouse gas emissions in the United States, the highest of any major economic sector[1]. Lowering carbon emissions in transportation is paramount to meeting the Biden Administration's climate goals. Biofuels offer an immediate solution.

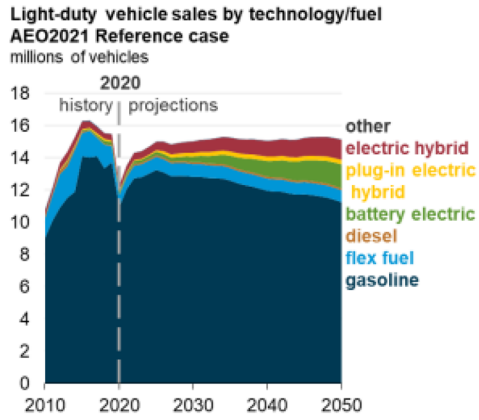
Plant-based ethanol is low-carbon and can be used in our current auto fleet. It is also affordable, keeping fuel prices lower for all drivers in all communities. Drivers today can choose fuel blended

[1] "Sources of Greenhouse Gas Emissions," U.S. Environmental Protection Agency. https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions

with ten-percent ethanol (E10), fifteen-percent ethanol (E15), or up to eighty-five percent ethanol (E85).

A recent January 2021 study by Environmental Health & Engineering, Inc., found that ethanol reduces GHGs by 46% compared to traditional gasoline[2]. Corn ethanol's relative carbon benefits could reach up to 70% by the end of 2022, according to the U.S. Department of Agriculture (USDA)[3]. Biofuel use between 2008 and 2020 has already resulted in cumulative reductions of almost 1 billion metric tons of carbon-dioxide equivalent GHG emissions[4]. Additionally, a nationwide transition from E10 to E15 would lower GHG emissions by 17.62 million tons annually, the equivalent of removing 3.85 million vehicles from the road[5].

Figure 2: Light-Duty Vehicle Sales by Fuel Type



Source: U.S. Energy Information Administration

Recent data from the EIA indicates that while we will see dramatic growth in the number of electric vehicles, vehicles that run on liquid fuels will dominate the light duty vehicle landscape for decades. EIA's 2021 Annual Energy Outlook stated that gasoline and flex fuel vehicles will account for 79% of vehicles sales in 2050, down from 95% today, as referenced in Figure 2[6]. Moreover, EIA projects in its 2021 International Energy Outlook that the number of conventional light duty vehicles worldwide—those which operate on liquid fuels—will not peak until 2038[7].

While electric vehicles have a role to play in our overall portfolio of options for reducing carbon emissions, the fact remains that internal combustion engines will continue to be prominently used for decades. No single solution will enable our transportation sector to achieve net-zero carbon emissions by 2050, and we will need every tool in our toolbox. We will see increased efforts towards electrification

[2] "Carbon Intensity of corn ethanol in the United States: State of the science," *Environmental Health & Engineering, Inc.* Melissa Scully, Gregory Norris, Tania Alarcon Falconi, and David MacIntosh. March 2021. https://iopscience.iop.org/article/10.1088/1748-9326/abde08

[3] "The greenhouse gas benefits of corn ethanol—assessing recent evidence," *Biofuels*. Jan Lewandrowski, Jeffrey Rosenfeld, Diana Pape, Tommy Hendrickson, Kirsten Jaglo, Katrin Moffroid (2020). 11:3, 361-375, DOI: 10.1080/17597269.2018.1546488.

[4] "Annual Energy Outlook 2021," Energy Information Administration. February 2021. https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

[5] "EIA projects global conventional vehicle fleet will peak in 2038," Energy Information Administration. October 2021. https://www.eia.gov/todayinenergy/detail.php?id=50096&src=email

[6] "Annual Energy Outlook 2021," Energy Information Administration. https://www.eia.gov/outlooks/aeo/pdf/AEO_Narrative_2021.pdf

[7] "EIA projects global conventional vehicle fleet will peak in 2038," Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=50096&src=email

and vehicle efficiency, but we will also need more biofuels like ethanol, which have the potential to do even more to reduce the carbon intensity of transportation with the right combination of policy and marketplace certainty. An analysis by the Rhodium Group released in January 2021 underscores this reality, finding that biofuels are a mainstay for any climate strategy looking to attain net-zero emissions by 2050[8].

A Strong and Growing RFS Will Continue to Cut Carbon Emissions from the Transportation Sector

The RFS is one of the nation's most successful renewable energy policies for reducing GHGs and providing a steady market for U.S. grain. This policy is the bedrock for the modern biofuels industry, providing a stable platform for ethanol producers to expand our nation's supply of renewable, homegrown, low-carbon liquid fuels. Given the importance of this policy, we are greatly concerned about recent proposals by the Environmental Protection Agency (EPA) on 2020 through 2022 Renewable Volume Obligations (RVOs) that, despite having some positive aspects, would, if finalized, undercut the RFS, directly contradict President Biden's strong commitment to lower-carbon emissions, and leave us further reliant on fossil fuels.

EPA's proposed RVOs for 2020-2022 show some progress but also have some significant flaws. We are pleased to see the proposal concludes that a non-advanced volume of 15 billion gallons of renewable fuel is readily achievable, includes a long overdue remedy of the unlawful 2016 general waiver, and appropriately provides needed transparency into decisions around the small refinery exemption (SRE) program. We have strong concerns, however, that certain aspects of this proposal would seriously damage the RFS program and violate EPA's legal duties, by, for example, substantially undervaluing the benefits of conventional ethanol for combatting climate change, relieving obligated parties of their failure to meet their 2020 obligations (even after accounting for the actual levels of fuel use and SREs in 2020), and nullifying the program for 2021.

In addition, because EPA has repeatedly failed to issue timely blending requirements, the agency often defaults to setting the requirements after the fact, at the actual level of renewable fuel use, which undermines the RFS' market-forcing intent to blend more renewable fuel into our fuel supply each year. The 2020-2022 RVO proposal is no exception.

The Biden Administration simply cannot meet its climate goals without a strong and growing RFS. In our comments to EPA, we urge the agency to carefully reconsider key aspects of its proposal to ensure that they accord with the goals Congress set for the RFS program and the limits Congress placed on EPA's authority. Growth Energy also urges EPA to finalize this rulemaking expeditiously.

Positive Components of the 2020-2022 RVO Proposal and Proposed SRE Denials

1. **For the first time ever, EPA appears to provide a true, unencumbered 15 billion gallons of conventional biofuel blending.** Despite annual RVOs setting the implied conventional

[8]"Closing the Transportation Emissions Gap with Clean Fuels," Rhodium Group. January 2021. https://rhg.com/research/closing-the-transportation-emissions-gap-with-clean-fuels/

biofuel blending requirement at 15 billion gallons each year since 2015, administrative negligence has resulted in this volume never actually being realized. Illegal delays, illegal interpretations of the RFS law overturned by the courts, and egregious abuse of the SRE program, also overturned by the courts, have resulted in six consecutive years (2015-2021) of RFS blending requirements that were lower than they should have been, contradicting congressional intent for a strong RFS each year. We are encouraged that EPA's proposal for the first time sets a conventional requirement that closes unjustified loopholes that drive blending lower and carbon emissions higher, and that, if properly implemented, should result in 15 billion gallons of actual blending for the first time.

2. **EPA is finally responding to a court order and re-instating 500 million RINs that it illegally waived.** After almost five years since the D.C. Circuit unanimously struck down an illegal interpretation from EPA that redefined supply as demand, EPA plans to release 250 million of these RINs in 2022 and 250 million more in 2023.

3. **Using a unanimous ruling from the 10th Circuit, EPA is proposing to deny 65 outstanding SREs as well as provide additional transparency for SRE decisions.** I will touch more on SREs later in my testimony.

Needed Fixes to the 2020-2022 RVO Proposal

1. **EPA must adopt a framework for performing a reset that is faithful to the RFS Program's statutory structure and purpose**. In proposing standards for 2020, 2021, and 2022, EPA invokes its reset authority for the first time. Contrary to EPA's proposed approach, the reset is not a valid mechanism to re-open previously finalized standards, to override congressional directives and priorities, or to engage in an amorphous balancing of factors as it sees fit. Rather, Congress intended the reset mechanism to be a targeted, prospective correction for the specific conditions that triggered the reset. In conducting a reset, EPA must still establish volume requirements that, first and foremost, further Congress's market-forcing policies and objectives, to the extent that a volume of renewable fuel use is feasible and will not cause important and severe harm of the type that would trigger another waiver. Further, EPA must always take into account the best available science when performing a reset.

2. **EPA should prioritize climate change impacts and must incorporate the best available science in its analysis.** Reducing GHG emissions from the transportation sector is a core congressional objective of the RFS—indeed the RFS is the only Clean Air Act program explicitly aimed at reducing GHG emissions—and thus, it deserves special emphasis. Congressional intent for RFS implementation to be market-forcing and achieve the fullest measure of available GHG reductions from transportation fuel aligns with EPA's and the Administration's stated climate goals and efforts to decarbonize the transportation sector. Thus, it is imperative EPA update its lifecycle GHG emissions analysis for conventional corn ethanol using the best currently available science. EPA has not updated its lifecycle analysis since 2010 and thus fails to account for improvements in GHG lifecycle emission modeling and the industry's considerable innovations and investments in sustainability in the past decade.

3. **EPA's proposed modification of the 2020 standards undermines the RFS program, contradicts the Clean Air Act, and is irrational.** EPA proposes to retroactively reduce the 2020 volumes from a final total renewable fuel of 20.09 billion gallons down to 17.13 billion gallons. For implied conventional biofuel, the volume is lowered from 15 billion gallons down to 12.5 billion gallons, nearly 150 million gallons lower than actual ethanol consumption for the year. This is plainly unlawful. EPA has no power to relieve obligated parties of their noncompliance simply because they did not comply. Congress designed the RFS program to force the market to use increasing volumes of renewable fuel each year, and the threat of penalties for noncompliance is the mechanism by which the program implements this design. EPA's proposed retroactive absolution creates a perverse incentive: obligated parties will have no reason to bother complying with RFS standards. When they fail, EPA will absolve them, and the more they fail, the more likely EPA is to save them. Congress did not grant EPA such a counterproductive power. Certainly, the reset provision does not grant such power.

4. **EPA should retain the standard equation as revised in the 2020 rule.** Even if EPA adopts the standards and findings of its separately proposed denial of pending SRE petitions (as it should), EPA should still retain the standard equation used for establishing individual refiners' annual blending standards as revised by the original 2020 rule, so that the equation adjusts for projected SREs. That would enable EPA to set future standards that are rationally and reasonably calculated to ensure that the applicable volume requirements are met, as EPA is statutorily required to do.

5. **It is imperative that renewable fuel producers have flexibility to use biointermediates in fuel production in order to lower costs and drive innovation.** EPA should ensure that the final biointermediates regulations facilitate use of biointermediates, afford needed flexibility to producers, and are not unduly burdensome on potential biointermediates or renewable fuel producers. Clarity on biointermediates is essential for continued industry innovation and the production of sustainable aviation fuel and other renewable fuels.

6. **EPA should act expeditiously to approve the numerous pending registration applications for simultaneous production of starch and cellulosic ethanol from corn kernel feedstock.** EPA should expedite pathway approvals for carbon capture, utilization, and storage, and approve the pending petition to allow biodiesel and renewable diesel facilities to use corn oil produced from corn wet mills as feedstock.

Small Refinery Exemptions

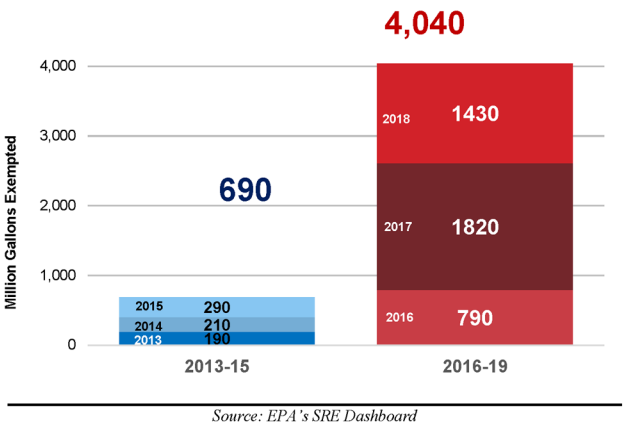
Despite the demonstrable economic, environmental, and energy security success of the RFS, the previous EPA repeatedly granted oil refiners an unprecedented number of SREs, allowing them to avoid their obligations to blend biofuels into our national fuel supply.

EPA's authority to grant SREs was included under the Clean Air Act to provide small refineries (those with a daily input capacity of less than 75,000 barrels of crude oil) with a temporary avenue to avoid blending obligations, provided the refinery demonstrate that compliance results in disproportionate economic hardship. But in the previous administration, the number of SREs

increased six-fold with no transparency into the process or explanation as to which refineries received an exemption and why.

As shown in Figure 3, EPA granted 85 SREs over four years, which cost the ethanol industry four billion gallons of lost biofuel demand. Many of the SREs went to some of the largest, most profitable oil companies in the world.

Figure 3: SREs by Administration



Source: EPA's SRE Dashboard

In January 2020, the 10th Circuit Court of Appeals issued a unanimous decision that invalidated SREs granted by EPA to three refineries for the 2016 and 2017 compliance years on three grounds. First, the court held that EPA could grant SRE "extensions" only to those refineries who had received SREs in all prior years. Second, the court held that it was improper for EPA to find disproportionate economic hardship on bases other than alleged hardship caused solely by compliance with the RFS. Third, the court held that EPA failed to explain why it deviated from its previous position that refineries recoup their costs of compliance through downstream pricing. The refineries successfully petitioned the U.S. Supreme Court for review of the decision solely on the first, "extension" holding of the 10th Circuit, which the Supreme Court overturned.

The Biden Administration EPA has stated that its proposed denial of the 65 pending SRE petitions is informed by the remaining portions of the 10th Circuit's opinion, in particular, that SREs must be based solely on hardship caused by compliance with the RFS[9]. And since at least 2015, EPA has consistently found that obligated parties—big and small—do not face disproportionate economic hardships from compliance with the RFS. EPA's proposed decision on SREs will strengthen the RFS program, reduce the nation's emission of greenhouse gases, and support renewable, American-grown biofuels. Congress intended the RFS program to increase the nation's

[9] "Proposed RFS Small Refinery Exemption Decision." U.S. Environmental Protection Agency. December 2021. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1013KMM.pdf

consumption of renewable fuel and move the United States toward greater energy independence and security. However, the Trump Administration EPA's previous policies regarding extensions of exemptions for small refiners and refineries (together, "small refineries") undermined congressional intent and continues to jeopardize the RFS program as a whole. EPA's Proposed RFS Small Refinery Exemption Decision (EPA-420-D-21-001) (the "Proposed Decision") is a step forward in righting EPA's previous wrongs[10]. Not only will denying the 65 pending petitions for SREs increase access to renewable fuel, but such action also is necessary to bring EPA's policies in line with federal law and EPA's own long-held findings that RFS program compliance does not disproportionally harm small refineries.

EPA should also deny all other pending SRE petitions (and all future petitions) that fail to meet the criteria set forth in the Proposed Decision, including the 36 challenged 2018 SRE petitions that the U.S. Court of Appeals for the D.C. Circuit remanded to EPA for further consideration on December 8, 2021.[11]

EPA should also adopt the proposed approach to confidential business information in its RVO proposal. We support EPA's proposal not to treat as confidential basic information relating to SRE petitions and SRE decisions for purposes of the Freedom of Information Act. EPA thwarts essential oversight and engages in secret national lawmaking when it conceals its SRE decisions. EPA's proposal accords with recent case law, Justice Department guidance, and good government practices. EPA has made similar proposals in the past; now is the time to finally adopt this important policy change.

RIN Prices

Renewable Identification Numbers (RINs) were included in the RFS to add flexibility to the compliance mechanism of the RFS. Obligated parties have the option to either blend biofuels and generate RINs or purchase RINs to meet their obligations under the RFS.

We are aware that some refiners who have chosen to purchase RINS in lieu of blending renewable fuels are seeking a waiver for their blending obligations, citing economic hardship as a result of high RIN prices. Some refineries claim this causes higher gasoline prices.

To be clear, there is no relationship between RIN prices and refinery profits, as EPA has repeatedly stated:

> "We do not believe that the price paid for RINs is a valid indicator of the economic impact of the RFS program on these entities [refiners], since a narrow focus on RIN price ignores the ability for these parties to recover the cost of RINs from the sale of their petroleum products[12]."

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[10] "Proposed RFS Small Refinery Exemption Decision." U.S. Environmental Protection Agency. December 2021. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1013KMM.pdf

[11] Per curiam order, *Sinclair Wyoming Refinery v. EPA*, Case No. 19-1196 (D.C. Cir., Dec. 8, 2021).

[12] "Renewable Fuel Standard Program- Standards for 2019 and Biomass-Based Diesel Volume for 2020: Response to Comments." Environmental Protection Agency. November 2018. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100VU6V.pdf

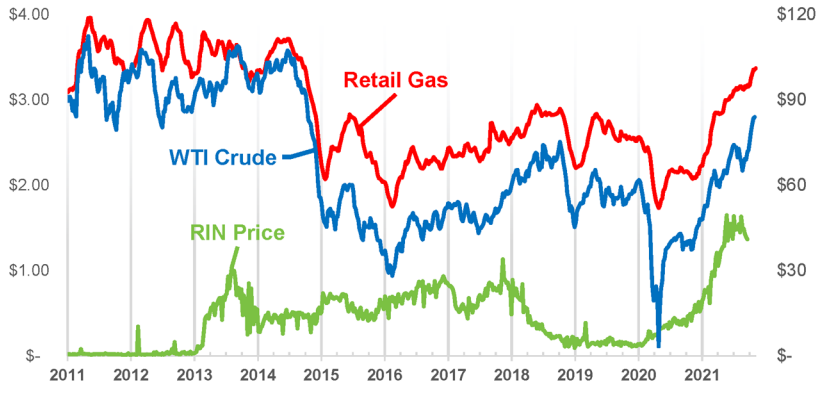
First, as EPA wrote in November 2018, refiners recoup the cost of RIN purchases when they sell petroleum products on the market. Any RIN cost is incorporated into the sell price, so refineries account for this during their transactions.

Others have also echoed the EPA analysis on RIN prices, including petroleum firms and liquid fuel economic analysts:

- "Chevron's market experience is consistent with the conclusion from several economic studies: the obligated party's RIN acquisition cost is nearly all recovered by the refiner in the gasoline and diesel fuel wholesale markets[13]."

- "RIN values represent neither windfalls for blenders nor out-of-pocket costs for refiners. Notwithstanding the fact that some companies report RIN expenses or RIN revenues as distinct line items in their financial statements, the overall impacts of RIN generation and sales (for nonintegrated blenders) and RIN acquisitions (for merchant refiners) are largely or perhaps completely offset by countervailing costs or revenues experienced by the companies in their transactions of component fuels. This conclusion has been supported by the findings of multiple academic researchers and is consistent with economic theory. Moreover, an analysis of the margins earned by merchant refiners since RIN prices began to escalate in 2013 demonstrates no adverse impact[14]."

Figure 4: Price of Retail Gas, WTI Crude, and D6 RINs



Source EIA, EPA

[13] "*Comments on Petitions for Rulemaking to Change the RFS Point of Obligation; Proposed Denials*." Chevron. Docket No.: EPA-HQ-OAR-2016-0544, Comment ID No. EPA-HQ-OAR-2016-0544-0209. February 2017. https://www.regulations.gov/document?D=EPA-HQ-OAR-2016-0544-0209.

[14] "Economic Issues Associated with a Change of the RFS Point of Obligation." Edgeworth Economics. February 2017.

Second, obligated parties have had more than 14 years to comply with the RFS, a law enacted to encourage an increasing scale of biofuel blending. Supply and demand ultimately dictate price, so blending more biofuels creates more RINs, which in turn pushes RIN prices down. The easiest way to lower RIN prices is to blend more biofuels.

As shown in Figure 4, gas prices directly correlate with the price of crude oil, not RINs. According to the EIA, crude oil is the most impactful contributor, accounting for 56% of the price of gasoline[15]. The RIN market is independent from gas prices and instead reflects the blending decisions by obligated parties.

The RFS works best when it is implemented in accordance with congressional intent. We encourage members of this committee to urge the EPA to maintain the integrity of the RFS.

Breaking Down Barriers to Biofuels: Marketplace Hurdles for Higher Blends

Currently, more than 96% of cars on the road are compatible with E15 and consumers have driven more than 28 billion miles on E15[16]. As stated earlier, a nationwide transition from E10 to E15 would lower GHGs by 17.62 million tons annually, the equivalent of removing 3.85 million vehicles from the road. Further, an ABF Economics study from June 2021[17] shows that moving to a nationwide E15 standard would offer even further economic benefits:

- Add $17.8 billion to the U.S. Gross Domestic Product;
- Create an additional 182,700 jobs;
- Generate $10.5 billion in new household income; and
- Save consumers $12.2 billion fuel costs annually, as E15 costs typically up to $0.10 less than E10.

However, the pathway to these higher-level, ethanol-blended fuels has regulatory hurdles and outdated policy assumptions. To fully realize these potential gains in economic growth and emissions reductions, we strongly recommend Congress pass legislation, the Consumer and Fuel Retailer Choice Act (S. 2339), or EPA take relevant regulatory action to restore summer sales for E15 and complete a pending rulemaking that would simplify pump labeling and broaden the use of existing fueling infrastructure for E15. In the absence of enactment of S. 2339, we would encourage the committee to support a one-year extension of the regulatory treatment of E15 that was present in the summers of 2019, 2020, and 2021, so the more than 2,500 retail stations currently selling E15 can continue to do so. Providing uninterrupted access to E15 for all Americans continues to be a top priority, and we are willing to engage with this committee and Congress to identify potential paths forward that will permanently fix this restriction in a timely manner.

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[15] "Gasoline explained – Factors affecting gasoline prices." U.S. Energy Information Administration. https://www.eia.gov/energyexplained/gasoline/factors-affecting-gasoline-prices.php

[16] "Analysis of Ethanol Compatible Fleet for Calendar Year 2021," Air Improvement Resources, Inc. November 2020. https://growthenergy.org/wp-content/uploads/2020/11/Analysis-of-Ethanol-Compatible-Fleet-for-Calendar-Year-2021-Final.pdf

[17] "Economic Impact of Nationwide E15 Use," ABF Economics. June 2021. https://growthenergy.org/wp-content/uploads/2021/06/Nationwide-E15-Use-Economic-Impact-Final.pdf

Figure 5: E15 Locations Nationwide – 2570 in 31 states



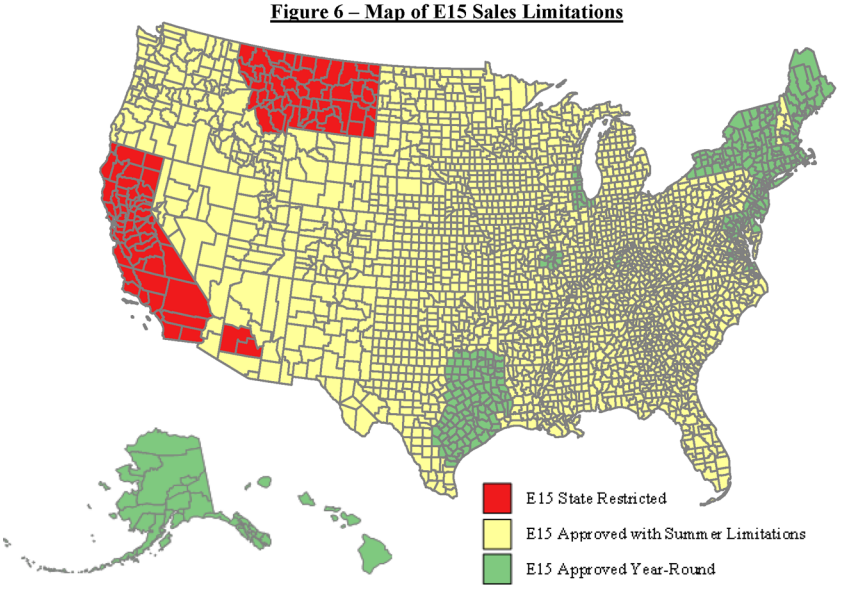
Source: Growth Energy Station Data

Summer E15 Sales Restriction

The Clean Air Act includes seasonal fuel vapor pressure provisions intended to reduce evaporative emissions in the summer months (June 1 to September 15). In the 1990 amendments to the Clean Air Act, Congress limited allowable fuel vapor pressure during the summer months to nine-pounds-per-square-inch (psi) Reid Vapor Pressure (RVP) in certain areas of the country. Congress also specified, however, that fuel blends containing 10% ethanol would receive a 1.0 psi RVP waiver from the seasonal RVP limit to encourage use of ethanol-blended fuels, which provide significant reductions in tailpipe emissions. This RVP waiver made the sale of E10 and lower ethanol blended fuels possible year-round throughout the country. However, the waiver predates the introduction of higher blends of ethanol like E15, which have a lower RVP than E10.

In May 2019, EPA clarified that E15 could be sold in the summer months, resolving ambiguity in the 1990 statute that arose because there was no 15% ethanol fuel at the time. The oil industry swiftly challenged this rulemaking in court. In a July 2021 D.C. Circuit Court of Appeals ruling, the court reversed EPA's interpretation. This ruling will have the effect of denying the majority of American drivers access to a cleaner, more affordable, biofuel blend during the summer months, starting on June 1, 2022. This move threatens the expansion of clean, homegrown, renewable energy.

Figure 6 – Map of E15 Sales Limitations



The D.C. Circuit RVP ruling affects nearly 85% of retailers currently selling E15 across 31 states and creates needless uncertainty across the marketplace. We urge the members of this committee to move swiftly to ensure uninterrupted access to lower-cost E15 for the 2022 summer and beyond, particularly as consumers seek relief from rising gasoline prices. If not addressed, the court's decision would require E15 retailers to change out fuels twice a year (on June 1 and September 15), a costly and burdensome process that increases GHG emissions, counter to congressional intent for the RFS to provide cleaner fuel choices at the pump.

This decision impacts all non-reformulated gasoline markets throughout 33 states—conventional markets outside of urban areas that are not required to participate in our nation's reformulated gasoline program. In these areas, summer sales of E15 in retail sites could fall by 85%, and the new restrictions on E15 sales would also cut overall ethanol consumption and increase greenhouse

gas emissions nationwide as more petroleum products would be used. This decision has no impact on long-standing rules that permit sales of E15 in reformulated gasoline (RFG) and other markets, which are found in 17 states. However, the largest concentration of RFG markets is in California and the Northeast, where the availability of E15 is limited.

Labeling and Equipment Compatibility



Current EPA Label



Growth Energy Proposed Label

In order to remove unnecessary barriers that prevent consumers from utilizing E15, Growth Energy supports EPA finalizing its proposed rule to address E15 fuel dispenser labeling and compatibility with underground storage tanks (UST) that would erase market hurdles for E15 adoption. We support modifying the E15 label requirement to increase clarity and ensure it clearly advises consumers of appropriate uses of the fuel, while not unnecessarily dissuading the vast majority of consumers whose vehicles can refuel with E15[18]. Either modification of EPA's E15 label or removal of the E15 label requirement entirely would expressly preempt and conflict-preempt any state or local government E15 label requirement.

In addition, Growth Energy strongly supports EPA's proposal to modify the underground storage tank compatibility requirements applicable to E15 and other fuel blends. There is ample evidence that a wide variety of fuel storage equipment, including USTs and related piping, may store E15 if it is suitable for use with E10. Removing unnecessary impediments to retailers' use of such existing equipment is imperative to providing E15 equal footing in the fuels marketplace.

Fixing these outdated and confusing barriers is critical to ensuring we can capture the emissions reduction, farm income, and lower prices that come with E15 expansion. As our nation faces the challenges of climate change, it is imperative that EPA act quickly to support greater access to cleaner renewable fuel blends for all Americans. E15 and higher ethanol-blended fuels will deliver immediate benefits for our environment and are a critical piece of our nation's efforts to reduce carbon emissions. Clearing hurdles to the sale of E15 and growing markets of biofuels would also

[18] Growth Energy Comment on EPA's NPRM "E15 Fuel Dispenser Labeling and Compatibility with Underground Storage Tanks" (Docket ID No. EPA-HQ-OAR-2020-0448). April 2021.
https://www.regulations.gov/comment/EPA-HQ-OAR-2020-0448-0051

provide an economic lifeline for rural communities as they continue to rebuild in the wake of the COVID-19 pandemic.

The Future of Biofuels: Decarbonizing Land, Air, and Sea Transportation

As carbon reduction becomes more important to the transportation sector, ethanol is poised to play a greater role in decarbonizing all forms of transportation—whether on land, in the air, or in the seas—and we are energized by the potential opportunity to expand our role in reducing our nation's carbon emissions. In addition to our current light duty vehicle market, we see promise in new and emerging low-carbon fuel markets in hard-to-electrify sectors such as aviation, marine, and heavy-duty vehicles. U.S.-based airlines used more than 18 billion gallons of jet fuel in 2019[19]. Accessing the aviation market through ethanol to sustainable aviation fuel (SAF), along with new technologies that allow ethanol to be used in marine and heavy-duty applications, provide America's ethanol industry the opportunity to be utilized in more than just light duty cars and trucks.

With the appropriate investment in critical research and development and the right policy environment, our industry can continue to decarbonize our transportation sector—from passenger vehicles to our aircraft fleet. However, in order to achieve the Biden Administration's goal of 3 billion gallons of SAF production by 2030, and 35 billion gallons by 2050 to achieve net-zero GHG emissions in aviation, we need game-changing solutions. For that, we must have a healthy and thriving corn ethanol industry and rural economy. That starts with a strong RFS, E15 as the nation's standard fuel, and accurate carbon modeling.

Legislation before Congress proposes enacting several important incentives that will help ethanol producers further reduce the CI of their fuels and explore new markets outside of light duty vehicles. We appreciate and support the inclusion of the following items:

1. **The establishment of the Clean Fuel Production Credit (CFPC, or 45CC), which provides an incentive to produce low-carbon biofuels.**
   This credit provides a producer-based tax incentive to encourage the adoption and deployment of low-carbon fuel technologies. The size of the incentive is based on the percentage of carbon reduction relative to a fixed baseline, re-orienting our biofuels tax policy toward carbon reductions instead of producing specific types of fuel.

2. **The extension and increase of the 45Q tax incentive for the capture, utilization, and storage of carbon dioxide.**
   Roughly half of our member plants either capture carbon for food and beverage use, expect to transport carbon dioxide by a carbon pipeline for permanent geologic storage, or expect to store carbon nearby for geologic storage. With 99.9% pure, clean, fermentation carbon from an ethanol plant being relatively easy to capture, our facilities provide a good opportunity to deploy carbon capture technology and appreciably lower emissions. For the average U.S. ethanol plant, carbon capture can cut the carbon intensity of their fuel in half.

[19] "Airline Fuel Cost and Consumption (U.S. Carriers - Scheduled)," Bureau of Transportation Statistics. https://www.transtats.bts.gov/fuel.asp.

3. **A credit for the blending or production of sustainable aviation fuel (SAF).**
   We support enacting a new incentive that will allow low-carbon biofuels like ethanol to help decarbonize the aviation sector. We note, however, that lifecycle carbon modeling should be comprehensive and based on the best available U.S. science. We strongly recommend that the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) Model by the Argonne National Laboratory be used for this purpose. Lastly, we recommend that incentives for SAF and carbon capture be allowed to exist side-by-side as they target different problems—reducing carbon emissions and ensuring the affordability of low-carbon SAF.

Examining a Low Carbon Fuel Standard

States like California, Oregon, and Washington are all placing an emphasis on incorporating more carbon-friendly fuel into their transportation supply through Low Carbon Fuel Standard (LCFS) and Clean Fuel Standard (CFS) programs. The LCFS and CFS place a premium on fuel sources which have lower CI scores to act as an incentive to fuel producers.

Growth Energy supports, in concept, policies like as an LCFS or CFS to incent greater use of low-carbon renewable fuel, with an express focus on getting the details of the program right, specifically how lifecycle GHG emissions are modeled and whether the program allows greater concentrations of low-carbon biofuels into the liquid fuel fix. Without an accurate accounting for lifecycle greenhouse gas emissions that reflects the latest science or an ability to grow our share of a liquid-fuel gallon with our lower-carbon product, the pathway for our industry to help meet the goals of a LCFS or CFS becomes less clear.

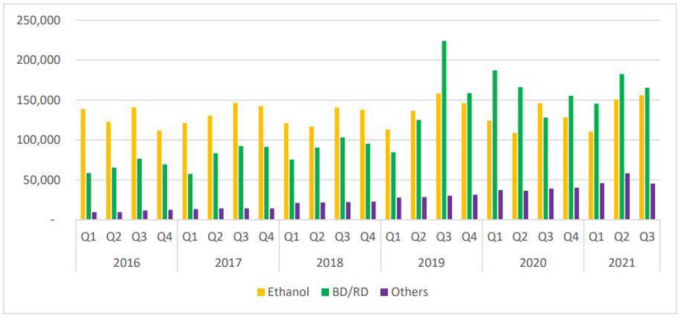
Several of the most compelling demonstrations of the essential role biofuels play in meeting climate goals are California's LCFS and Oregon's CFS. As an example, the goal of the California LCFS is to, "encourage the use of cleaner low-carbon transportation fuels in California, encourage the production of those fuels, and therefore, reduce GHG emissions and decrease petroleum dependence in the transportation sector[20]."

According to data by the California Air Resources Board (CARB), biofuels are responsible for nearly 80% of all carbon reductions credited under the LCFS, with the recorded carbon intensity (CI) of ethanol declining 33% since 2011[21].

Similarly, in Oregon, since the inception of the CFS in 2016, the carbon intensity of ethanol has decreased 20% (from 65 g/MJ to an expected to 52 g/MJ in 2022) and is expected to decrease another 3% by 2024, while the carbon intensity of gasoline blendstock remains constant until 2035 (100.14 g/MJ) and by 2024 will be more than double than that which is expected for ethanol[22].

[20] California Air Resources Board. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about
[21] "Data Dashboard: Low Carbon Fuel Standard." California Air Resources Board. May 2020. https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm.
[22] "2021 Illustrative Compliance Scenarios." ICF for the Oregon Department of Environmental Quality. July 2021. https://www.oregon.gov/deq/ghgp/Documents/cfpIlluCompScenD.pdf

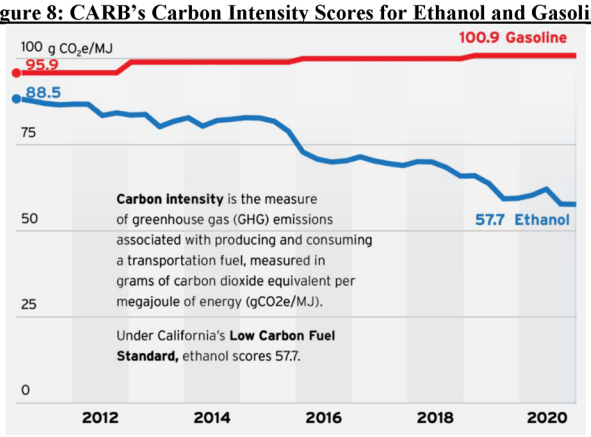
Figure 7: Oregon Department of Environmental Quality Clean Fuel Standard Credits Generated by Fuel Type (Q12016-Q32021)



Source: Oregon Department of Environmental Quality

CARB tracks the CI of a variety of fuel options and has updated the CI scores annually since the state's LCFS was adopted in January 2011. Figure 8 shows the steady decline in the CI score for ethanol and the uptick in CI score for gasoline over the same period.

Figure 8: CARB's Carbon Intensity Scores for Ethanol and Gasoline



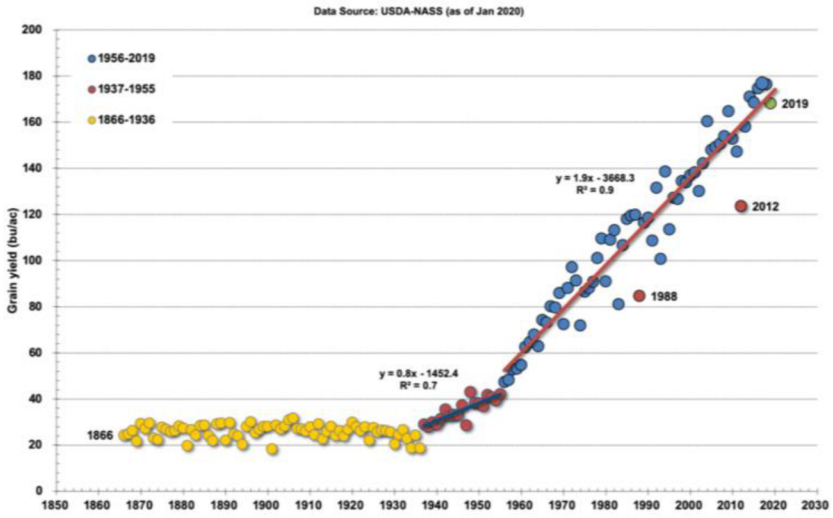
Source: California Air Resources Board

Improvements in ethanol's CI scores can be attributed to the biofuel industry's increased manufacturing efficiency through less energy-intensive energy usage, more effective biotechnology, lower water usage, and increased efficiencies in the amount of land used for biofuel feedstock production. America's corn growers are producing stronger yields with less acreage, and

biorefineries can manufacture more gallons of ethanol per bushel of corn. Total cropland acreage has fallen from 470.8 million acres in 1978 to 391.9 million acres in 2012[23].

Moreover, corn yields have increased dramatically over the last 50 years, increasing from 72.4 bushels per acre in 1970 to 172 bushels per acre in 2020. Over the last ten years, corn yield has increased by 20%[24], while land planted for corn has remained steady. Figure 9 demonstrates the improvements in corn yields over the last 150 years.

Figure 9: Corn Crop Yields 1866-2019



Source: USDA-NASS and Historical Corn Grain Yields in the U.S. (Purdue University)

America's biorefineries have deployed a number of low-carbon practices to reduce the carbon intensity of our fuel, including wind energy, solar energy, carbon capture, combined heat and power, and more. In fact, almost all capital expenditures at ethanol biorefineries today are aimed at reducing their carbon footprint to take advantage of low-carbon fuel markets like those in the western United States and abroad.

Even with significant innovation at our members' plants, farming practices still account for roughly 50-65% of the lifecycle carbon emissions of these fuels. Farmers have already responded

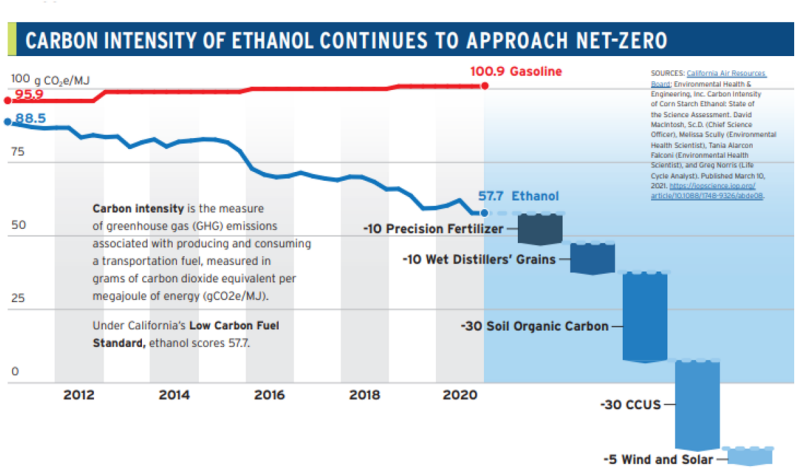
[23] "Cropland, 1945-2012, by State: The sum of cropland used for crops, cropland idled, and cropland used for pasture," U.S. Department of Agriculture's Economic Research Service. August 2017. https://www.ers.usda.gov/data-products/major-land-uses/

[24] "Crop Production Historical Track Records," National Agricultural Statistics Service. April 2021. https://www.nass.usda.gov/Publications/Todays_Reports/reports/croptr21.pdf

to the call for improved sustainability, using fewer inputs and increasing efficiencies in their farming practices. These improved practices have already helped reduce the CI of farming, and therefore the overall carbon intensity of biofuels.

Further voluntary incentives like cover crops, nutrient management, buffers, and incentives for locally led conservation efforts that will help reduce the CI of agriculture even further, helping biofuel producers provide an even lower-carbon liquid fuel at a time of rising demand for low-carbon fuels. As biofuel producers benefit from low-carbon farming practices, farmers also benefit in the form of premium prices for their commodities.

Figure 10: Achieving Net-Zero Ethanol



Source: Environmental Health & Engineering and California Air Resource Board

Biofuels continue to provide the foundation towards reaching goals set in both California's LCFS and Oregon's CFS, but the American farm economy could further benefit with improved modeling. For example, the LCFS does not currently account for low-carbon farming practices when rating the CI for various biofuels. Using less fertilizer through precision agriculture technologies lowers nitrogen use and would improve ethanol's CI score. Further improvements also include adopting farming techniques like no-till and planting cover crops that keep nutrients in soil. The CI score can also be lowered significantly through the use of updated modeling that accurately reflects the carbon sequestered with the planting of corn, a natural carbon sink. Accounting for the CI benefits brought by these techniques and more would provide a greater premium for ethanol producers and the farmers they support.

Biorefineries are researching and implementing technological improvements to further reduce the carbon intensity of ethanol. As demonstrated in Figure 10, biorefineries have the potential to reach

net-zero ethanol and even achieve negative carbon emissions using today's technology. Some examples include installing more renewable sources of energy including wind and solar and installing carbon capture and sequestration equipment.

Sustainable farming practices can also have an impact on reducing a biorefinery's carbon intensity score. Precision fertilizer and accurately accounting for the carbon sequestered with the planting of corn are other examples of methods to further reduce carbon intensity.

Higher Octane Fuels Help to Drive Lower Vehicle Greenhouse Gas Standards and Better Fuel Economy

It is imperative to consider the benefits of using high-octane, low-carbon fuels to make engines more efficient. Beyond E15, Growth Energy has been a leader on highlighting the need for higher-octane, mid-level ethanol blends, first submitting a proposal for a 100 research octane number (RON), E30 fuel nearly a decade ago. By moving towards higher-octane, lower-carbon mid-level blends, automakers can optimize engines to further improve efficiency and further reduce both greenhouse gas and tailpipe emissions.

The science supporting the benefits of a high-octane, low-carbon midlevel blend in conjunction with a high compression ratio engine is not new, and has been well-explored by the national labs, automobile manufacturers, and other scientific institutions[25]. Ethanol has a very high-octane number, a lower-carbon content than the gasoline components it replaces, and myriad of other benefits that assist in combustion to increase engine efficiency and reduce both greenhouse gas and tailpipe criteria pollutant emissions.

We urge the committee to work with USDA, EPA, and the Department of Transportation to move quickly to require a minimum octane standard, as well as to approve a high-octane, mid-level, ethanol blend such as that first proposed by Growth Energy for vehicle certification as well as for consumer use. Additionally, we strongly support the Next Generation Fuels Act (H.R. 5089) introduced by Congresswoman Bustos. This important legislation would increase the use of high-octane, low-carbon biofuels while limiting the use of harmful petroleum additives. We urge Congress to consider and enact this key legislation.

America's Ethanol Industry is an Important Economic Driver

America's ethanol industry is also the second-largest customer to 300,000 U.S. corn growers, with roughly one-third of the field corn crop used to produce fuel ethanol each year[26]. In a particularly unusual year of depressed demand in 2020, the ethanol industry purchased 4.78 billion bushels of corn to produce nearly 14 billion gallons of biofuels and more than 36.4 million tons of dried

[25] "Summary of High-Octane, Mid-Level Ethanol Blends Study." Oak Ridge National Laboratory. July 2016. https://info.ornl.gov/sites/publications/Files/Pub61169.pdf.
[26] National Corn Growers Association. https://www.ncga.com/key-issues/current-priorities/ethanol

distillers' grains[27]. Also in 2020, 26.6% of field corn went into fuel ethanol[28]. In 2021, our industry purchased nearly 30 billion dollars of corn to produce ethanol and co-products such as high-protein animal feed and corn oil.

Rural communities are eager to lead this charge, and the benefits to our economy are significant, especially as the cost of oil surges. With this homegrown energy comes homegrown jobs, from farmers to union professionals. As Daniel Duncan, Executive Secretary-Treasurer of the Maritime Trades Department, AFL-CIO, stated, "[u]nion members are not just on the production side of the American biofuel industry, but also build, operate, and maintain the infrastructure that keeps homegrown fuels like ethanol and biodiesel flowing. This sector is an important source of strength for union jobs, especially when it comes to growth in agricultural regions of the nation[29]."

Figure 11: Contribution of Ethanol Production to Individual State Economies, 2019

	Production (Mil Gal)	Production Share	GDP ((Mil $)	Employment Jobs	Income (Mil $)
IA	4,126	26.0%	$9,096	82,294	$4,910
NE	2,176	13.7%	$4,797	43,401	$2,589
IL	1,833	11.5%	$4,041	36,560	$2,181
MN	1,315	8.3%	$2,900	26,232	$1,565
IN	1,083	6.8%	$2,388	21,601	$1,289
SD	1,002	6.3%	$2,209	19,985	$1,192
WI	648	4.1%	$1,429	12,924	$771
ND	487	3.1%	$1,074	9,713	$579
KS	518	3.3%	$1,142	10,332	$616
OH	408	2.6%	$900	8,138	$485
TX	335	2.1%	$739	6,682	$399
MI	283	1.8%	$624	5,644	$337
TN	230	1.4%	$507	4,587	$274
MO	165	1.0%	$364	3,291	$196
NY	165	1.0%	$364	3,291	$196
CA	158	1.0%	$348	3,151	$188
CO	125	0.8%	$276	2,493	$149
GA	120	0.8%	$265	2,393	$143
PA	110	0.7%	$243	2,194	$131

*Excludes construction, exports and R&D

Source: ABF Economics

In a February 2020 study, ABF Economics broke down the economic impact ethanol production brought to each state in 2019 which is shown in Figure 11[30].

[27] "Grain Crushings and Co-Products Production- 2020 Summary." U.S. Department of Agriculture. March 2021. https://downloads.usda.library.cornell.edu/usda-esmis/files/v979v304g/jh344m06h/1j92h279h/cagcan21.pdf
[28] "Corn Usage by Segment 2020." National Corn Growers Association. April 2021. https://www.worldofcorn.com/#corn-usage-by-segment
[29] "Biofuel Industry Boosts Union Jobs." Seafarers International Union. November 2021. https://www.seafarers.org/biofuel-industry-boosts-union-jobs/
[30] "Contribution of the Ethanol Industry to the Economy of the United States in 2019." Urbanchuk, John M., Managing Partner. February 2020. https://files.constantcontact.com/a8800d13601/9e769376-3aef-4699-b31f-3c6415b8fa63.pdf

Conclusion

The biofuel industry stands ready to work with this committee, Congress, and the Biden Administration to meet our national commitments to attaining aggressive climate goals by mid-century while supporting economic development, working families, and renewable energy. With forward-leaning policies that support innovation and access to markets, our industry will continue to reduce our carbon footprint, create more clean energy jobs, spur economic activity in rural communities, and provide drivers across the country with affordable, clean fuel choices today.

Congress can help accelerate our transition to a clean energy future with a strong RFS, consumer access to high-concentration ethanol blends, and incentives to allow biofuels to reduce the carbon footprint of transportation, especially hard-to-decarbonize sectors like aviation, marine, and heavy-duty shipping. Ensuring the RFS is administered as intended by Congress will guarantee that we blend more low-carbon renewable fuel in our transportation sector each year.

In short, we have ample opportunity to achieve our renewable energy goals while supporting an industry that has supported rural America and clean energy for decades. I appreciate the opportunity to participate in this important hearing on how the RFS improves the American economy and helps our country reach its climate goals.

Thank you and I look forward to answering your questions.

Senate Committee on Environment and Public Works
Hearing Entitled, "*The Environmental Protection Agency's Renewable Fuel Standard: Challenges and Opportunities*"
February 16, 2022
Questions for the Record for Emily Skor

Chairman Carper:

1. Despite decades of oil and gasoline price spikes in the United States, the American people still have very little choice at the pump when it comes to the type of fuel they can use to fuel their vehicle. Our economy continues to be tied to the price of oil, which as we see too well today, is impacted by foreign events and the world economy. One of the goals of the Renewable Fuel Standard (RFS) is to help transition the United States away from oil and toward a cleaner, domestic supply of fuel for our transportation sector.

    a. In your opinion, does the federal Renewable Fuel Standard program and state low carbon fuel standard programs, such as the Oregon's Clean Fuel Program, help reduce our nation's dependence on foreign oil? If yes, please discuss further.

    Yes, programs like the Renewable Fuel Standard (RFS) and state low carbon fuel programs incentivize additional use of renewable biofuel to reduce the use of petroleum products. Each gallon of domestically-produced biofuel offsets a gallon of petroleum-based fuel, primarily those imported from troubled regions around the globe. In fact, at today's blending levels, ethanol already displaces the gasoline produced from 700 million barrels of oil every year, and the RFS is one of the most successful carbon reduction policies on the books today, offsetting over 1 billion tons of carbon since 2008.

    b. Please discuss further how higher blends of ethanol and renewable fuels, as a result of the Renewable Fuel Standard, lower consumer prices of gasoline and diesel, rather than raise costs.

    Ethanol trades at a lower price than wholesale gasoline such as Reformulated Blendstock for Oxygenate Blending (RBOB), a component used to create reformulated gasoline. For example, on March 14th Chicago Ethanol Platts Futures traded at $2.515 while RBOB traded at $3.8221. This is a significant price advantage for biofuels, and due to several reasons. First, our biofuel producers are improving their production process and are able to produce more ethanol gallons per bushel of corn than ever before on less land. Second, ethanol feedstocks tend to be sourced locally, cutting down on the transportation costs of our inputs. Lastly, petroleum product pricing is set at the mercy of global markets and major oil-producing countries that control much of the world's supply.

Furthermore, higher blends of ethanol (E15, E30, E85) are even more affordable than the standard blend of gasoline, which typically contains 10 percent ethanol. E15, a blend that contains 15 percent ethanol, sells on average for up to 10 cents per gallon less than E10, however on March 10th, we saw E15 priced at 57 cents less than E10 in southern Minneapolis, Minn. That same week, we saw E85 in California sold for three dollars less a gallon than traditional fuel – a true example of consumer savings.

We need to increase consumer access to more affordable, higher biofuel blend choices at the pump, but consumer access is in jeopardy – and unless action is taken, consumers in most fuel markets will lose the E15 option this summer – when Americans drive the most. This is because the D.C. Circuit Court of Appeals reversed the Environmental Protection Agency's (EPA) removal of outdated restrictions on the summertime sale of E15, threatening the expansion of clean, homegrown renewable energy and increasing greenhouse gas emissions. This ruling affects nearly 85% of retailers currently selling E15 across 31 states, and would create needless uncertainty across the marketplace. Policymakers must move swiftly to ensure uninterrupted access to lower-cost E15 this summer and beyond, particularly as consumers seek relief from rising gasoline prices. We would recommend passing S. 3787, the Home Front Energy Independence Act, or S. 2339, the Consumer and Fuel Retailer Choice Act, to ensure that E15 access continues uninterrupted.

c. In your opinion, would a more flexible low carbon fuel program at the federal level that expands the opportunities for advanced biofuels and other clean fuels, similar to Oregon's Clean Fuel Program, help reduce our nation's dependence on foreign oil and as a result help mitigate consumer cost spikes when global oil prices spike? If yes, please discuss.

Yes. Any properly crafted program which encourages low-carbon, low-cost homegrown biofuels will give American consumers greater access to fuels with less petroleum and can build upon the success of the RFS already in place. Furthermore, the U.S. ethanol industry has the capacity to produce 17 billion gallons of biofuel annually, further reducing our dependence on foreign markets to dictate the prices for these fuels. Especially today when the retail price of gas is over four dollars a gallon nationwide, American consumers need affordable fuel choices that also reduce our dependence on oil.

2. During the hearing, these was a lot of discussion about whether the Renewable Fuel Standard raises consumer prices or not. At the same time, witnesses agreed that the

largest driver of costs for consumers in terms of gasoline and diesel prices at the pump, comes from the price of oil, not from environmental programs such as the Renewable Fuel Standard. For the record, please discuss further how higher blends of ethanol and renewable fuels blended into our transportation fuel as a result of the Renewable Fuel Standard, have lowered consumer prices of gasoline and diesel, rather than raised costs. In your answer, can you please provide economic studies that help support your answer?

Non-ethanol gasoline – sold at retail as E0 – costs 50-80 cents more per gallon on average than gasoline with 10 percent ethanol. Higher blends of ethanol (E15, E30, E85) are even more affordable than the standard blend of gasoline, which typically contains 10 percent ethanol. E15, a blend that contains 15 percent ethanol, sells on average for up to 10 cents per gallon less than E10 however on March 10th, we saw E15 priced at 57 cents less than E10 in southern Minneapolis, Minn. That same week, we saw E85 in California sold for three dollars less a gallon than traditional fuel – a true example of consumer savings. The RFS is the policy mechanism that helps drive these savings.

Further, an ABF Economics study[1] from June 2021 shows that moving to a nationwide E15 standard would offer even further economic benefits:

- **Add $17.8 billion to the U.S. Gross Domestic Product;**
- **Create an additional 182,700 jobs;**
- **Generate $10.5 billion in new household income; and**
- **Save consumers $12.2 billion fuel costs annually, as E15 costs typically up to $0.10 less than E10.**

3. During the hearing, the Committee received testimony from Ms. Cory-Ann Wind, Oregon's Clean Fuels Program Manager, about Oregon's state-level low carbon fuel standard program. Oregon's Clean Fuels Program sets a declining target for the average life cycle carbon intensity of transportation fuels used in the state. As we heard during the hearing, Oregon's program allows flexibility to meet the statewide target and provides greater certainty than the federal Renewable Fuel Standard program by setting volume requirements years into the future.

    a. How would the biofuels industry benefit from having volume obligations set years into the future, instead of on an annual basis?

    EPA has missed its annual November 30th Renewable Volume Obligation (RVO) deadline several times, and is currently late in setting the 2021 and 2022 RVOs as well as the RFS "Set" as of today. Setting RVOs several years into the future

[1] "Economic Impact of Nationwide E15 Use," ABF Economics. June 2021. https://growthenergy.org/wp content/uploads/2021/06/Nationwide-E15-Use-Economic-Impact-Final.pdf

could vastly improve market uncertainty that has come from a year-by-year RVO requirement. Greater certainty allows for planning and investment by the industry in new markets and sectors of decarbonization, such as Sustainable Aviation Fuels (SAF), maritime, and heavy-duty trucking. The downside of setting multiple year RVOs is that EPA may be too cautious in setting bold, forward-looking, low-carbon volumes because they are trying to meet an artificial multi-year time frame that is difficult to project. EPA would need to balance these competing forces between certainty and boldness in order to make a multi-year proposal work.

b. What other elements of existing low carbon fuel standard policies, including elements of Oregon's Clean Fuels Program, could help encourage further investment in biofuels, including advanced biofuel technologies?

Growth Energy supports the concept of a low carbon fuel standard (LCFS) in conjunction with the RFS, and we believe the details of a program are incredibly important. First and foremost, the modeling used to determine the carbon intensity of any qualifying fuel must be comprehensive, objective, and not unfairly advantage a particular fuel or practice. Second, the program must be technology neutral in its construction. Lastly, from the vantage point of America's ethanol industry, it needs to allow higher concentrations of biofuels in the fuel mix, such as E15.

4. Existing low carbon fuel standard programs base incentives on lifecycle analysis of fuel pathways. Different state-level programs utilize different modeling to determine the carbon intensity of eligible fuels.

a. What benefits are there associated with existing models that are used in state-level low carbon fuel standard programs?

Most of the different models utilize the Department of Energy's (DOE) Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) Model in whole or in part. GREET is updated annually using the best available and most current science – with the largest data set – when evaluating the carbon intensity score of various fuels, and we strongly urge the use of GREET when evaluating the lifecycle carbon emissions of ethanol.

b. What challenges exist with existing models that are used in state-level low carbon fuel standard programs?

The same gallon of ethanol produced at any of our country's more than 200 biorefineries will have a different carbon intensity score under GREET, EPA's outdated RFS predictive model, Oregon's Clean Fuels Program,

California's Low Carbon Fuel Standard, or multiple other models used in foreign nations. With inconsistent scores, that same gallon of ethanol has different low carbon incentive values in multiple locations. In order to encourage uniformity and eliminate non-conforming results across multiple low carbon platforms, we urge the use of the GREET model when evaluating the lifecycle carbon emissions of ethanol.

5. What other policies that were not discussed at the hearing should we consider to increase the flexibility and certainty for stakeholders and encourage greater deployment of more sustainable fuels?

SAF has been discussed at great length over the past year as President Biden set an aggressive 3-billion-gallon SAF production target by 2030 and a 35-billion-gallon SAF production target by 2050. Biofuel producers are eager to meet this challenge and are actively exploring methods to produce SAF. In order to meet this challenge, we need to have a strong and vibrant ethanol industry today, and we must ensure that the life cycle assessment model used reflects the most accurate and up-to-date science available.

To address climate change, Congress is currently reviewing methods to encourage fuel producers to make SAF, including tax incentives. To qualify, fuel producers must offer a renewable fuel that significantly reduces carbon emissions compared to petroleum-based jet fuel.

However, Congress is considering using a model from the International Civil Aviation Organization (ICAO), a United Nations agency, when modeling the carbon intensity of various fuels. The science within this model is severely outdated and 10-15 years old. In fact, ICAO actually rates petroleum-based jet fuel better than U.S. corn-grain ethanol, which is blatantly inaccurate.

The U.S. Department of Energy's GREET Model is already in use and incorporates up-to-date science which more accurately scores carbon intensity for ethanol and other renewable fuels.

Congress should be using a U.S.-based lifecycle emissions model when determining U.S.-based tax incentives. Without a change in modeling to GREET, U.S biofuel producers will not be able to participate in the SAF market, and rural communities will be locked out from contributing to a cleaner climate, and our ability to decarbonize the airline fleet will suffer.

Additionally, we are supportive of the Clean Fuels Production Credit, which provides an incentive for fuels that are a certain percentage below a baseline standard based on carbon reduction under the GREET model (for non-aviation fuels). This flexible incentive encourages and incents renewable fuel producers to implement carbon reducing technology at our plants and on the farm, with incentives based solely on how much carbon can be reduced.

We also supportive the 45Q tax incentive for the capture, utilization, and sequestration of carbon. The biogenic process of fermentation at ethanol facilities emits 99.9 percent pure carbon that can be captured and utilized for food and beverage applications as well as for permanent geologic storage.

6. People living in areas with heavy vehicle traffic are more likely to be minority and low-income populations and are disproportionately impacted by toxics and particulate matter emitted from internal combustion engines. How does the use of biofuels, including ethanol, help address the environmental justice impacts of air pollution from vehicle emissions?

We agree that minority and low-income populations are disproportionately impacted by toxics and particulate matter emitted through the use of petroleum products used in transportation. Clean, renewable ethanol is the most affordable and abundant alterative to toxic fuel additives, including benzene, toluene, ethylbenzene, and xylene (BTEX). BTEX play a dominant role in the formation of toxic emissions linked to cancer, neurological, cardiovascular, and reproductive damage and drive significant increases in particulate emissions, which cause asthma and contribute to heart and lung disease.

Greater use of biofuels provides tangible advantages with respect to human health, particularly in overburdened communities. A University of California- Riverside study found ethanol blends reduce toxic emissions by up to 50%, including smog and ultra-fine particulates[2]. A University of Illinois at Chicago study found replacing traditional gasoline with E10 reduces toxic emissions by 15%, while E20 could reduce toxins by 31.7%[3].

Lastly, a move to E15 would reduce CO2 emissions by more than 17.62 million tons, the equivalent of taking 3.85 million cars off the road each year. In short, biofuels will significantly reduce the amount of toxics emitted by petroleum products, and the advantages increase with higher blends of ethanol.

7. As I mentioned in the hearing, EPA tracks compliance with the Renewable Fuel Standard by using tradable credits, referred to as renewable identification numbers or RINs. Refiners and importers can generate RINs either by blending biofuels into fuel or by purchasing RINs from another party through what is known as the RIN market. Would

[2] "Investigating the Effect of Varying Ethanol and Aromatic Fuel Blends on Secondary Organic Aerosol Forming Potential for a FFV-GDI Vehicle. University of California—Riverside Chemical and Environmental Engineering. Patrick Roth, Jiacheng Yang, Ayla Moretti, Tom Durbin, David Cocker, Georgios Karavalakis, Akua Asa-Awuku. https://fixourfuel.com/wp-content/uploads/2018/04/UC-Riverside-Study.pdf.

[3] "The Impact of Higher Ethanol Blend Levels on Vehicle Emissions in Five Global Cities." U.S. Grains Council. Dr. Steffen Mueller at University of Illinois at Chicago. Grains.org/wp-content/uploads/2018/11/Complete-StudySummary.pdf.

you discuss how RIN prices help drive the additional blending of renewable fuels and how RIN costs do not directly impact consumer costs?

Renewable Identification Numbers (RINs) were included in the RFS to add flexibility to the compliance mechanism of the RFS at the specific request of the petroleum industry. Obligated parties have the option to either blend biofuels and generate RINs or purchase RINs to meet their obligations under the RFS. To be clear, there is no relationship between RIN prices and refinery profits, as EPA has repeatedly stated:

> **"We do not believe that the price paid for RINs is a valid indicator of the economic impact of the RFS program on these entities [refiners], since a narrow focus on RIN price ignores the ability for these parties to recover the cost of RINs from the sale of their petroleum products[4]."**

First, as EPA wrote in November 2018, refiners recoup the cost of RIN purchases when they sell petroleum products on the market. Any RIN cost is incorporated into the sell price, so refineries account for this during their transactions. Others have also echoed the EPA analysis on RIN prices, including petroleum firms and liquid fuel economic analysts:

- **"Chevron's market experience is consistent with the conclusion from several economic studies: the obligated party's RIN acquisition cost is nearly all recovered by the refiner in the gasoline and diesel fuel wholesale markets[5]."**
- **"RIN values represent neither windfalls for blenders nor out-of-pocket costs for refiners. Notwithstanding the fact that some companies report RIN expenses or RIN revenues as distinct line items in their financial statements, the overall impacts of RIN generation and sales (for nonintegrated blenders) and RIN acquisitions (for merchant refiners) are largely or perhaps completely offset by countervailing costs or revenues experienced by the companies in their transactions of component fuels. This conclusion has been supported by the findings of multiple academic researchers and is consistent with economic theory. Moreover, an analysis of the margins earned by merchant refiners since RIN prices began to escalate in 2013 demonstrates no adverse impact[6]."**

Second, obligated parties have had more than 14 years to comply with the RFS, a law enacted to encourage an increasing scale of biofuel blending. Supply and

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[4] "Renewable Fuel Standard Program- Standards for 2019 and Biomass-Based Diesel Volume for 2020: Response to Comments." Environmental Protection Agency. November 2018. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100VU6V.pdf

[5] Comments on Petitions for Rulemaking to Change the RFS Point of Obligation; Proposed Denials." Chevron. Docket No.: EPA-HQ-OAR-2016-0544, Comment ID No. EPA-HQ-OAR-2016-0544-0209. February 2017. https://www.regulations.gov/document?D=EPA-HQ-OAR-2016-0544-0209.

[6] Economic Issues Associated with a Change of the RFS Point of Obligation." Edgeworth Economics. February 2017.

demand ultimately dictate price, so blending more biofuels creates more RINs, which in turn pushes RIN prices down. The easiest way to lower RIN prices is to blend more biofuels. As was shown in my written testimony, gas prices directly correlate with the price of crude oil, not RINs. According to the EIA, crude oil is the most impactful contributor, accounting for 56% of the price of gasoline. The RIN market is independent from gas prices and instead reflects the blending decisions by obligated parties.

Ranking Member Capito:

1. How important are liquid fuels?
   a. Do you think liquid fuels are going away anytime soon?

      No, the EIA projects that in 2050, 79% of new car sales, including flex-fuel vehicles, will have internal-combustion engines[7]. Today, there are nearly 260 million light-duty vehicles on the road today and less than 2 percent of sales over the last decade have been for electric vehicles.[8]

   b. If regulations pushed liquid fuels out of the marketplace in favor of alternatives like electric charging, what would it mean for members of your association?

      We believe the best way for liquid fuels to meet the challenge of a low-carbon economy is to reduce their carbon intensity, which for the light duty vehicle fleet is to use more ethanol. Moreover, our members are examining other uses for our low-carbon fuel in hard-to-electrify spaces like heavy-duty shipping, marine, and aviation.

2. In response to a question during the hearing, you stated "… the price of the RIN has no bearing on the price of fuel at the pump." However, it was also posited to you at the hearing that EPA and the American Petroleum Institute have said that oil refineries recover RIN costs; an assertion you did not disagree with. How can RIN prices have no bearing on the price of gasoline if oil refineries recover RIN costs downstream, ultimately to be paid for by consumers?

   The primary driver of gasoline costs is the price of oil. According to the EIA, crude oil is the most impactful contributor to gasoline prices, accounting for 56% of the price of gasoline[9].

   The easiest way for an obligated party to alleviate any RIN cost is to blend more biofuels, as each gallon of ethanol blended contains a RIN for free. Obligated parties have had more than 14 years to adjust to the RFS, and many refiners have added

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[7] Annual Energy Outlook 2022, U.S. Energy Information Administration. https://www.eia.gov/outlooks/aeo/pdf/AEO2022_Narrative.pdf (Page 7).
[8] Alliance for Automotive Innovation Electric Vehicle Sales Dashboard: electric-vehicle-sales-dashboard (autosinnovate.org)
[9] "Gasoline explained – Factors affecting gasoline prices." U.S. Energy Information Administration. https://www.eia.gov/energyexplained/gasoline/factors-affecting-gasoline-prices.php

blending capacity which actually has allowed them to realize additional revenue from blending biofuels. To the extent there are any costs for a refiner, these are equally offset as revenues by others in the gasoline supply chain, resulting in a net-zero cost to those in the fuel supply chain.

3. Would you agree that the price of gasoline inputs, such as crude oil, impact the price of gasoline?

Yes. The EIA estimates that crude oil accounts for 56% of this cost.

   a. Do ethanol blending costs and compliance costs associated with blending requirements not also contribute to gasoline input costs?

No. RINs were included in the RFS to add flexibility to the compliance mechanism of the RFS. Obligated parties have the option to either blend biofuels and generate RINs or purchase RINs to meet their obligations under the RFS. The RFS was designed to allow for a RIN market for refiners who choose to blend biofuels. Those refineries which choose to purchase RINs have any cost offset by the revenues others realize from additional biofuels blending in other parts of the gasoline supply chain, resulting in a net-zero cost for those in the fuel supply chain.

   b. If not, why would other gasoline blendstocks contribute to the price of gasoline, but not ethanol?

Ethanol does contribute to the cost of finished fuel, but only for the actual cost of the physical ethanol, which in recent days has traded $1.20 less than wholesale gasoline. Additionally, as ethanol is a less expensive octane enhancer, non-ethanol gasoline – sold at retail as E0 – costs 50-80 cents more per gallon on average than gasoline with 10 percent ethanol. That cost advantage only grows as ethanol concentrations increase.

4. The US Energy Information Administration (EIA) said that refining costs and profits in 2020 were responsible for 25 percent of the retail price of a gallon of gasoline. Additionally, the EIA stated, "The characteristics of the gasoline produced depend on the type of crude oil that is used and the type of processing technology available at the refinery where it is produced. Gasoline prices are also affected by the cost of other ingredients that may be blended into the gasoline, *including fuel ethanol*." Is the EIA wrong in saying that the cost of blending fuel ethanol into gasoline affects gasoline prices?

Like any other commodity, ethanol is not free and does have a cost when purchasing it. The reference here from the EIA refers specifically to the price of ethanol as a commodity, not any perceived costs associated with RFS compliance. Over time, ethanol has consistently traded lower than gasoline, and any examination of ethanol-free gasoline and ethanol-blended gasoline shows that fuel with ethanol has significant cost savings. A recent analysis shows that ethanol trades at a lower price

than Reformulated Blendstock for Oxygenate Blending (RBOB), a component used to create reformulated gasoline. For example, on March 14th Chicago Ethanol Platts Futures traded at $2.515 while RBOB was at $3.8221.

5. The 117th Congress is considering several energy tax provisions. Among these are enhanced tax credits for various kinds of alternative fuels and advanced biofuels, including for sustainable aviation fuel. Do you have any concerns that more favorable tax treatment for subcategories like sustainable aviation fuel may have unintended consequences for other types of transportation fuels, such as biodiesel and renewable diesel, that compete for the same input feedstocks?

As our country continues to decarbonize the transportation sector, the biofuels industry is looking to make investments and meet the demands that a potential SAF market will provide. As noted in your question, Congress is currently reviewing methods to encourage fuel producers to make SAF, including tax incentives. To qualify, fuel producers must offer a renewable fuel that significantly reduces carbon emissions compared to petroleum-based jet fuel.

However, some want Congress to mandate using the ICAO, a United Nations agency, model to evaluate the carbon intensity of various aviation fuels. The science within this model is severely outdated at 10-15 years old. In fact, ICAO actually rates petroleum-based jet fuel better than U.S. ethanol, which is not supported by U.S. research or U.S.-based carbon models.

The DOE's GREET Model is already in use and incorporates up-to-date science which more accurately scores carbon intensity for ethanol and other renewable fuels.

Congress should be using a U.S.-based lifecycle emissions model when determining U.S.-based tax incentives. Without a change in modeling to GREET, U.S. biofuel producers will not be able to participate in the SAF market, and rural communities will be locked out from contributing to a cleaner climate, and our ability to decarbonize the airline fleet will suffer.

   a. What potential implications do these sorts of preferential policies have for supply and demand of other biofuels, prices for consumers buying these fuels, as well as the broader transportation fuel sector's ability to meet requirements under the RFS?

SAF will provide America's ethanol producers with a potential new market for their product, allowing our industry to differentiate beyond the light-duty vehicle market.

Over time and with the appropriate investment in critical research and development and the right policy environment, we know our industry can continue to help decarbonize our transportation sector—from passenger vehicles to our aircraft fleet.

For the U.S. to meet its climate goal of net-zero emissions by 2050, we have to quickly expand the volume of low-carbon biofuels across the entire transportation sector.

Senator Ernst:

1. Ms. Skor, given the recent turmoil in Ukraine and the impact that is having on energy prices, what are some of the things Congress can do to empower biofuels to increase our energy security and lower the price at the pump?

Now more than ever, consumers need additional, lower-cost, low-carbon options at the fuel pump by allowing E15 to be sold year-round. In May 2019, EPA clarified that E15 could be sold in the summer months by extending the RVP waiver to E15. The oil industry swiftly challenged this rulemaking in court. In a July 2021 D.C. Circuit Court of Appeals ruling, the court reversed EPA's interpretation. This ruling will have the effect of denying the majority of American drivers access to a cleaner, more affordable biofuel blend during the summer months, starting on June 1, 2022. This move also threatens the expansion of clean, homegrown, renewable energy.

This is why we strongly support congressional and administrative efforts to extend the RVP waiver to E15, a fuel option which is on average 10 cents less expensive than conventional gasoline with 10 percent ethanol. Gas prices are shattering record-level highs with the ongoing Russia-Ukraine conflict and we need to increase our use of higher biofuel blends to shield American drivers from volatile oil markets. Even so, on March 10th, E15 was 57 cents a gallon lower than E10 at a retail location in southern Minneapolis, Minn. We urge Congress to support E15 so consumers continue to have this lower-cost option can continue to reach consumers through the 2022 summer driving season. We would recommend passing your bill, S. 3787, the Home Front Energy Independence Act, or S. 2339, the Consumer and Fuel Retailer Choice Act, to ensure that E15 access continues uninterrupted.

Senator CARPER. Thanks very much for joining us, and for your testimony.

Mr. Pugliaresi, you are recognized. Please proceed.

STATEMENT OF LUCIAN PUGLIARESI,
PRESIDENT, ENERGY POLICY RESEARCH FOUNDATION, INC.

Mr. PUGLIARESI. Thank you, Senator.

Could we queue up the charts, please?

Chairman Carper, Ranking Member Capito, members of the Committee, thank you for this opportunity to make some comments on the EPA's Renewable Fuel Standard and our management of the program.

I am President of the Energy Policy Research Foundation. We have been around since 1944. I also want to thank EPRINC's Senior Director, Max Pyziur, for helping me with the testimony and the preparation of the charts.

The first thing I would like to say is that in all our work over the years, and we testified here, actually, in 2016, we have always said that biofuels, and particularly ethanol, represent a very important component of the fuel supply for the U.S. It is a very cost effective way to get octane and extend the supply.

A basic criticism of the program is not in with biofuel; it is with the mandate. Let's go to the first chart. As you can see in the first chart, and Chairman Carper talked about this already, we are not hitting the original targets of the Energy Security Act. In fact, there are a lot of reasons for that. You can see now we are about 20 billion against the initial proposed target of 36.

The basic reason we are not hitting the target is because our expectations were wrong. There is a lot of uncertainty in the future of oil and gas prices and supply and demand, and in 2007, expectations were that gasoline demand was going to grow dramatically by about 30 percent over the next 20, 30 years. In fact, it declined dramatically.

And this made it more difficult to incorporate biofuels because when biofuels become a large percentage of the gasoline pool, the costs rise. There are actually quite low cost and actually save money up to around the 10 percent, above 10 percent, compliance costs rise. You can see this here.

This is actually very interesting to us, because when we testified in 2016, we informed the Committee that there was a certain price risk to the program, that if you try to drive these biofuels by mandates above 10 percent of the gasoline pool, the compliance costs escalate.

As Chairman Carper pointed out, the RIN credits are one way to understand what the program costs. We estimated that, using the CBO scenarios alone, that the increase in the cost of the program per gallon to consumers could be anywhere from 30 to 50 cents. Well, today, RIN prices are driving up the cost of gasoline about 28 and a half to 30 cents.

You can see this is something called the crack spread. I am not going to bore you with this, but in a way, the crack spread is what it costs to take crude oil and turn it into gasoline, diesel fuel, and other petroleum products.

You can see here that when we had a period, and LeAnn is going to talk a lot about this, but before EPA changed the rule on how to treat the credits under the exemption, the small refiner exemptions were driving down RIN prices, because it essentially increased the volume, but that program has ended. Combined with the acceleration in prices as we come out of the COVID, we now have very high RIN prices in the U.S., and these are reflected in this chart.

The other issue I would like to point out is that we are now entering a period of very high oil prices. And in this period, preceding this, prices were low, and a lot of the costs of the program were masked, because as Ms. Skor pointed out, a big percentage of the cost of gasoline and products is crude oil.

I would like to show you here, from California, the problem is yes, crude oil might be contributing about $2, but an array of programs, low carbon fuel standard, RFS, Federal taxes, all of these are contributing to the cost. So, we just have to keep this in mind, that one of the components of high gasoline prices are these programs.

I think I will just flip to the end of my comments here. As we go forward, our future is very uncertain. I really encourage Congress to give some guidance to EPA, because unless we have a set of programs which are robust against uncertainty, we are likely to have a lot of dislocations. This is the fundamental problem with the program, which is the mandate.

Thank you so much.

[The prepared statement of Mr. Pugliaresi follows:]

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Testimony

before

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"The Environmental Protection Agency's Renewal Fuel Standard program"

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Dirksen Senate Office Building (Room 406)

Submitted by:

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Washington, D.C.
www.eprinc.org

Chairman Carper, Ranking Member Capito and members of the Senate Committee on Environment and Public Works, I want to thank you for the opportunity to testify on the U.S. Environmental Protection Agency's Renewable Fuel Standard (RFS) and the U.S. Environmental Protection Agency's (EPA) management of this program. I am President of the Energy Policy Research Foundation, Inc. (EPRINC), a non-profit public policy research organization. EPRINC was founded in 1944 and studies energy economics and policy issues with special emphasis on oil, natural gas, and petroleum product markets. I have worked on a broad range of energy security issues for my entire career, both in and out of government, beginning with the 1973-74 Arab oil embargo. For the last two years, EPRINC has undertaken a systematic assessment of challenges and opportunities of the energy transition which raise important challenges to the RFS program in the coming years.

Summary

EPRINC has undertaken research and analysis on the important role of biofuels in the transportation fuels sector since 2006, including a major workshop with the Energy Information Administration (EIA) as far back as 2008. From assessments starting in 2006, we have concluded that the principal drawbacks and risk factors of the program are not the use of biofuels as blendstock for gasoline and diesel fuel, but the statutory mandate which requires ever-larger blending volumes without regard to market conditions, costs or technical constraints. Biofuels represent an important contribution to U.S. energy security by expanding the supply of transportation fuels and large volumes of biofuels (mostly, corn-based ethanol) would be used to meet octane standards and local air pollution requirements even in the absence of blending mandates. However, price risks to consumers from higher transportation fuel costs rise substantially as mandates push biofuel blending above 10 percent of the gasoline pool. Today, the RFS program is raising gasoline prices by approximately 30 cents a gallon.

My testimony today includes (i) a brief historical background on the biofuel mandate, (ii) an assessment of the price risks from biofuel blending requirements under the RFS, (iii) the potential for escalating economic risks to consumers from the RFS program as the U.S. accelerates its efforts to move forward with the energy transition, and (iv) the importance of Congressional action to guide the program's goals and operations as EPA prepares for the 2023

reset under the statute.

Historical Background

Biofuels have long been used as blending components in U.S. transportation fuels to meet a wide variety of fuel specification and environmental requirements.[1] Prior to the recent resurgence in domestic oil and natural gas production, concerns about the U.S.' increasing dependence on imported oil led to the passage of both the Energy Policy Act of 2005 (EPAct05) and the Energy Independence and Security Act of 2007 (EISA). These laws established a broad program to blend renewable fuels into the domestic transportation fuel (gasoline and diesel) pools. These minimum volumes of ethanol and biomass-based diesel (biodiesel) were mandated to rise each year through 2022. At the time that the legislation was enacted, the blending requirements were viewed as being well below the bounds where they would create adverse operational effects. Furthermore, the RFS program was supposed to provide a cost-effective program to reduce petroleum imports as well as provide environmental benefits from a lower carbon fuel.[2]

EISA requires an increasingly aggressive program each year for blending biofuels with petroleum-based transportation fuels. Specifically, ethanol is blended into gasoline, and biodiesel is blended into diesel. These volumetric targets began in 2006 at a total of 260,000 barrels/day (4 billion gallons per year), and were mandated to rise to 2.35 million barrels/day (MBD) or 36 billion gallons per year (BGY) in 2022(Figure 1). However, due to a broad range of technical and cost concerns, EPA has routinely lowered volumetric requirements under provisions permitted by the statute. For 2022, the EPA is proposing to set the RVO for total renewable fuel

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[1] For a full discussion of fuel specifications, cost considerations, and regulatory requirements for manufacturing gasoline, see Pugliaresi, L., & Pyziur, M. (June 2015), ***Gasoline Blending: An EPRINC Primer***; http://eprinc.org/wp-content/uploads/2015/06/Updated-Gasoline-Primer-2015.pdf. Also, see Pugliaresi, L., & Pyziur, M. (November 2016), **The Biofuel Mandate: Technical Constraints and Cost Risks;** https://www.dropbox.com/s/6zldnd64svpl44h/Biofuel%20Mandate%20Nov%202015.pdf?dl=0**,** and Pugliaresi, L., & Pyziur, M. (February 2019), **OCTANE: Pathway to a Compromise**; https://eprinc.org/wp-content/uploads/2019/02/Octane-Pathway-to-a-Compromise-Feb-2019-FINAL.pdf.

[2] There is considerable debate on whether ethanol provides substantial environmental benefits from reduced GHG emissions When new land is brought into production lifecycle GHG emissions can increase. When these so-called indirect land use effects are ignored, ethanol can sometimes lower GHG emissions, but it can also add to deterioration in local air pollution. See Christopher W. Tessum, Jason D. Hill, and Julian D. Marshall**,** ***Life cycle air quality impacts of conventional and alternative light-duty transportation in the United States***. Proceedings of the National Academy of Sciences. See www.pnas.org/content/111/52/18490.full.pdf+html.

at 20.77 billion gallons, including 5.77 billion gallons of advanced biofuel, 2.76 billion gallons of biomass-based diesel, and 770 million gallons of cellulosic biofuel. The agency is also proposing to add a 250-million-gallon supplemental obligation and has stated its intent to add another 250-million-gallon supplemental obligation in 2023. The supplemental obligations would address the remand of the 2014-2016 annual rule by the D.C. Court of Appeals in Americans for Clean Energy v. EPA. The agency said spreading the obligation over two years would provide the market time to respond to the supplemental obligation.

One fundamental shift in U.S. petroleum outlook has changed dramatically since EISA became law. U.S. consumption of transportation fuels has declined instead of increased (Figure 2), and the U.S. Energy Information Agency (EIA) forecasts that demand for these fuels will continue this decline in the coming years. The reductions are considerable. For example, in 2022 as we recover from the pandemic, U.S. gasoline demand is likely to be at least 21 percent lower than projections made by EIA in 2007. This is important because volumetric targets are more difficult to achieve under lower demand conditions.

Price Risks to Consumers

A major problem with the program is that meeting the volumetric targets has become increasingly difficult (and costly) because of consumer resistance and technical constraints in achieving biofuel blends into the gasoline pool at percentages higher than 10%; this limitation is commonly known as the "blendwall." The introduction of gasoline blends at 15% (E-15) biofuel by volume has been helpful, but consumer resistance over performance and potential harm to combustion engines has constrained expansion of higher biofuel blends.

The RFS program is administered by requiring all refiners and importers (collectively known under the legislation as Obligated Parties) to document that they have acquired RINs (renewable identification numbers). In turn, these RINs are then acquired from biofuel producers by Obligated Parties registered with EPA, usually, when biofuels are blended into gasoline or diesel. In the early years of the program, the biofuel mandate, or RFS, could be met with so-called conventional biofuels (ethanol) blends below 10% of the gasoline pool. Refiners and other Obligated Parties could, however, blend above their mandated requirements and then retain those extra RINs for sale to Obligated Parties who had not met their mandates or bank them for use in the following year. In recent years, EPA has struggled with the program and has been

consistently late in setting the blending requirements for so-called obligated parties.

A key feature of the biofuel program is that as Obligated Parties are required to increase mandated biofuels above the blendwall, it becomes more likely that the mandates in the RFS will limit compliance options to a narrower set of high-cost strategies with elevated risks of price spikes in the cost of transportation fuels. The compliance program in the RFS operates under a general rule where Obligated Parties must fulfill each category of the RVO as well as the overall mandate. The RFS consists of categories corresponding to the different biofuel types. Compliance is complete when sufficient credits are obtained for each category, and sum to a targeted, required amount. RIN credits that are obtained in excess from blending themore advanced, expensive biofuels can be applied to fulfill compliance in the less advanced biofuel categories. However, the reverse is not allowed: excess credits from a less advanced biofuel cannot be applied to fulfill requirements in a more advanced biofuel category. For example, any renewable fuel that meets the requirement for cellulosic biofuels or biomass-based diesel (BBD) is also valid for meeting the advanced biofuels requirement. Thus, if any combination of cellulosic biofuels or BBD were to exceed their individual mandates, the surplus volume would count against the advanced biofuels mandate, thereby reducing the potential need for imported sugar-cane ethanol or other fuels to meet the unspecified portion of the advanced biofuels mandate.

Furthermore, any renewable fuel that meets the requirement for advanced biofuels is also valid for meeting the overall total renewable fuel requirement (which under the statute called for 36 BGY by 2022, but has been adjusted lower by EPA**).** As a result, any combination of cellulosic biofuels, BBD, or imported sugarcane ethanol that exceeds the advanced biofuel mandate would reduce the potential need for corn-derived ethanol to meet the overall mandate. The program does not permit covering the advanced requirements by using larger volumes of E85 or other corn-based biofuels. So Obligated Parties must meet both the overall RVO and also the individual categories, with the exception that exceeding the targets in the more advanced categories can be pushed to down to cover a lower category. By selecting a likely least-cost compliance, the RFS mandate fulfillment is initially done with those biofuel sources that exhibit some combination of lower cost and/or ease of implementation. To date, this has been primarily through the use of corn-based ethanol.

Modeling a range of likely compliance cost alternatives from 2017 to 2022 and viewing the

scenario with the adoption of the RFS mandate as outlined in EISA, EPRINC's calculations before this Committee in 2016 estimated that RVO obligations could increase gasoline prices from approximately 30 cents to 50 cents gallon. Actual data from December 2021 show that the RFS is now raising gasoline prices by nearly 30 cents per gallon (Figure 3). Other than the cost of crude oil (along with federal and state taxes), EPA's RVO targets is now an important component on the price of gasoline.

We understand that there has been in the past some disagreement, especially with EPA, on whether RIN prices are in fact driving up the price of gasoline. Figure 4 provides some additional perspective of this issue by showing recent changes in the crack spread. The crack spread (or margin) is the difference between the price of crude oil and the price of refined products, which include gasoline, distillates, diesel, and jet fuel. These so-called margins in processing crude oil into refined products (crack spread) include both a rate of return on installed capital for processing crude oil into transportation fuels as well as direct costs, of which RIN values are substantial and largely passed on to consumers. Two features shown in Figure 4 are worth noting. First, when small refiner exemptions (SREs) were given to disadvantaged processing facilities (especially in 2018 & 2019), the exemptions had the net effect of reducing system wide blending obligations and this lowered RIN costs. The elimination of the SREs had the net effect of rising system wide RVO costs. Whatever the merits of the SRE program it demonstrates that higher RVOs raise the cost of producing transportation fuels.

Figure 5 shows the recent run up in petroleum product prices as the world emerged from the pandemic and petroleum demand reverted to historical trends. For consumers, the cost of the RFS program was masked by lower oil prices, but as demand returned (and supply was unable to keep up) transportation fuel costs escalated. Part of the escalation in crude oil prices are clearly related to supply chain problems in getting new worldwide drilling operations underway to expand oil and gas production. Some commentators have also suggested that EPA's reset in 2023 should be used as an opportunity to move the program to a low carbon fuel standard that would be driven by more cost-effective criteria directly tied to reducing carbon emissions. As shown in the California case (Figure 6), while such a program would likely reduce some of the dislocations from the blending mandates, it does not eliminate rising costs from the production of transportation fuels.

Changing Market Conditions

The other important change from 2007 concerns over energy security is the remarkable expansion of domestic oil production from the technological revolution in exploration and production of crude oil from unconventional petroleum resources. The surge in crude oil production in the U.S., rising from 5 million barrels/day (MBD) in 2008 to over 12 MBD by 2020 (shown in Figure 7), has been a remarkable achievement of technological innovation and risk-taking in a province most analysts had suspected was undergoing permanent decline. Production suffered during the pandemic, but recovery is underway. After being written off as a petroleum province in permanent decline, the surge in U.S. production has not only reduced U.S. net imports, but made the country largely energy independent.

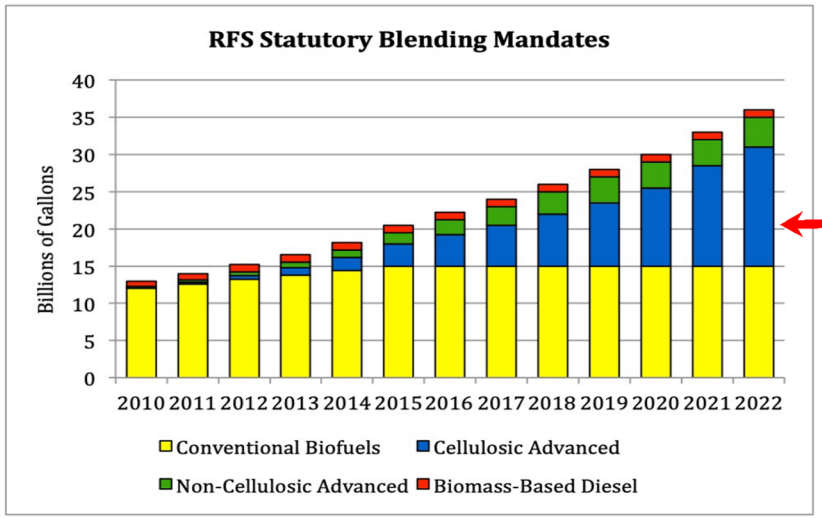
Even accounting for the production losses during the pandemic, the U.S. remains the largest oil and gas producer in the world. These domestic unconventional petroleum developments are altering flows in world crude oil trade and challenging the long-held conventional wisdom on U.S. energy policy that was promulgated in an era of scarcity. As shown in Figure 8, the U.S. provided over 80 percent of incremental worldwide liquids demand between 2010 and 2019. Without the expansion of the U.S., and the entire North American oil and gas production platform, crude oil prices in the U.S., and worldwide would have been substantially higher. In addition, as shown in Figure 9, we have little evidence that oil and gas reserves are stranded assets. If we want to protect U.S. energy security and consumers, we should continue to pursue policies which provide expanded opportunities for domestic oil and gas production. Many of the Administration current policies (halting crude oil & gas pipeline construction, sitting on permits for LNG exports, failure to proceed with offshore oil and gas leasing all pose large risks to U.S. energy security and consumers and create expectations in the marketplace that contribute to rising fuel prices. We should take great care in limiting U.S. oil and gas production before the energy transition is well underway

RFS Program and the 2023 Reset

We are heading into a largely uncharted world full of enormous price and energy security risks. We have an extraordinary responsibility to consider the entire array of risks and to develop

policies that are robust under uncertainties that cannot be easily predicted. Expect failures, cost over-runs and the unexpected. The reset is an opportunity to proceed with a program that both incorporates biofuels into our energy future, but does so in a manner that can adjust to the wide range of uncertainties. Congress should take this opportunity to shape the RFS program in a manner that can withstand a wide range of future challenges and opportunities going forward. Although EPA is required to proceed with the reset under a set of specific criteria, interpretation of the criteria is open to a very large set of alternative policies. In addition, other policies under consideration by the Administration, such as banning internal combustion engines and relying entirely on a future of only electric vehicles is inherently risky as we cannot predict how the technology will play out over time, or whether it will remain a cost-effective alternative for consumers. As shown in Figure 10, experienced analysts with long involvement in modeling our future energy requirements disagree on worldwide requirements over the next 30 years.

Figure 1
Cost and Technical Constraints Limit Adoption of Statutory Blending Mandates



EPA proposal for 2022 sets Renewable Fuel Obligation at 20.8 billion gallons year (BGY)

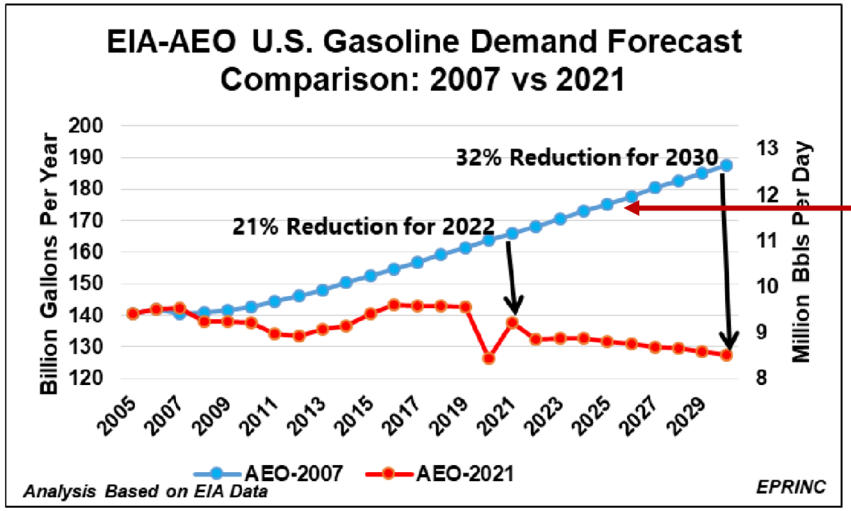
15 BGY (ethanol + biodiesel)
5.0 BGY (advanced)
0.8 BGY (cellulosic)

Program not meeting original statutory mandates Under EISA (2007)

61

Figure 2

2007 Energy Independence and Security Act (EISA) Expected Large Increases in Gasoline Demand

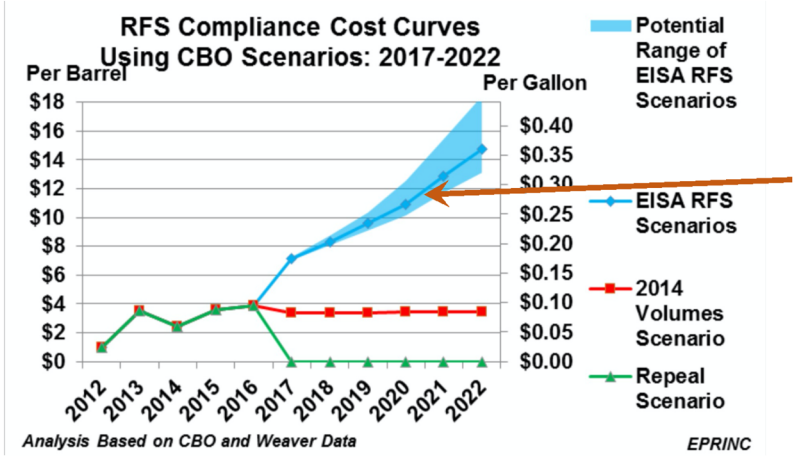


EISA biofuel mandates could have have been accommodated under EISA 2007 forecast at little or no cost

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Figure 3

EPRINC 2016 ANALYSIS OUTLINED COST RISKS FROM VOLUMETRIC TARGETS ABOVE THE BLEND WALL



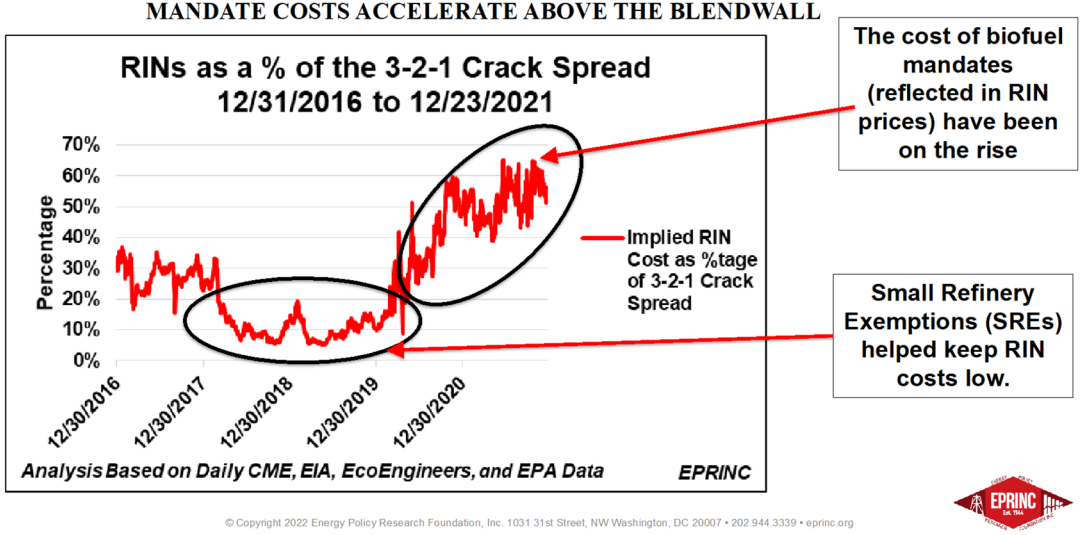
Program costs escalate as mandates drive volumes above the blend wall.

RFS program (*Dec 2021*) adding about 28 cents a gallon to price of gasoline

This tracks current cost increases in production of transportation fuels (as shown in "crack spreads")

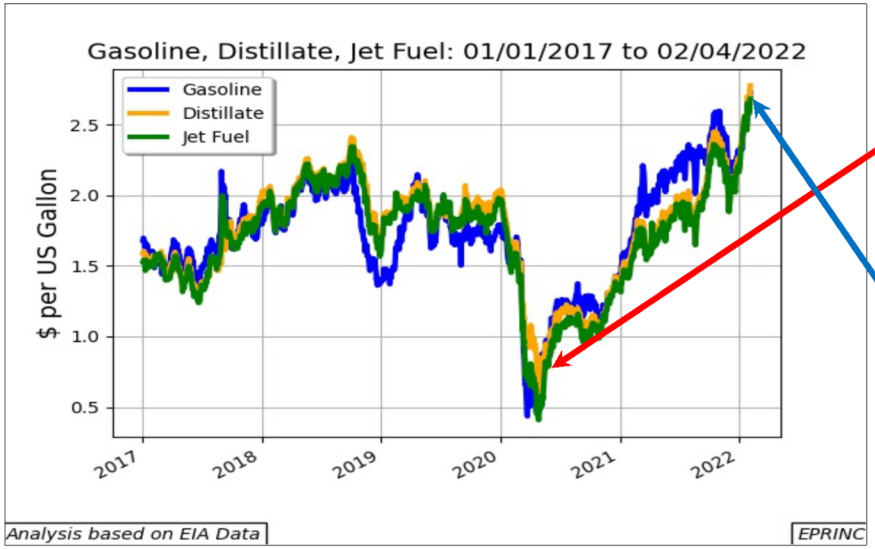
Figure 4

PRODUCTION COST OF GASOLINE AND DIESEL FUEL ARE RISING BECAUSE RFS MANDATE COSTS ACCELERATE ABOVE THE BLENDWALL



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Figure 5 **ERA OF LOWER CRUDE AND PRODUCT PRICES MAY BE OVER**

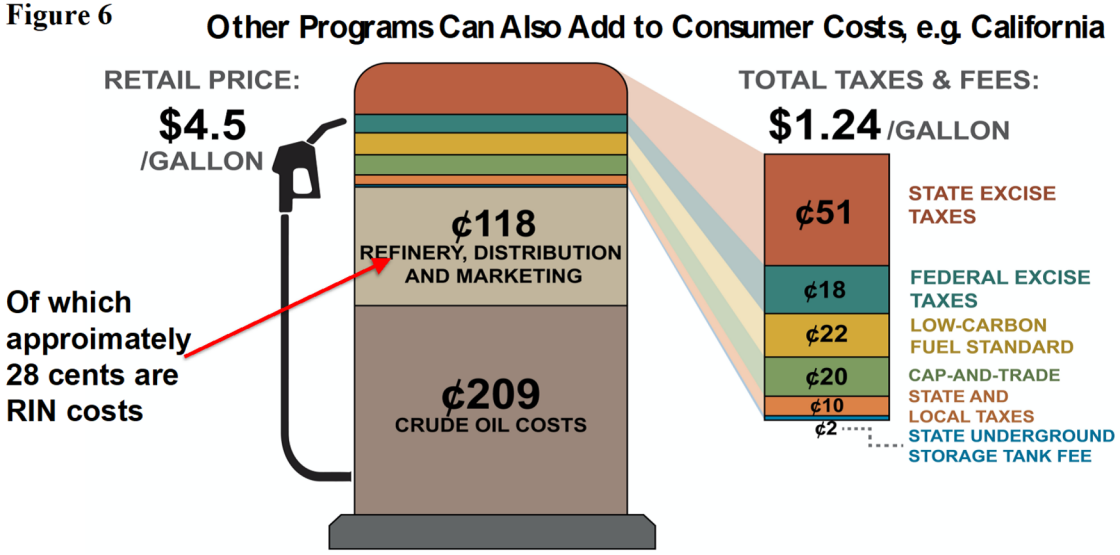


Lower fuel prices (from lower crude costs) masked the cost of the regulatory programs

Higher prices may be around for a long time as the world recovers from the pandemic and both government regulatory policies & ESG policies/initiatives have limited investment in legacy fuels

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Figure 6



Price data as of January 17, 2022; Low-Carbon Fuel Standard and Cap-and-Trade data as of September 2021
Source: EPRINC figure based on data from the California Energy Commission and WSPA

Figure 7

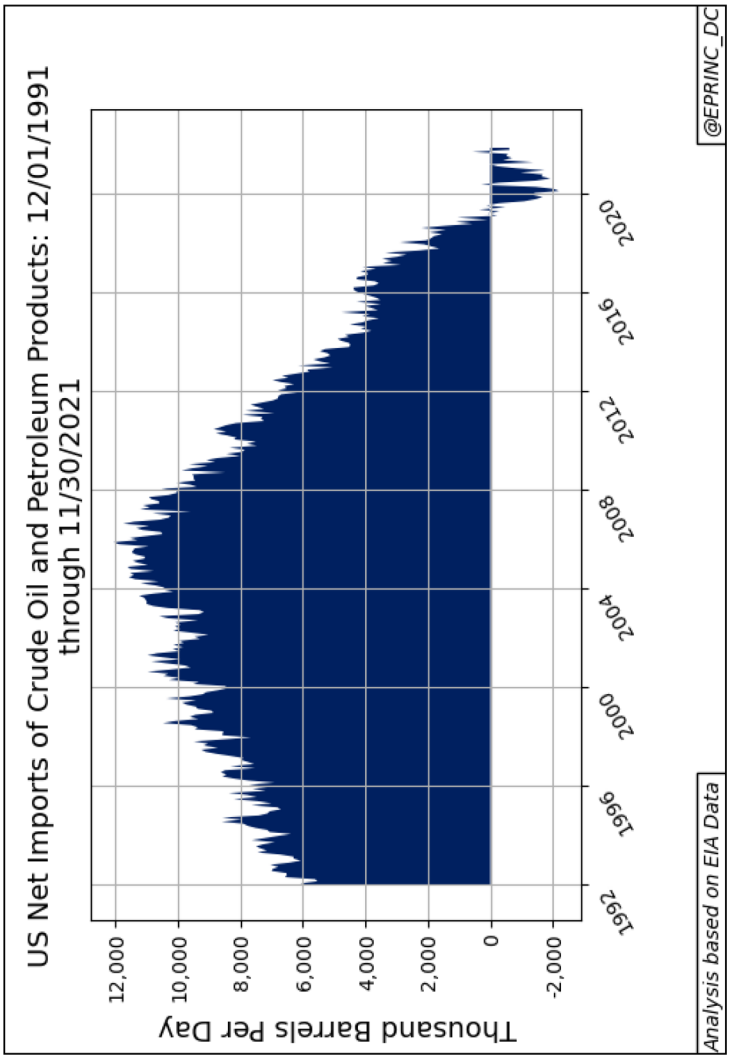
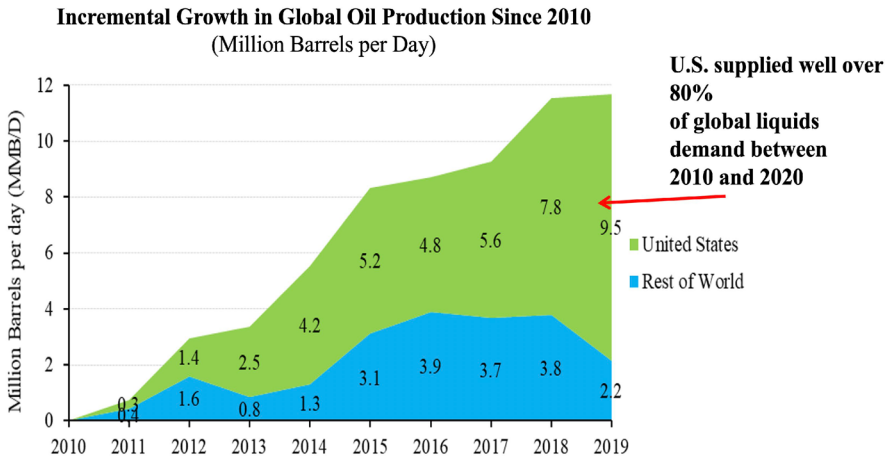
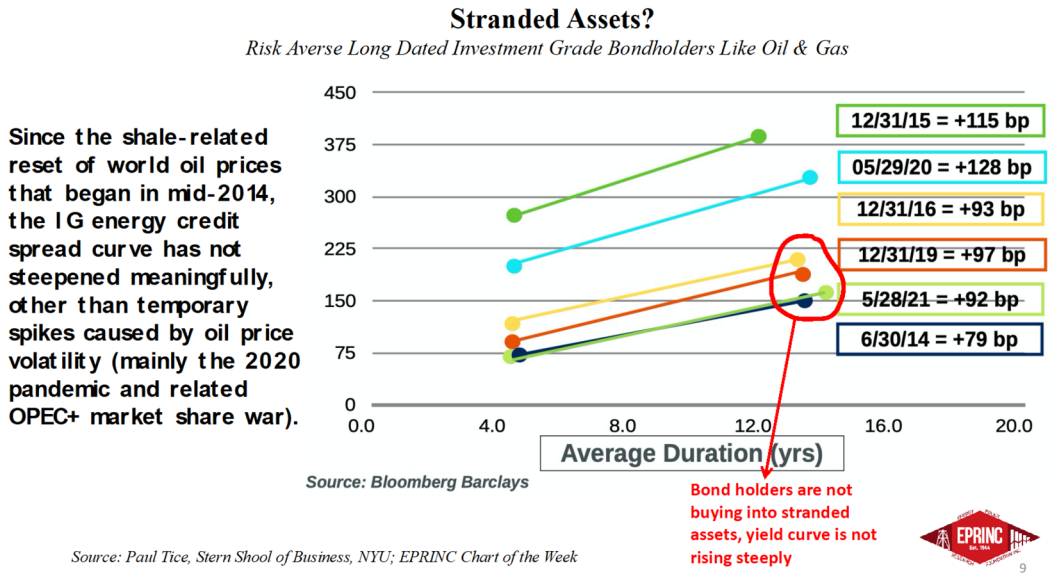

US Net Imports of Crude Oil and Petroleum Products: 12/01/1991 through 11/30/2021
Thousand Barrels Per Day
12,000
10,000
8,000
6,000
4,000
2,000
0
-2,000
1992
1996
2000
2004
2008
2012
2016
2020
Analysis based on EIA Data
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Figure 8



Source: EPRINC figure based on data from BP Statistical Review of World Energy 2021

Figure 9



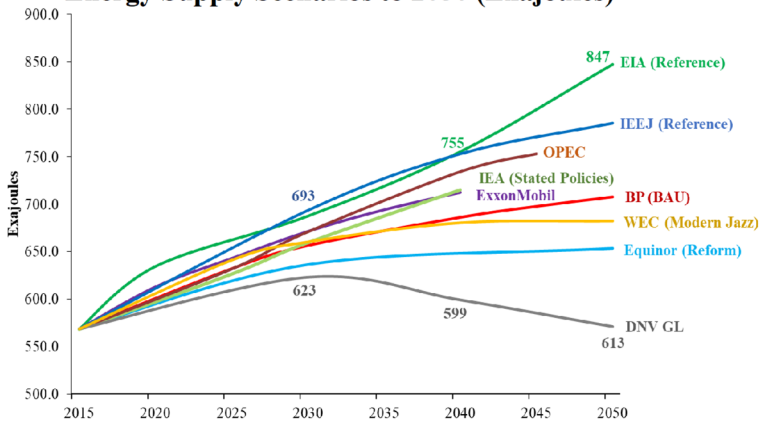
Source: Paul Tice, Stern Shool of Business, NYU; EPRINC Chart of the Week

Figure 10

US Energy Policy Should be Robust Against Uncertainty

Energy Supply Scenarios to 2050 (Exajoules)

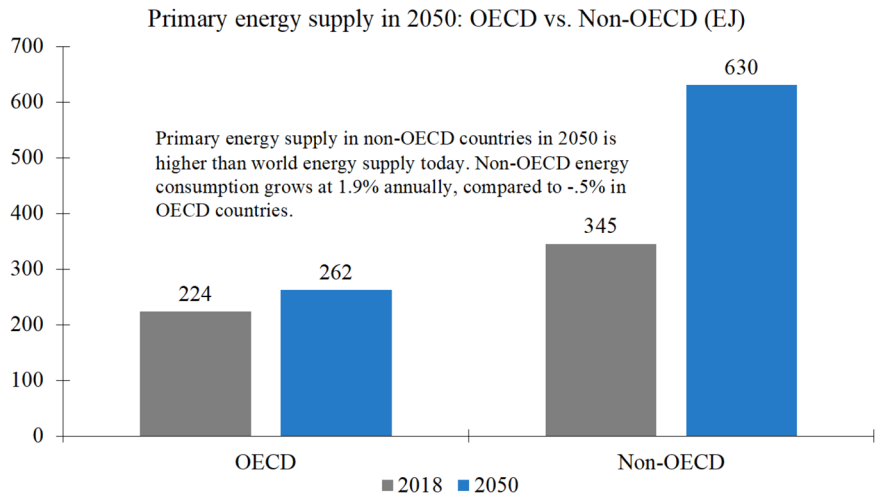
How do you explain the wide differences in outlooks?



Note: Exajoule (EJ) is a comprehensive unit of energy, roughly equivalent to 1.05 quadrillion British thermal units (quads). One EJ equals 10^{18} (one quintillion) joules, and one joule equals the amount of work done on a body by a 1 Newton force that moves the body over 1 meter. One exajoule per year = 447,000 barrels of oil equivalent per day.

Additional Information
On Long Term Price Risks for
Petroleum Products & EVs

Figure 11 **Non-OECD Will Drive 88% of Global Energy Growth Through 2050**



Source: EPRINC analysis and projections based on historical data from IEA World Energy Balance

Figure 12

Even If OECD Approaches Net Zero, Non-OECD Will Struggle to Follow Suit

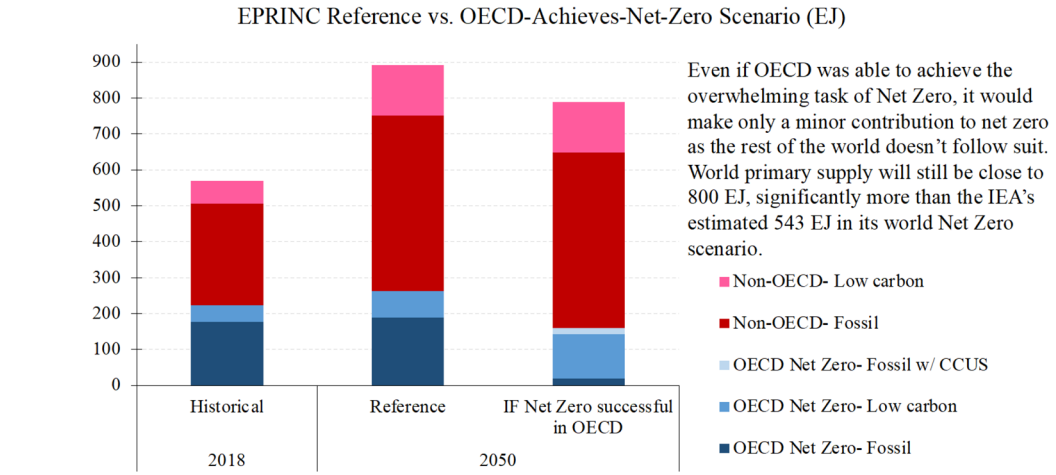
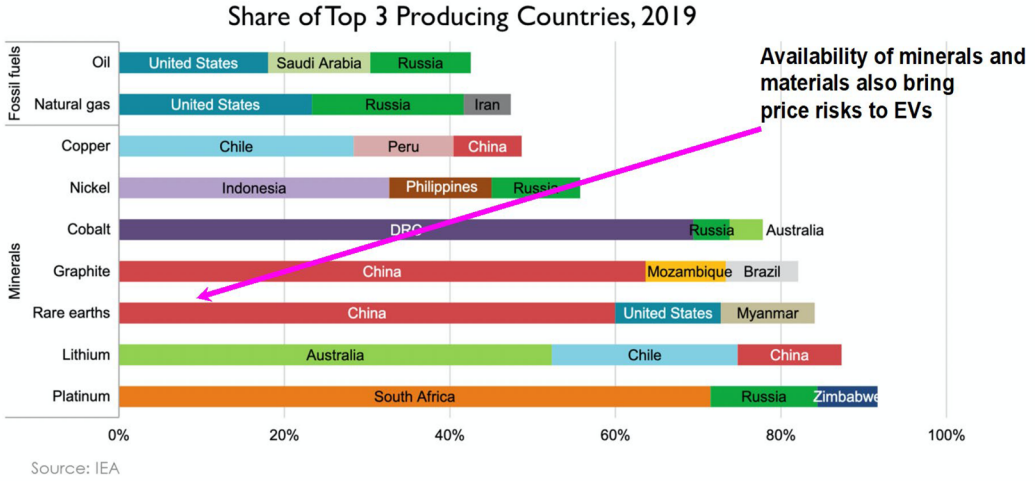


Figure 13

The U.S. is a Leader in Oil and Gas Production

(In specialty minerals, the U.S. is highly dependent on foreign sources of supply)



Source: IEA

FIGURE 14

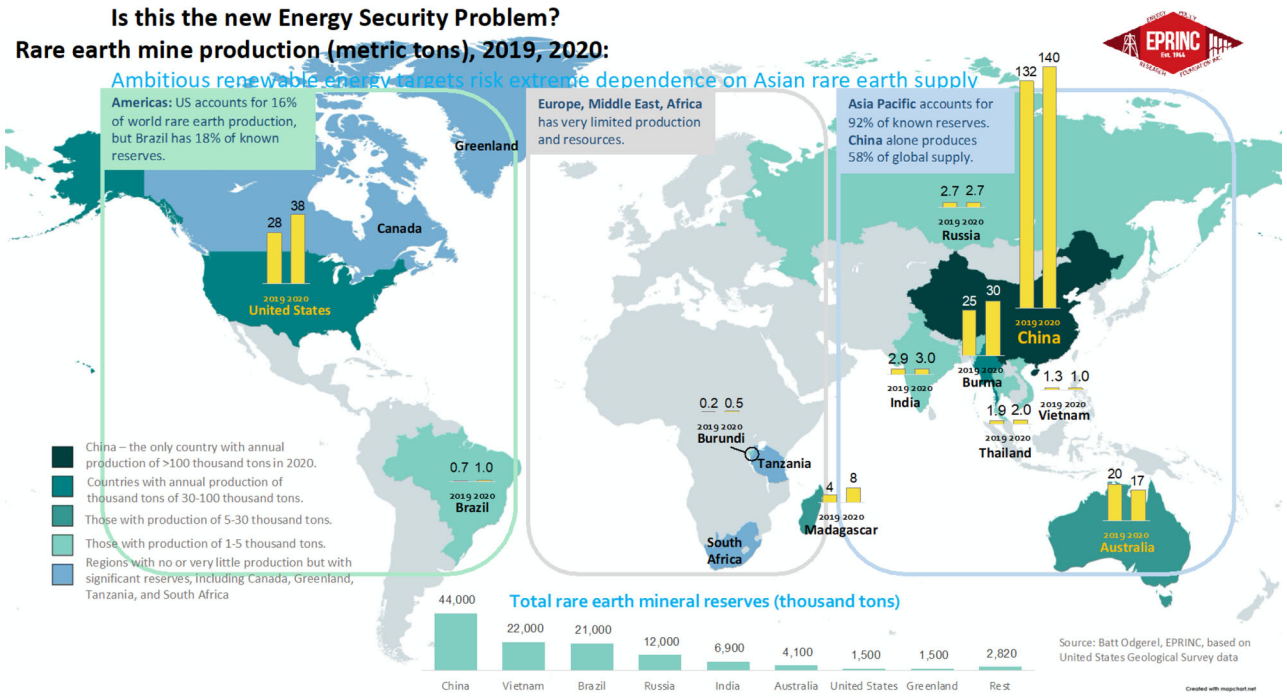
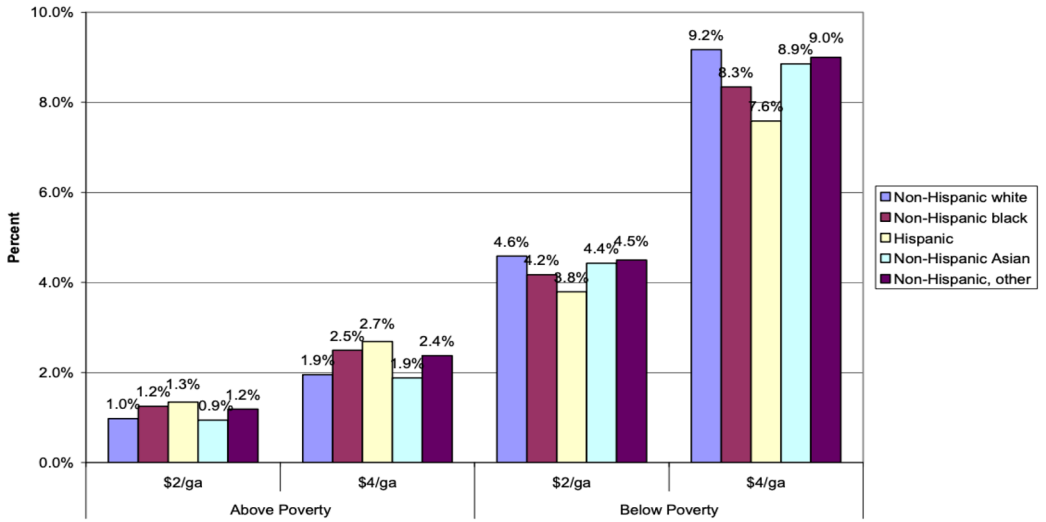

Is this the new Energy Security Problem?
Rare earth mine production (metric tons), 2019, 2020:
Ambitious renewable energy targets risk extreme dependence on Asian rare earth supply
EPRINC
Americas: US accounts for 16% of world rare earth production, but Brazil has 18% of known reserves.
Europe, Middle East, Africa has very limited production and resources.
Asia Pacific accounts for 92% of known reserves. China alone produces 58% of global supply.
Greenland
Canada
28 38
2019 2020
United States
0.7 1.0
2019 2020
Brazil
0.2 0.5
2019 2020
Burundi
Tanzania
South Africa
4 8
2019 2020
Madagascar
2.7 2.7
2019 2020
Russia
132 140
25 30
2019 2020
China
2.9 3.0
2019 2020
India
2019 2020
Burma
1.3 1.0
2019 2020
Vietnam
1.9 2.0
2019 2020
Thailand
20 17
2019 2020
Australia
China – the only country with annual production of >100 thousand tons in 2020.
Countries with annual production of thousand tons of 30-100 thousand tons.
Those with production of 5-30 thousand tons.
Those with production of 1-5 thousand tons.
Regions with no or very little production but with significant reserves, including Canada, Greenland, Tanzania, and South Africa
Total rare earth mineral reserves (thousand tons)
44,000
22,000
21,000
12,000
6,900
4,100
1,500
1,500
2,820
China
Vietnam
Brazil
Russia
India
Australia
United States
Greenland
Rest
Source: Batt Odgerel, EPRINC, based on United States Geological Survey data
Created with mapchart.net

FIGURE 15

Rising Cost of Transportation Fuels Harm Low-Income and Many Minority Communities



Source: Urban Institute

U.S. Senate Committee on Environment and Public Works

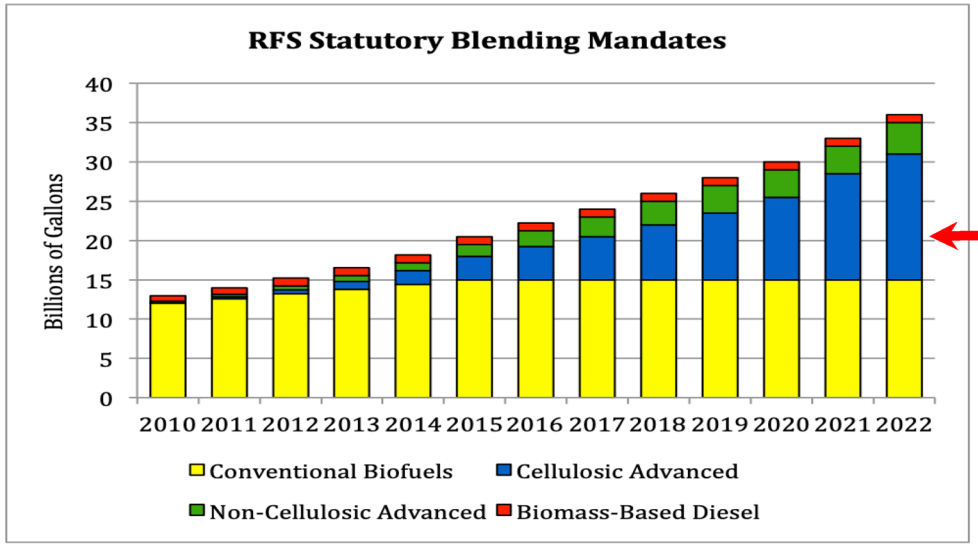
Charts for Summary of Testimony for Hearing

The Environmental Protection Agency's Renewal Fuel Standard program

February 16, 2022
10:00 AM
Dirksen Senate Office Building (Room 406)

Lucian Pugliaresi
Energy Policy Research Foundation, Inc. (EPRINC)
1031 31st Street NW
Washington, DC 20007
eprinc.org

Figure 1
Cost and Technical Constraints Limit Adoption of Statutory Blending Mandates



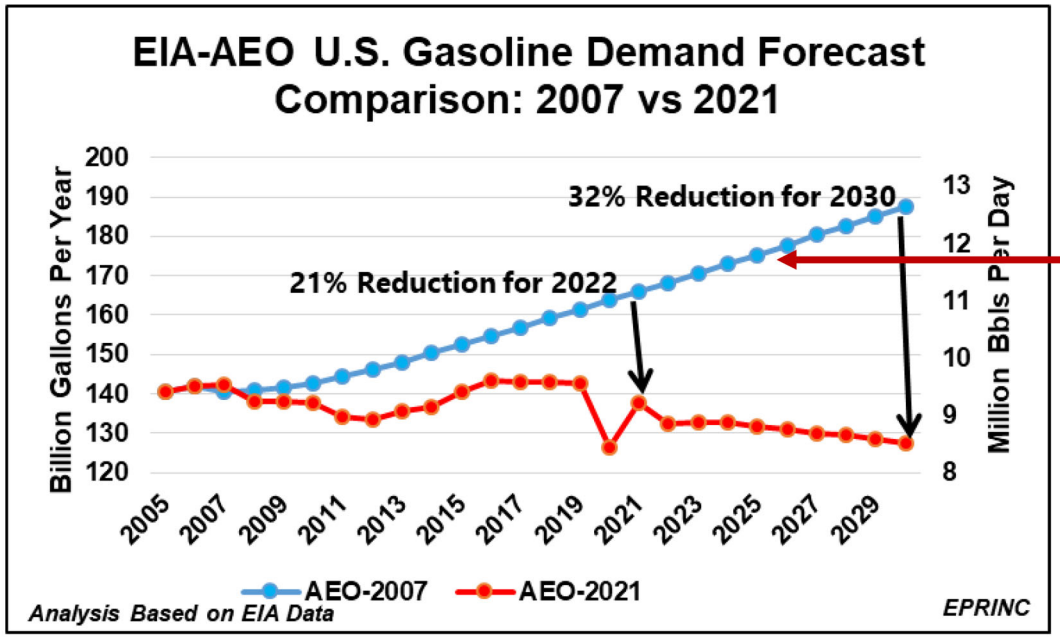
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15 BGY (ethanol + biodiesel)
5.0 BGY (advanced)
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Program not meeting original statutory mandates Under EISA (2007)

Figure 2

2007 Energy Independence and Security Act (EISA) Expected Large Increases in Gasoline Demand

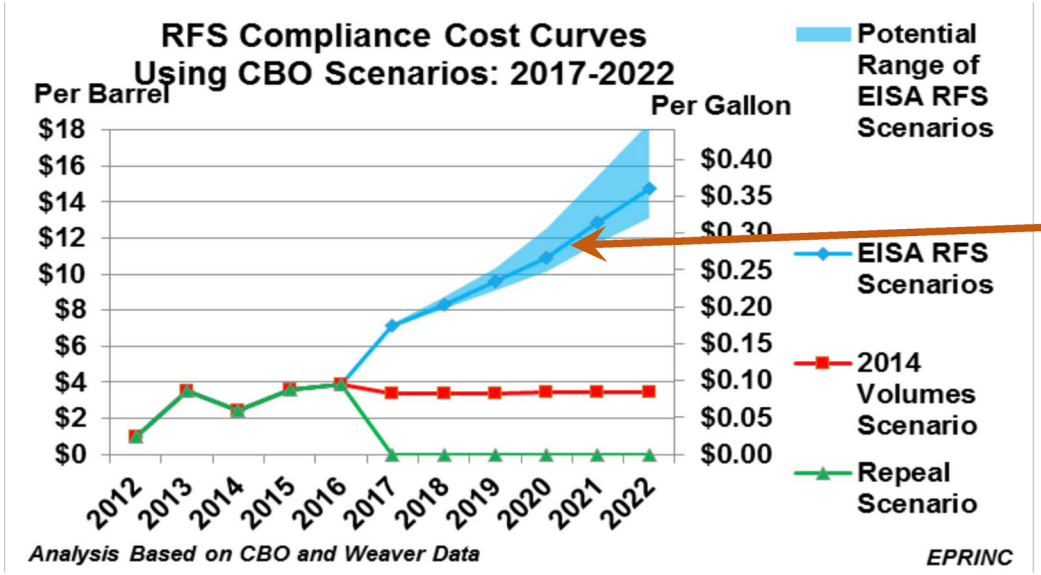


EISA biofuel mandates could have have been accommodated under EISA 2007 forecast at little or no cost

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Figure 3

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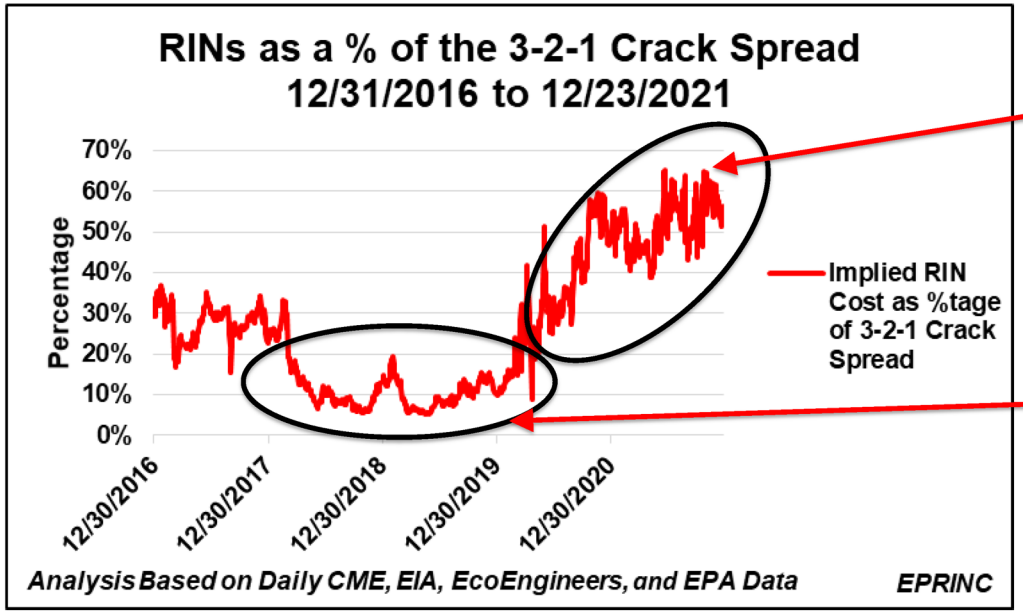
Program costs escalate as mandates drive volumes above the blend wall.

RFS program (*Dec 2021*) adding about 28 cents a gallon to price of gasoline

This tracks current cost increases in production of transportation fuels (as shown in ”crack spreads”)

Figure 4

PRODUCTION COST OF GASOLINE AND DIESEL FUEL ARE RISING BECAUSE RFS MANDATE COSTS ACCELERATE ABOVE THE BLENDWALL

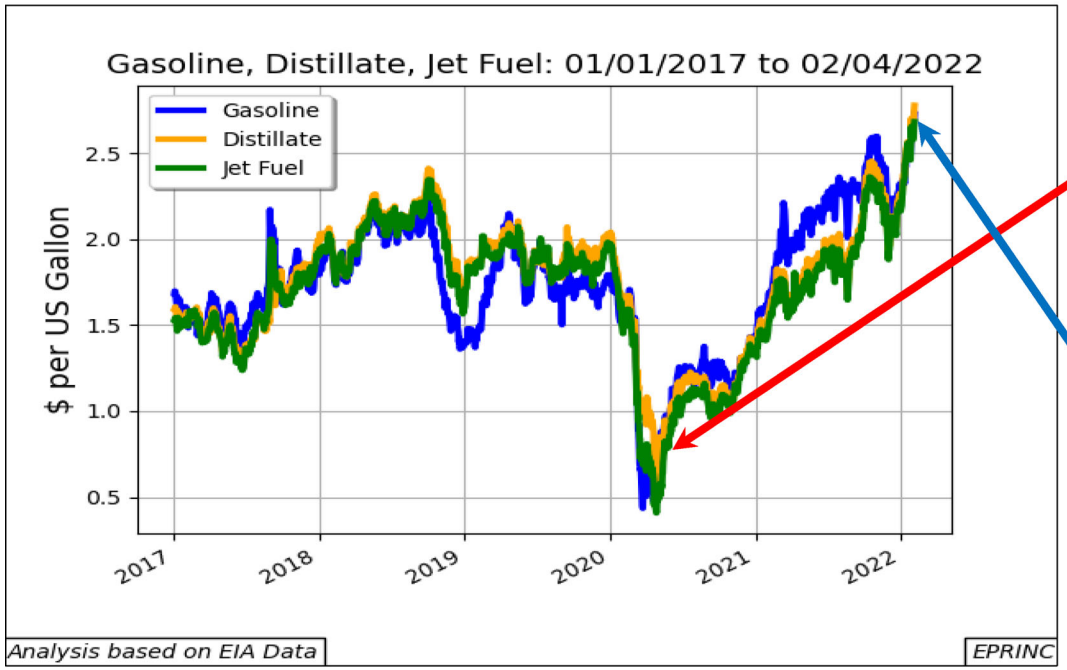


The cost of biofuel mandates (reflected in RIN prices) have been on the rise

Small Refinery Exemptions (SREs) helped keep RIN costs low.

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Figure 5 **ERA OF LOWER CRUDE AND PRODUCT PRICES MAY BE OVER**

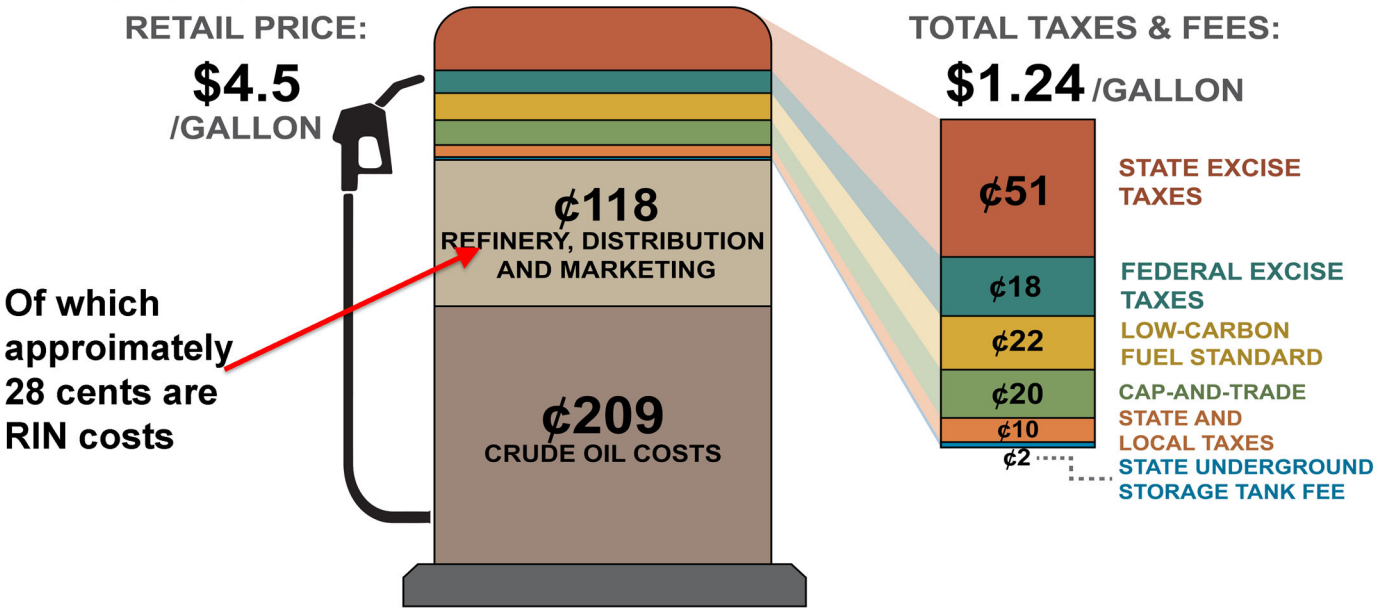


Lower fuel prices (from lower crude costs) masked the cost of the regulatory programs

Higher prices may be around for a long time as the world recovers from the pandemic and both government regulatory policies & ESG policies/initiatives have limited investment in legacy fuels

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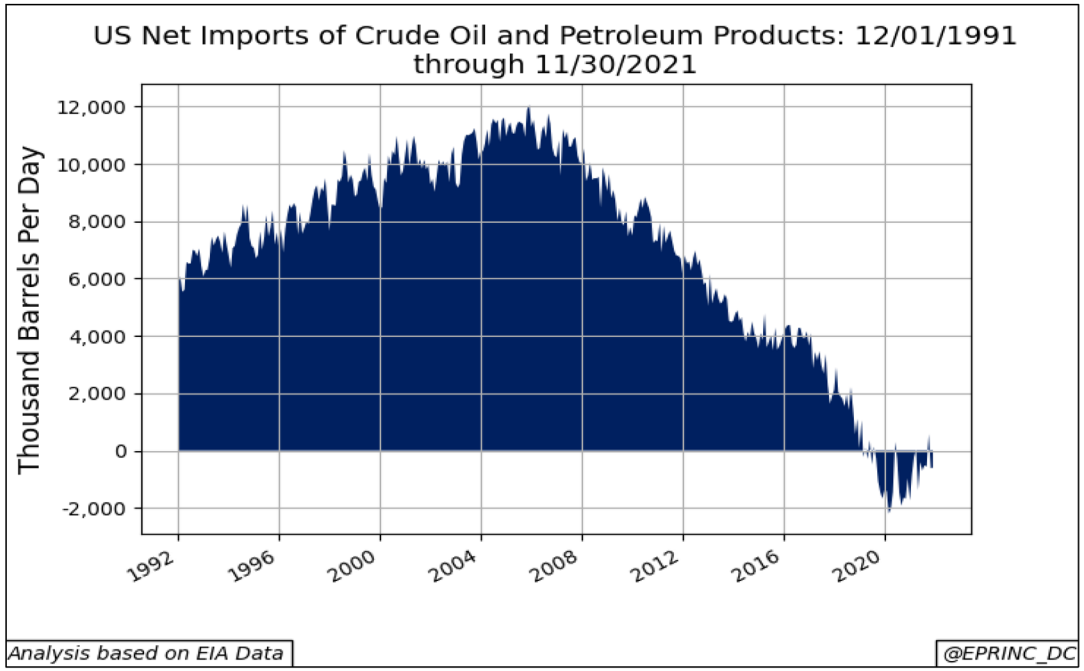
Figure 6 **Other Programs Can Also Add to Consumer Costs, e.g. California**



Price data as of January 17, 2022; Low-Carbon Fuel Standard and Cap-and-Trade data as of September 2021
Source: EPRINC figure based on data from the California Energy Commission and WSPA

Figure 7

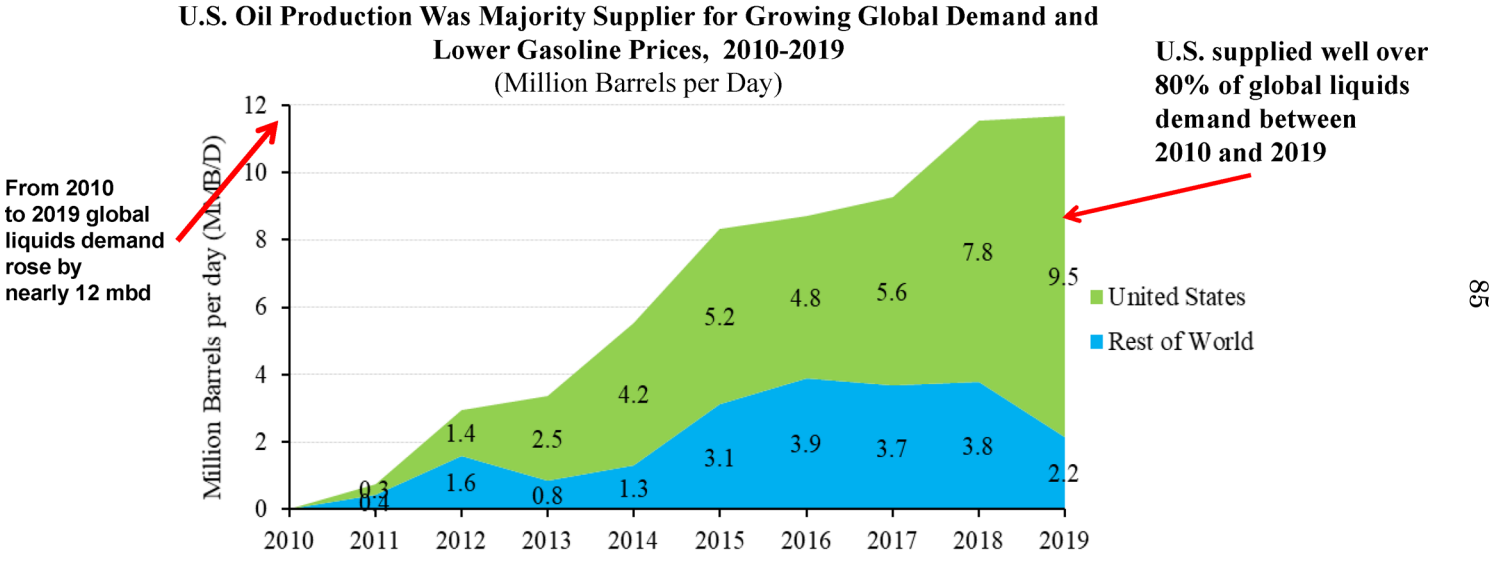
Surge in US Oil Production (+ Biofuels) Made US Energy Independent



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Figure 8

In the Absence of U.S. Production Growth, Crude Oil Prices Would Have Spiked Earlier



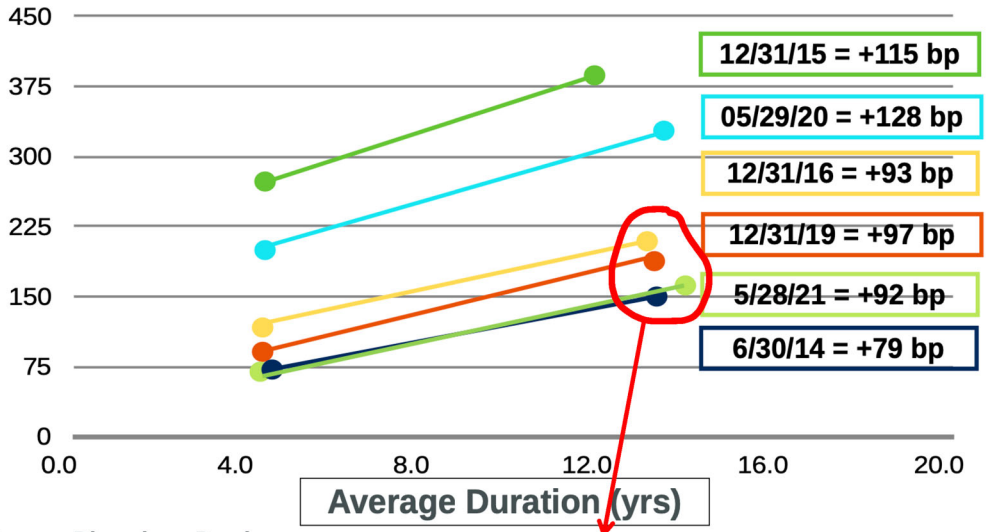
Source: EPRINC figure based on data from BP Statistical Review of World Energy 2021

Figure 9

Stranded Assets?

Risk Averse Long Dated Investment Grade Bondholders Like Oil & Gas

Since the shale-related reset of world oil prices that began in mid-2014, the IG energy credit spread curve has not steepened meaningfully, other than temporary spikes caused by oil price volatility (mainly the 2020 pandemic and related OPEC+ market share war).

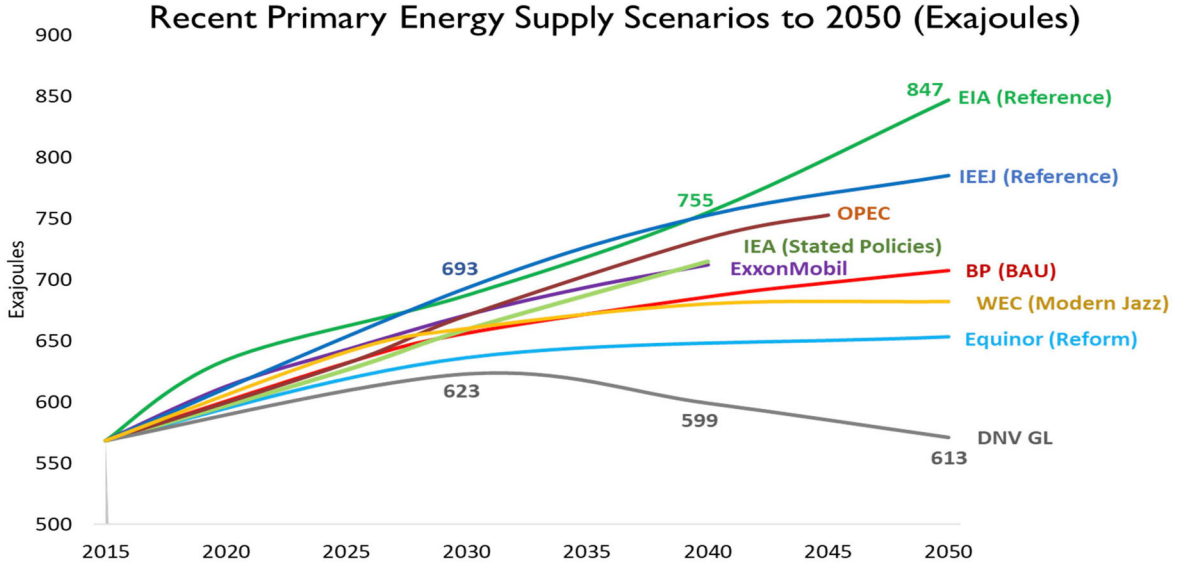


Source: Bloomberg Barclays

Source: Paul Tice, Stern Shool of Business, NYU; EPRINC Chart of the Week

Figure 10

Wide Differences in Energy Outlooks

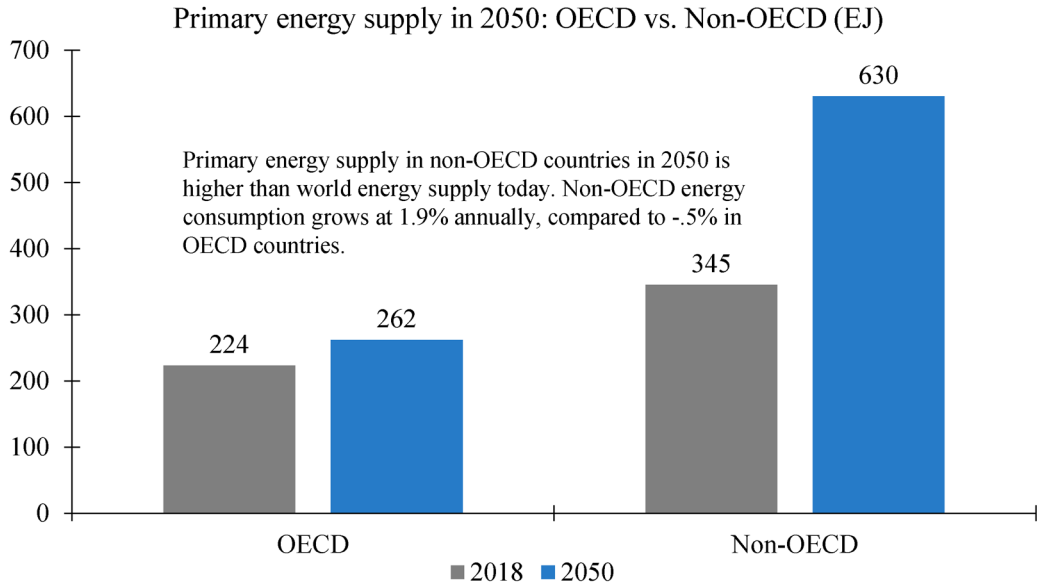


Note: Exajoule (EJ) is a comprehensive unit of energy, roughly equivalent to 1.05 quadrillion British thermal units (Quads). One EJ equals 1018 (one quintillion) joules, and one joule equals the amount of work done on a body by a 1 Newton force that moves the body over 1 meter. One EJ per year = 447,000 barrels of oil equivalent per day.

Source: EPRINC analysis and figure based on outlooks by the nine groups

Additional Information
On Long Term Price Risks for
Petroleum Products & EVs

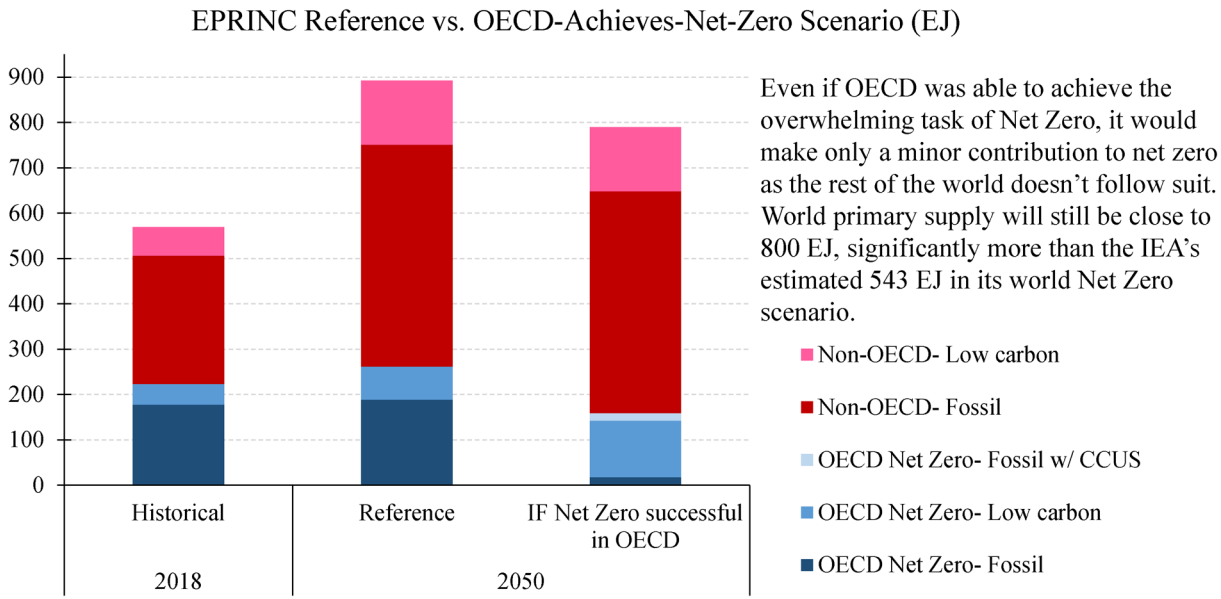
Figure 11 **Non-OECD Will Drive 88% of Global Energy Growth Through 2050**



Source: EPRINC analysis and projections based on historical data from IEA World Energy Balance

Figure 12

Even If OECD Approaches Net Zero, Non-OECD Will Struggle to Follow Suit

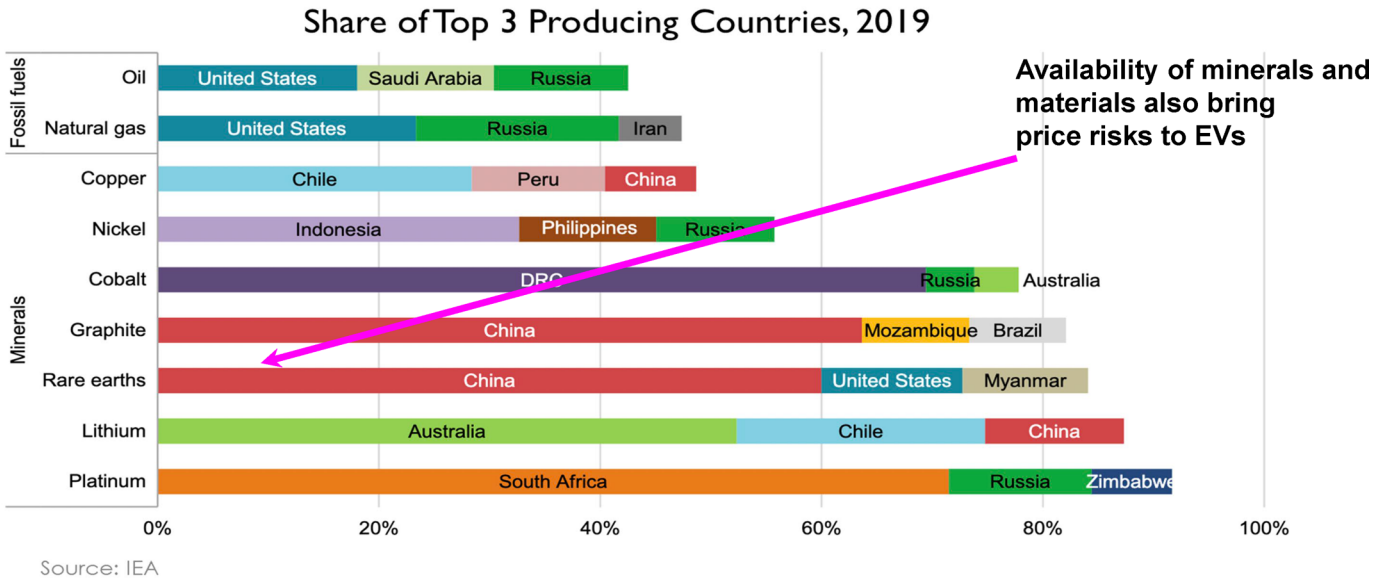


Even if OECD was able to achieve the overwhelming task of Net Zero, it would make only a minor contribution to net zero as the rest of the world doesn't follow suit. World primary supply will still be close to 800 EJ, significantly more than the IEA's estimated 543 EJ in its world Net Zero scenario.

Figure 13

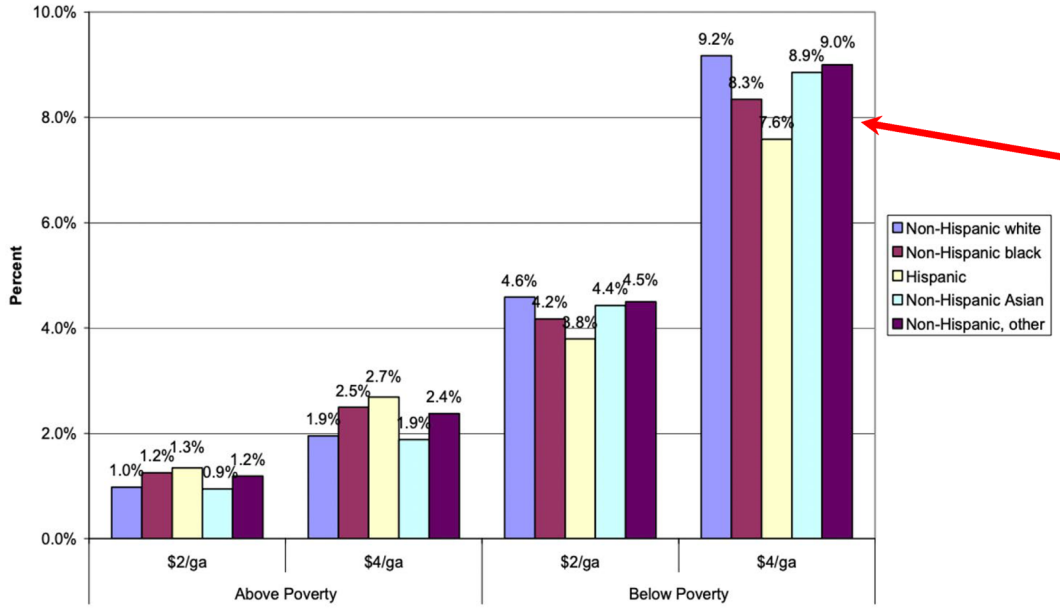
The U.S. is a Leader in Oil and Gas Production

(In specialty minerals, the U.S. is highly dependent on foreign sources of supply)



Source: IEA

Higher Gasoline Prices Harm Low-Income and Minority Communities



U.S. energy policies which seek to curtail the production of legacy fuels without adequate low-cost substitutes are especially harmful to low-income and minority communities

Source: *Impact of Rising Gas Prices on Below-Poverty Commuters,* Urban Institute. **Fact Sheet from the Low-Income Working Families Project September 2008.** https://www.urban.org/sites/default/files/publication/32031/411760-Impact-of-Rising-Gas-Prices-on-Below-Poverty-Commuters.PDF

AUTO EMISSIONS THEN & NOW



Steve McQueen, a San Francisco detective in the iconic thriller, ***Bullitt,*** chases the bad guys in his 1968 Ford Mustang GT fastback

1968 Mustang, 1500 pounds to 1 ton of criteria pollutants per 100,000 miles*

2016 Mustang, 10-20 pounds of criteria pollutants per 100,000 miles

Note: *Criteria pollutants: The Clean Air Act requires EPA to set National Ambient Air Quality Standards maximum allowable concentrations of six "criteria" pollutants in outdoor air. The six pollutants are carbon monoxide, lead, ground-level ozone, nitrogen dioxide, particulate matter, and sulfur dioxide. Calculations of emissions for each model year were based on official EPA data

March 17, 2022

Questions for the Record

Senate Committee on Environment and Public Works

"The Environmental Protection Agency's Renewable Fuel Standard Program: Challenges and Opportunities"

Hearing Date: February 16, 2022

Responses Provided by

Lucian Pugliaresi, President, Energy Policy Research Foundation, Inc. (EPRINC)

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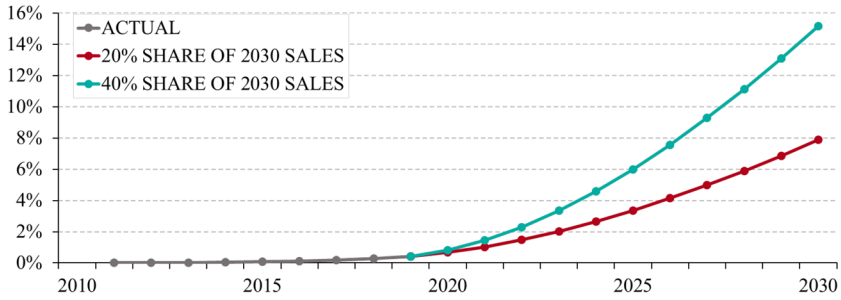
Ranking Member Capito:

1. ***How important are liquid fuels?***

Vehicle life has greatly increased in recent decades, and the slow turnover means that even if battery electric vehicles (BEVs) make up 40% of new car sales in 2030, the share of the vehicle stock will be less than 16% (Figure 1). Even with robust BEV sales and miles driven matching that of internal combustion engines (ICE) vehicles, oil demand in 2030 will only decline by 15% or 10.6 mb/d compared to stated policies scenarios of the International Energy Agency. With auto sales growth of 2.8% per year, auto stock grows by 40% from 2019 to 2030. Assuming constant miles driven and vehicle efficiency, demand would rise from 52 million barrels/day (mb/d) to 70 mb/d. If BEV sales are 20% of total auto sales in 2030, and vehicle miles are equal to ICE vehicles, demand is reduced by 7.9% or 5.5 mb/d. If BEV sales are 40% of total auto sales in 2030, and vehicle miles are equal to ICE vehicles, demand is reduced by 15.2% or 10.6 mb/d. Even in this optimistic scenario of the use of BEVs liquid fuels remain essential for modern transportation systems.

Figure 1

Worldwide Battery Electric Vehicle Share of Auto Stock (%)



Source: Strategic Energy and Economic Research, Energy Policy Research Foundation, Inc.

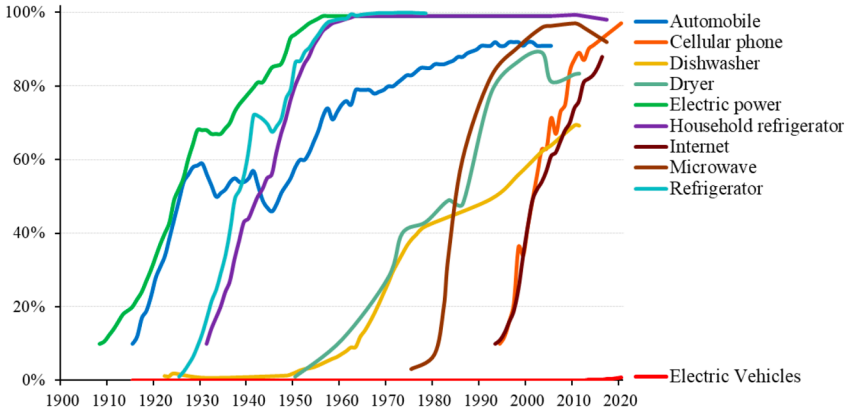
a. ***Do you think liquid fuels are going away anytime soon?***

Although the market share of BEVs (in new vehicle sales) remains at 2% globally, most forecasts see significant increases in the next ten years and beyond. The optimism about battery electric vehicles stems partly from the necessity of decarbonizing transport. The technology used, specifically lithium-ion batteries, has greatly improved in recent years, and optimists point to rising sales and automakers point to aggressive production plans, including many announced models, although most have not yet been produced. However, electric vehicles remain much

more expensive than conventional internal combustion engines (ICEs); BEV sales are still dominated by luxury vehicles and early adopters. While the range of BEVs has improved, most models' claimed range represents optimal conditions and actual ranges tend to be much lower. There is still a need for major investments in charging stations and related infrastructure, and intangibles, most notably the greater inconvenience of BEVs, represent both an uncertainty and a hurdle to greater market share. As shown in Figure 2 below, liquid fuels will be a major part of modern transportation for decades for both the U.S. and worldwide. For U.S. energy policy to ensure resilience against expensive and insecure imports we will need to sustain domestic production of domestic oil and gas resources.

Figure 2

Share of U.S. Households Using Specific Technologies, 1990-2020



Source: EPRINC figure based on data from the IEA Global EV Outlook 2021, U.S. Bureau of Transportation Statistics, and Comin & Hobijn and other (ourworldindata.org)

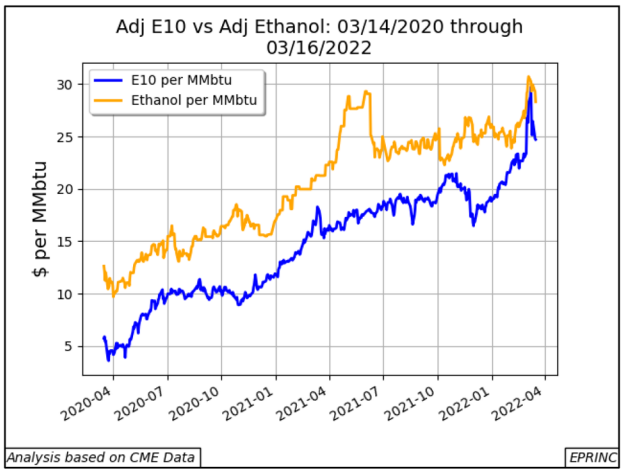
2. ***Ethanol proponents argue that higher ethanol blends, such as E15, sell for lower prices relative to a gallon of E10 and a gallon of E15 have the same energy density?***

A gallon of ethanol has about 70 percent of the density of a gallon of gasoline (E0). As more ethanol is added to the gasoline pool, mileage performance declines; by about 7% when using E10 and about 10.5% when using E15.

a. Is ethanol more or less energy dense than gasoline?

As discussed above and shown in Figure 3 below, the lower density of ethanol provides less value (more expensive in terms of energy delivered).

Figure 3
Ethanol's Lower Energy Density Generally Leads to Less Value per Million BTUs (MMbtu)



b. Does the energy density of a gallon of gasoline impact a vehicle's average fuel economy in miles per gallon (MPG)?

Yes, the more ethanol added to gasoline the lower the mileage. Each ten percent increment of ethanol blended into gasoline lowers mileage performance by about 7%.

c. How does the energy density of a particular fuel affect what consumers receive for their money at the pump at a given price? Put another way, is a claim that a gallon of E15 is "cheaper" than a gallon of E10 at retail a true apples-to-apples comparison if one also considers factors like energy density, fuel economy, wear and tear on mechanical components, or other differences between the two fuels.

Blending ethanol into gasoline can provide value as both a fuel extender and a low-cost method to boost octane. For ethanol blended into the gasoline pool at volumes of 10% or lower, ethanol can provide value to consumers be delivering low-cost octane. Depending on the cost of ethanol (tied to cost of corn) this is now the preferred and low-cost method of meeting octane standards for gasoline. Octane is important for preventing engine knocking, so-called pre-ignition. Cost escalation for consumers occurs when federal mandates require blending of ethanol into the gasoline pool above 10%. EPRINC research shows that these higher blend volumes have raised the compliance costs of meeting the mandate by about 30 cents a gallon. Consumer resistance and technical constraints raises the overall costs for the gasoline pool that would not occur absent the volumetric mandate. This is because the RFS mandate closes off alternative and more cost-effective processes for producing gasoline.

3. **The 117th Congress is considering several energy tax provisions. Among these are enhanced tax credits for various kinds of alternative fuels and advanced biofuels, including for sustainable aviation fuel. Do you have any concerns that more favorable tax treatment for subcategories like sustainable aviation fuel may have unintended consequences for other types of transportation fuels, such as biodiesel and renewable diesel, that compete for the same input feedstocks?**

As stated above, U.S. policies which rely upon mandates rather than traditional market forces are likely to have a broad range of unintended consequences. Some biofuels are expensive to produce and subsidizing their use can add rising costs for national biofuel production. This is especially true for bio-diesel fuels which are expensive to produce, are an essential and costly component for meeting RFS requirements and are likely to see escalating cost increases adding to inflation at grocery stores and fuel stations. Tax provisions and related legislation authorizing the expansion of biofuels into fuel categories, such as sustainable aviation fuels, should not proceed with careful assessment of cost-escalation consequences.

   a. **What potential implications do these sorts of preferential policies have for supply and demand of other biofuels, prices for consumers buying these fuels, as well as the broader transportation fuel sector's ability to meet requirements under the RFS.**

These preferential policies will spill over into the production of other biofuels, contributing to inflation in both the ground transportation sector and for food.

Senator Inhofe:

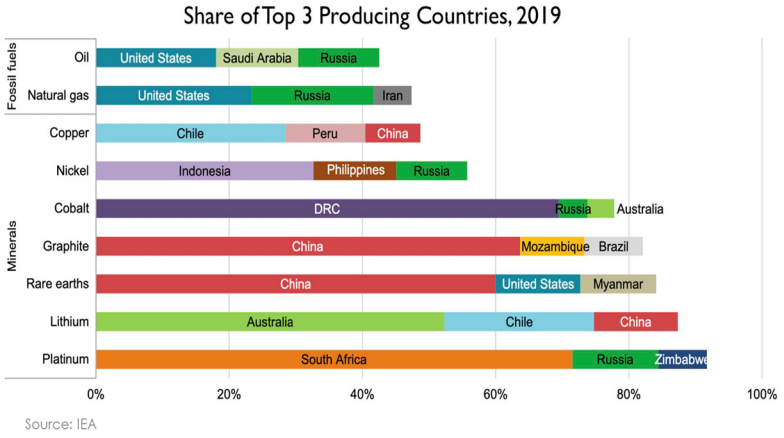
1. **Mr. Pugliaresi, I have long been concerned with the growing threat adversaries like China pose to America's national security. It's important to remember that China controls well over half of all the critical mineral mining and processing for the world and these resources are vital to the manufacturing of electric vehicles. I'm concerned that calls to mandate the electrification of the transportation would increase our reliance on China for critical minerals. Do you believe the U.S. should expand domestic mining of critical minerals so that we can lessen our reliance on China and other foreign nations for critical minerals used in electric vehicle manufacturing?**

It is essential the U.S. proceed with expansion and development of domestic mining and processing of critical minerals, especially for the production of electric vehicles and other renewable technologies that rely upon these minerals. However, we have to be realistic about the pace at which we can develop critical minerals and materials in the domestic market. Today, the U.S. is the largest producer of oil and gas worldwide. This provides strategic advantages and energy independence. A rapid shift to reliance on electric vehicles (and batteries), solar, wind and related renewable energy sources will also require large quantities of copper, lithium, manganese, cobalt, and molybdenum. While many of these minerals can be developed through potential mining sites in the U.S., these minerals will also require new processing facilities to be developed into useable materials. Permitting constraints and environmental reviews will likely make the development of these resources a long and arduous effort. Proceeding with abandonment of traditional legacy fossil fuels before cost-effective alternatives are available will undermine U.S. energy security. As shown in Figure 4 below a movement away from U.S. oil and gas to specialty minerals will move the national economy from a position of energy independence to energy insecurity.

Figure 4

The U.S. is a Leader in Oil and Gas Production

(In specialty minerals, the U.S. is highly dependent on foreign sources of supply)



a. Are you concerned with China's poor environmental record?

According to official U.S. government sources, the People's Republic of China (PRC) is the world's largest emitter of greenhouse gases; the largest source of marine debris; the worst perpetrators of illegal, unreported, and unregulated (IUU) fishing; and the world's largest consumer of trafficked wildlife and timber products. While the Chinese people have suffered the

worst environmental impacts of its actions, Beijing also threatens the global economy and global health by unsustainably exploiting natural resources and exporting its willful disregard for the environment through its One Belt One Road initiative. Tragically, the Chinese Communist Party (CCP) represses civil society and a free press, slowing changes that would benefit its citizens and people all over the world.

Despite claims of international environmental leadership, China's energy-related carbon dioxide (CO2) emissions are rising. It has been the world's largest annual greenhouse gas (GHG) emitter since 2006. China's total energy-related emissions are twice that of the United States and nearly one third of all emissions globally. Beijing's energy-related emissions increased more than 80 percent between 2005-2019, while U.S. energy-related emissions have decreased by more than 15 percent. In 2019 alone, China's energy-related CO2 emissions increased more than 3 percent, while the United States' decreased by 2 percent. Beijing claims "developing-country" status to avoid shouldering more responsibility for reducing GHG emissions–though its per capita CO2 emissions have already reached the level of many high-income countries. China's increasing emissions counteract the progress of many other countries around the world to reduce global emissions.

China's unsafe industrial processes also make it the world's greatest emitter of mercury, a neurotoxin, and a major public health threat when allowed to pollute the air, water, and soil. China leads the world in mercury air pollution from its own dirty coal-burning power plants, as well as the plants that Chinese state-owned companies finance, build, and operate in other countries. The United States was the first country to join the 2013 Minamata Convention on Mercury, an international agreement that seeks to protect human health and the environment by comprehensively addressing mercury sources, trade, its use in products, emissions, storage, and waste. In addition, the U.S. Department of State's Mercury Program funds projects to promote better environmental practices among artisanal and small-scale gold miners (ASGM), reducing the use of mercury used while maintaining or increasing the miners' recovery of gold. The program also funds projects to reduce mercury emissions from coal combustion. PRC is also Party to the Minamata Convention on Mercury, yet it continues to enable its citizens to promote mercury use in ASGM in many developing countries.

Senator CARPER. Mr. Pugliaresi, thank you very, very much.
Last, but not least, we will listen to Ms. Koch.
We thank you for your testimony. Please proceed.

STATEMENT OF LEANN JOHNSON KOCH, PARTNER, PERKINS COIE, LLP

Ms. KOCH. Thank you, Chairman Carper, Ranking Member Capito, and members of the Committee, for the opportunity to talk about the Renewable Fuel Standard.

I have spent the entirety of my 30 year career representing the petroleum refining industry, and particularly, small refineries. I know their companies; I know their people; I know their communities, and now I also know the very real threat they face as a result of EPA's proposal to end small refinery hardship relief under the Renewable Fuel Standard.

I am referring, of course, to what Senator Capito described: EPA's December 7, 2021, proposal to issue a blanket denial of all pending small refinery hardship petitions. The EPA's deadline to issue their decisions was 90 days after the petitions were submitted. Instead, they now intend to deny them retroactively, causing small refineries to enter the market to buy RINs at their near record highs.

Most important and most telling is the fact that EPA's proposed denial did not reference its legally required consultation with the Department of Energy, and the Department of Energy's conclusion that if EPA acts as they propose to do, small refineries will be at risk of shutdown and bankruptcy. Notwithstanding that advice from the Department of Energy or legally required consultation, EPA is moving ahead with its plans. Certainly, this was material information to parties asked to provide comments on the fate of small refineries.

Senators, I am sure you are acutely aware of the fact that gas prices are at their highest levels in 8 years, and that the inflation rate is increasing faster now than in the last 40. And we are at a crossroads. If EPA persists ignoring its statutory duty and taking aim at America's small refineries, it will not only violate the law, it will exacerbate these already adverse economic conditions that our country faces. The harm to refineries and to the U.S. economy will be harm for harm's sake, because denying small refinery hardship relief cannot and will not affect 1 gallon of biodiesel. No biodiesel blending will be lost.

At Congress's direction, the Department of Energy in a 2011 report determined that small refinery hardship would grow increasingly acute as the volume mandates increase, because as the volume mandates increase, RIN prices increase. When RIN prices increase, small refineries' costs increase, and that is because small refinery hardship is caused by their limited ability to blend, not their unwillingness to blend.

EPA's 2021 proposed denial concludes that a small refinery with limited access to renewable fuel blend stocks, no downstream blending capability, no retail capability, no pipelines to access lucrative product markets, will have the exact same costs to the penny to comply with the Renewable Fuel Standard as the largest integrated oil company in the United States, companies that have

the ability to export their fuel and avoid the RFS mandate completely, companies with the ability to blend others' fuels, fuel produced by small refineries, to generate excess RINs, and the ability to take those excess RINs and trade them, speculate in them, in the wholly unregulated $30 billion RIN market. Large, integrated refineries report in their public reports earning tens of millions of dollars in profits speculating in RINs.

I listened to a hearing talking about the harm to the biofuels industry from granting small refinery hardship relief, which is a fiction. Small refineries, first of all, disproportionately produce diesel, not gasoline. They blend as much ethanol as they can, but gasoline is a small part of their production. The data demonstrate that there is zero correlation between small refinery hardship relief and the blend rate, generally. So, in the years when the hardship relief was granted more than in prior years, there was zero impact on the blend rate.

This is a question that we have to have Ms. Skor explain to us, because there is clearly no correlation between the two.

Forcing small refineries to buy RINs in record high RIN prices will result in their failure. It will result in their closure, and it will result in their bankruptcy, according to the Department of Energy, and EPA needs to step back.

[The prepared statement of Ms. Koch follows. Due to size constraints some documents are not included below but are available in Committee files.]

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Written Statement of LeAnn Johnson Koch, Partner, Perkins Coie LLP

Senate Committee on Environment and Public Works
Renewable Fuel Standard Hearing

February 16, 2022

Thank you for the opportunity to discuss the Renewable Fuel Standard. My name is LeAnn Johnson Koch and I am a Partner with the law firm Perkins Coie, LLP here in D.C. I've had the privilege, over the past thirty years of my career, to represent the petroleum refining industry and particularly small refineries. I know their companies, their people, their communities, and now I also know the very real threat they face as a result of EPA's proposal to end small refinery hardship relief under the Renewable Fuel Standard.

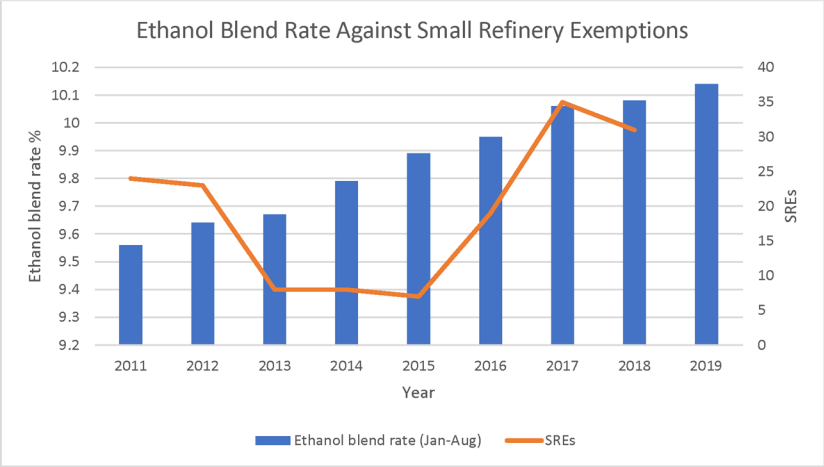
I'm referring to EPA's December 7, 2021 proposal to issue a blanket denial of all 65 pending small refinery hardship petitions, as well as the already-issued exemptions for 2018, and soliciting feedback from the biofuels industry, and other small refinery adversaries, on its plans to do so. Most important and most telling is the fact that EPA's proposed denial did not mention the results of its legally required consultation with the Department of Energy in which DOE concluded that without hardship relief small refineries would be at risk of shutdown and bankruptcy. Certainly, this was material information that should have been made available to the parties asked to provide comments on the fate of small refineries and it is material information for this Committee to consider.

Senators, I am sure you are acutely aware of the fact that gas prices are at their highest levels in the past 8 years and that the inflation rate is increasing faster now than it has in the last 40 years. We are at a crossroads. If EPA persists, ignoring its statutory duty and deliberately taking aim at America's small refineries through a mass adjudication and denial of four years of small refinery hardship petitions, it will not only violate the law, it will exacerbate the already adverse economic conditions that our country faces. The harm to small refineries and the US economy will be for harm's sake because denying small refinery hardship will not result in one more drop of blending of biofuels.

At Congress's direction, the Department of Energy, in a 2011 report, studied the risk of harm to small refineries and predicted that small refinery hardship would grow increasingly acute due to increasing renewable fuel volume mandates (the blendwall), the resulting increases in the price of compliance credits/RINs, and the inability of small refineries to position themselves to avoid the high cost of RINs. EPA's 2021 Proposed Denial concludes just the opposite—that a small refinery with limited access to renewable fuel blendstocks, no downstream blending or retail, or pipelines to access lucrative product markets will have the exact same cost (to the penny) of compliance with the RFS as the largest integrated oil company, companies with the ability to export their fuel and avoid the RFS obligation, blend others' fuel and generate excess RINs, and earn windfall profits speculating in the RIN market. EPA's theory is unsupported. It is described

by impartial academics as "implausible"[1] and demonstrated to be wrong by a second impartial academic study based on empirical data from small refineries.[2]

I listened to a January 20, 2022 hearing in which a Congresswoman was remarking about harm to the biofuels industry as a result of small refinery hardship relief. Yet, the years in which small refinery hardship relief was the greatest, (2016–2018) the biofuels blend rate increased. In fact, the data demonstrates that small refinery hardship relief has no impact on the blend rate. *See* figure below.



The reasons are straightforward and logical. Small refineries are harmed by the RFS because of their limited ability to blend biofuels, forcing them to buy RINs that are more expensive than complying through blending.[3] In addition, small refineries disproportionately produce diesel fuel and biodiesel is not available in all markets and/or is blended at lower rates than ethanol. When a small refinery receives hardship relief, it is being relieved of its obligation to buy RINs for blending that has already occurred downstream, making it impossible, as the data demonstrates, to impact biofuels blending.

You may not recognize my clients' names. Nevertheless, you may have driven here today on a gallon of gas that my client produced and, just because you do not see their name at the pump, you should not underestimate their critical role in the fuel supply. EPA's campaign is being

[1] Cody Nehiba & Gregory B. Upton Jr., Comment: U.S. Environmental Protection Agency's Proposed RFS Small Refinery Exemption Decision, Louisiana State University Center for Energy Studies at iv, vi (Feb. 7, 2022) (hereinafter "LSU Economic Report") [attached at Tab A].
[2] *See* Timothy Fitzgerald, Ph.D., Empirical Analysis (2022) (hereinafter "Fitzgerald Empirical Analysis") [attached at Tab B].
[3] *See* Timothy Fitzgerald, Ph.D., Comments on EPA Proposed RFS Small Refinery Exemption Decision (2022) (hereinafter "Fitzgerald Economic Report") [attached at Tab C].

undertaken without regard to the impact of the loss of small refinery production on the already exorbitantly high gas prices, the risk of increasing inflation, job loss—including *union* job loss—in rural communities, the loss of fuel supply in rural communities serviced by small refineries, and the resultant harm to the states in which they operate, from Pennsylvania to California. If EPA is successful, by mid-summer or the fall, the devastating effects of EPA's actions will be seen far and wide at the pump and in the states that small refineries call home.

Senators, EPA is deliberately ignoring your direction to grant small refinery hardship relief to prevent disproportionate economic hardship and after being told by the Department of Energy that it would be putting small refineries at risk of closure and bankruptcy if it failed to do so. EPA must honor Congress' direction and abandon its plan to write small refinery hardship relief out of the Clean Air Act on the ill-conceived notions that every single refinery in the US has the exact same cost of compliance and recovers 100% of its costs of RFS compliance or that granting hardship relief lowers the blend rate. If EPA doesn't, Senators, we should expect to see noncompliance, shutdown, and closure of small refineries adding to the already crippling gas prices. America stands to lose critical supply, with zero benefit to the biofuels industry.

I. Small refineries are disproportionately harmed by the RFS program.

The Department of Energy ("DOE"), in a 2011 report for Congress, performed a detailed analysis of how the RFS program would evolve over time and cause harm to small refineries.[4] As explained in the 2011 DOE Study, small refinery hardship is caused by the increasing renewable fuel volume mandates (blendwall), the resulting increase in the price of RINs, and the inability of small refineries to position themselves to avoid the harm due to their lack of vertical integration, lack of market power, and capital constraints. Therefore, small refinery harm was expected to grow worse over time, not diminish, as the volume mandates increased.

> As the RFS mandate increases, obligated parties will demand more RINs, adding upward price pressure. As the mandate increases, increasing the supply of RINs becomes difficult or nearly impossible. In anticipation of the blend wall, obligated parties may stockpile RINs through discretionary blending in anticipation of a shortage of blending opportunities. Those parties that are short, i.e. cannot generate enough RINs through their own facilities to meet their RVO, will need to purchase RINs and could suffer significant economic hardship. Declining ethanol prices would probably be favorable to refiners/blenders that predominately blend ethanol rather than purchase RINs for blending. Many small refiners do not retain control over the blending of their products, and must purchase additional RINs. *Obligated parties that rely on purchasing RINs would be adversely affected when the blend wall is reached and their RINs inventory has been depleted.*[5]

The 2011 DOE Study also explained that the size and scope of an obligated party affects the party's compliance options under the RFS:

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[4] U.S. Department of Energy, Small Refinery Exemption Study: An Investigation Into Disproportionate Economic Hardship (2011) (hereinafter "2011 DOE Study"), available at https://www.epa.gov/sites/production/files/2016-12/documents/small-refinery-exempt-study.pdf [attached at Tab D].

[5] 2011 DOE Study at 17–18 (emphasis added).

> The response to the RFS2 requirements depends in large measure on the size and scope of the operations of individual companies. Large integrated refiners can more easily obtain financing for blending facilities, generate options, accommodate their needs efficiently and shift emphasis from one sector to another as opportunities indicate. For example, over the past couple of years, compliance strategies for larger companies included engaging in joint ventures with ethanol producers, investing in companies in the renewable sector, or conducting research on renewable fuels. As a result, RFS2 compliance costs for the larger refiner may be a small part of overall operating costs.
>
> Small companies are more limited in their options. They face a number of challenges and access to capital is generally limited or not available. Even when capital is available, they may have to choose between making substantial investments in blending and investing in other needed facilities to improve operating efficiencies to remain competitive.[6]

Just as EPA predicted, large integrated refiners have positioned themselves to respond to the increasing volume mandates by entering joint ventures with biofuels producers and through their control of blending and retail. Instead of either buying renewable fuel for blending or purchasing RINs for compliance, these companies are producing renewable fuels. Large, integrated refiners are tremendously efficient, due in large part to their size, market reach and capital resources. This in turn allows them to lower their overall costs of production, so that they can capitalize further on their ability to secure RINs through the large amount of blending and retail they control. At the same time, small refineries have been more limited in their ability to enter new business areas in other geographic regions to displace established, well-funded, long time market players from the wholesale and retail markets they control. This is not easily, cheaply, or quickly accomplished and requires changing how small refineries operate. DOE understood that the refiner that blends in excess of its RVO and the unobligated gasoline marketer would have a significant cost advantage over small refineries at the rack.[7]

One aspect of the RFS program that DOE did not predict in 2011 is the magnitude of the volatility and price spikes in the RIN market. RIN prices have increased by 4000%, exempt distributor/retailer chains have retained windfall RIN revenues rather than investing in renewable fuel blending, retailers are "fuel agnostic" and unmotivated to sell higher ethanol blends,[8] the RIN market has experienced unprecedented fraud, and distributor/retailers are lining their pockets instead of passing along RIN value to encourage E15/E85 use. While DOE predicted the disproportionate economic hardship ("DEH") caused by the structural and economic differences between small refineries and other market players, it did not understand how the dysfunctional RIN market would further exacerbate the disproportionate harm.

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[6] 2011 DOE Study at 23.

[7] 2011 DOE Study at B-5.

[8] Letter from David Masuret, Senior Vice President of Petroleum Supply and Operations, and Matthew Durand, Manager of Government Affairs and Public Policy, Office of the General Counsel, Cumberland Farms, to Gina McCarthy, Administrator, U.S. Environmental Protection Agency 9 (Nov. 2, 2016), available at EPA-HQ-OAR-2016-0544-0055.

II. EPA's denial of small refinery exemptions is based on a new and incorrect interpretation of the Clean Air Act.

On December 7, 2021, EPA issued a proposal to deny all 65 pending hardship petitions and effectively remove the ability for small refineries to receive SREs moving forward ("Proposed Denial").[9] In the Proposed Denial, EPA bases its decision upon two new conclusions. Specifically, EPA concluded that: (1) a now-disavowed Tenth Circuit case requires small refineries to demonstrate that any disproportionate economic hardship is caused *only* by compliance with the RFS program; and (2) the RFS program does not cause small refineries *any* economic hardship because all small refineries always pass their compliance costs on to customers, no matter their market or situation. As explained in this testimony, EPA's Proposed Denial contravenes the Clean Air Act ("CAA"), as well as the information provided by small refineries in their hardship petitions.

A. As an initial matter, the Tenth Circuit has vacated the *RFA* decision on which EPA purports to rely for its new statutory interpretation.

EPA states that the "change in its interpretation" of the Clean Air Act is "compelled by" the Tenth Circuit's 2020 ruling in *Renewable Fuels Association, et al. v. EPA*, 948 F.3d 1206 (10th Cir. 2020) ("*RFA*").[10] That is incorrect because *RFA* has no force. The Tenth Circuit vacated the *RFA* judgment *in its entirety* and recalled the mandate, disclaiming its prior rulings on all issues.

RFA involved EPA's decision to grant SREs to three small refineries for the 2016 and 2017 compliance years. On January 24, 2020, the Tenth Circuit vacated those grants because (1) it interpreted the Clean Air Act as requiring small refineries to have consistently received SREs for all previous years of the RFS program to remain eligible for future exemptions (and the refineries had gaps in their exemption histories); (2) it interpreted the Clean Air Act to authorize EPA to extend exemptions only where RFS compliance costs were the sole cause of the small refinery's disproportionate economic hardship ("DEH"), and EPA had granted exemptions based on other economic factors; and (3) EPA did not explain whether or why the passthrough principle (i.e., that merchant refiners pass through to consumers most or all of their RIN purchase costs) was inapplicable to the refineries. *See RFA*, 948 F.3d at 1253-56. The Tenth Circuit remanded the case "for further proceedings consistent" with its opinion, *id.* at 1258, and issued the mandate on April 15, 2020, *Renewable Fuels Ass'n v. U.S. EPA*, Case No. 18-9533 (10th Cir. Apr. 15, 2020), Doc. No. 010110333954.

The U.S. Supreme Court granted certiorari in *RFA* and reversed the Tenth Circuit's decision on June 25, 2021. *HollyFrontier Cheyenne Refin. v. Renewable Fuels Ass'n*, 141 S. Ct. 2172 (2021) ("*HollyFrontier*"). The Court held that the Clean Air Act does not require a refinery to receive an exemption for all prior years to remain eligible for future exemptions from RFS compliance. *Id.* at 2183.

On remand from the Supreme Court, the Tenth Circuit vacated its prior judgment *in its entirety* and recalled the mandate. *See Renewable Fuels Ass'n v. U.S. EPA*, 854 F. App'x 983 (10th

[9] Proposal to Deny Petitions for Small Refinery Exemptions, Docket ID No. EPA–HQ–OAR–2021–0566, available at https://www.epa.gov/renewable-fuel-standard-program/proposal-deny-petitions-small-refinery-exemptions.
[10] E.g., Proposed Denial at 1, 2, 16–17.

Cir. July 29, 2021). On July 29, 2021, the Tenth Circuit issued a new judgment *affirming* EPA's grants of the SRE petitions and issued a new mandate. *See id.*; *see also* Case No. 18-9533 (10th Cir. July 29, 2021), Doc. No. 010110555246 (docket entry accompanying new judgment "[a]ffirm[ing]" EPA's SRE grants); *id.*, Doc. No. 010110555262 (new mandate). Unlike the prior vacated judgment, which remanded for "further proceedings in accordance with the [Tenth Circuit's] opinion," *id.*, Doc. No. 010110294793 (Jan. 24, 2020), the new operative judgment and mandate merely transferred jurisdiction back to the agency without instructions, *see id.*, Doc. No. 010110555262 (July 29, 2021) (mandate).

The Tenth Circuit quashed any possible ambiguity about the survival of its alternative holdings in *RFA* when it denied EPA's motion for clarification of the court's July 29, 2021 mandate. Recognizing that the Tenth Circuit had vacated its alternate holdings, EPA moved the Tenth Circuit on August 19, 2021, to clarify that "the alternative holdings in the Court's January 24, 2020 opinion not addressed by the Supreme Court remain in effect" and that the court's new "mandate returns the challenged agency actions back to EPA . . . for further proceedings in accordance with the alternate holdings," *id.*, Doc. No. 010110564301 (Aug. 19, 2021), despite the clear absence of such instructions. The Tenth Circuit swiftly denied EPA's motion just a week later. *Id.*, Doc. No. 010110567206 (Aug. 26, 2021). Thus, *RFA* does not "compel" EPA to change its interpretation of the Clean Air Act.

And even if the Tenth Circuit's interpretation of the statute were still in place, it would not be binding in other circuits. As EPA conceded, EPA's own regulations provide that decisions from the Tenth Circuit do not apply nationwide. 40 C.F.R. § 56.3(d); EPA's Motion for Voluntary Remand Without Vacatur at 11 n.7, Case No. 18-9533 (10th Cir. Aug. 25, 2021), Doc. No. 1911608. Only decisions from the Supreme Court and certain decisions of the U.S. Court of Appeals for the D.C. Circuit apply nationwide. 40 C.F.R. § 56.3(d).

EPA cannot rely on *RFA* as an excuse to reverse its interpretation of the Clean Air Act.

B. EPA's prior interpretation of the RFS was correct.

EPA's prior interpretation—that RIN costs do not pass through to customers with perfect efficiency and that other economic factors besides the cost of RFS compliance are relevant to the evaluation and determination of DEH—was consistent with the text of the Clean Air Act, the 2011 DOE Study,[11] and the Supreme Court's reasoning in *HollyFrontier*. EPA's new interpretation is not. Under EPA's proposed untethered approach, SREs would *never* be available. That is an unreasonable interpretation that would effectively repeal a portion of the statute. EPA does not have that power.

EPA's unsupported assertion that RIN costs are *always* passed on to customers by *all* refineries—no matter the market, no matter the situation—ignores both Congress's intent and the findings in the DOE study on which EPA has based its evaluation of SRE petitions for a decade.

[11] EPA attempts to rely on DOE's 2009 study [attached at Tab E], but Congress disapproved of that study and it was superseded by DOE's 2011 Study. There can be no doubt that when the Clean Air Act orders EPA to "consider the findings of *the* study" when "evaluating a petition," 42 U.S.C. § 7545(o)(9)(B)(ii) (emphasis added), EPA is required to consider the findings of the 2011 DOE Study—the only one Congressionally approved and still in force.

Congress drew a distinction between small and large refineries,[12] because it knew that small refineries were already disadvantaged in the market relative to large refineries and did not want to place an additional economic burden on them.[13] So Congress directed DOE to study those hardships.[14] DOE's 2011 Study found not only that small refineries can and do suffer hardship, but also that this hardship would grow more acute over time as renewable fuel volumes and RIN prices increase.[15] Despite those findings and the volumes and RIN prices increasing as predicted,[16] EPA proposes to thumb its nose at Congress[17] and DOE and pretend that there are no distinctions between small refineries and large, vertically integrated oil companies with massive blending and export operations.

EPA's new causation interpretation also contravenes the text of the statute and evinces a misunderstanding of the RFS program. EPA asserts that the Clean Air Act requires that DEH be caused by, and only by, RFS compliance,[18] "meaning that a small refinery may not simply experience a year of poor economic performance or struggle with disadvantageous operational or market constraints to merit an SRE."[19] But protecting struggling small refineries is precisely what Congress intended.[20] As EPA has always agreed (until now), Congress "did not constrain the scope of EPA's [DEH] determination or use language requiring that RFS compliance be the sole cause of hardship."[21] And as the D.C. Circuit has held, Congress required more than a bare consideration of compliance costs, "Congress required EPA to consult with DOE and to consider the findings of the 2011 Study *and other economic factors*."[22] It is only *after* doing all three—consulting with DOE, considering the 2011 Study, and considering other economic factors—that the statute grants EPA "substantial discretion to decide how to evaluate hardship petitions."[23] The Proposed Denial improperly eschews the 2011 DOE Study[24] and fails to address the statutorily required "other economic factors" beyond the cost of compliance.

EPA's interpretation also contravenes the statute because it fails to read "disproportionate" in context. Small refineries seeking an SRE must demonstrate "disproportionate economic harm."[25] But EPA proposes to sever "disproportionate" from that phrase, asserting that small refineries must demonstrate that their "*RFS compliance costs* are disproportionate compared to other refineries' RFS compliance costs."[26] EPA also tries to smuggle in a non-statutory severity

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[12] 42 U.S.C. § 7545(k), (o)(9).
[13] *Sinclair Wyoming Ref. Co. v. EPA*, 887 F.3d 986, 989 (10th Cir. 2017) ("Congress was aware the RFS Program might disproportionately impact small refineries because of the inherent scale advantages of large refineries and therefore created three classes of exemptions to protect these small refineries."); *see also* 2011 DOE Study at 23 ("Larger refiners have options available on a scale well beyond those available to smaller refiners.").
[14] 42 U.S.C. § 7545(o)(9)(A)(ii)(I).
[15] 2011 DOE Study at 17–18, 23.
[16] *See infra* Part I.
[17] Proposed Denial at 58 n.205.
[18] *Id.* at 23.
[19] *Id.* at 24.
[20] *See HollyFrontier*, 141 S. Ct. 2172, 2175–76, 2182 (2021) (describing Congress's goal in including the SRE program as one to "protect small refineries").
[21] *See e.g.*, EPA Br. in *RFA v. EPA*, 2019 WL 4597468, at *45; Proposed Denial at 58 n.205.
[22] *Hermes Consol., LLC v. EPA*, 787 F.3d 568, 575 (D.C. Cir. 2015) (cleaned up).
[23] *Id.*
[24] *See* 42 U.S.C. § 7545(o)(9)(B)(ii); *infra* n.8.
[25] 42 U.S.C. § 7545(o)(9)(B)(i).
[26] Proposed Denial at 16 (emphasis added).

requirement, insisting that any disproportionality must be "of sufficient magnitude to warrant the exemption."[27] That is not what the statute says. If RFS compliance—on its own or in conjunction with "other economic factors"—causes a small refinery to suffer any greater hardship relative to large refineries, it has suffered DEH and EPA must grant an exemption.[28]

EPA's reading is also unreasonable because it renders the SRE program a nullity. Taken to its logical conclusion, the Proposed Denial implies that a small refinery could be considered for an exemption only in years it experiences no economic hardship from any noncompliance factors (i.e., a "good year"). Yet EPA would undoubtedly deny the refinery an SRE during this "good year" because it is not experiencing sufficient economic hardship. And when a small refinery is having a "bad year," EPA would likewise deny the SRE because RFS compliance is not the sole cause of the refinery's hardship. This is nonsensical. EPA cannot effectively repeal SREs from the statute; no level of judicial deference permits the agency to do that.

Additionally, this exclusion of SREs directly contradicts the foundational assumption of *HollyFrontier*. There, the Supreme Court not only assumed the ongoing availability of SREs, but it also expressly rejected arguments for the exemptions' demise.[29] In response to arguments that Congress intended for the SRE provisions to eventually sunset on their own, the Court observed that "[i]f Congress really had wanted all exemptions to cease," it "surely [chose] an odd way to achieve it."[30] That goes double for drafting an exemption provision that never authorizes an exemption. EPA's new interpretation will undoubtedly fare no better before our nation's highest Court.

Finally, EPA's approach further demonstrates the agency is distorting the RFS program. As already discussed, Congress created SREs because it understood that small refineries are inherently disadvantaged in the fuel market and that "the RFS Program might disproportionately impact small refineries because of the inherent scale advantages of large refineries."[31] Said differently, Congress understood that the RFS was a new, additional burden on fuel producers and had the potential to harm small refineries in particular. So, Congress required EPA to relieve small refineries of this additional burden if compliance would cause hardship—on its own or in combination with "other economic factors"—and did so disproportionately.[32] Yet the Proposed Denial misinterprets RFS compliance not as an additional burden, but as the baseline, characterizing an exemption as "a significant windfall."[33] This turns the statute on its head. The grant of an SRE does not confer a benefit on a struggling small refinery, it relieves a burden. EPA's position is akin to a passerby claiming she has conferred a benefit on a fallen man by deciding not to kick him while he is down. Congress does not grant affirmative aid to struggling refineries through the SRE program, it merely prohibits EPA from kicking small refineries while they are down.

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[27] *Id.*
[28] 42 U.S.C. § 7545(o)(9)(B).
[29] *See HollyFrontier*, 141 S. Ct. at 2180–81.
[30] *Id.* at 2180.
[31] *Sinclair*, 887 F.3d at 989.
[32] 42 U.S.C. § 7545(o)(9)(B)(i).
[33] Proposed Denial at 19.

III. EPA has failed to follow the statutory process for issuing decisions on SREs.

A. EPA violated Congress's mandate to consult with the Secretary of Energy.

1. EPA's consultation with DOE is patently deficient.

The Clean Air Act requires EPA to consult with DOE when evaluating a small refinery hardship petition. 42 U.S.C. § 7545(o)(9)(B)(ii) ("In evaluating a petition under clause (i), the Administrator, *in consultation with the Secretary of Energy*, shall consider the findings of the study under subparagraph (A)(ii) and other economic factors."). While it is true that the Act "does not dictate any particular action that EPA must take following consultation,"[34] a patently deficient consultation contravenes the purpose of Section 211(o)(9)(B). And EPA's consultation with DOE is patently deficient here.

Since EPA began issuing SREs under Section 211(o)(9)(B), the Agency consistently consulted with DOE by considering the scores that DOE assigned to each small refinery per the scoring matrix that DOE included in in its 2011 Study. In fact, EPA would incorporate DOE's scores into the SRE decision documents and discuss whether EPA agreed with DOE's recommendation. In the Proposed Denial, EPA abruptly ends that practice. The Agency does not cite DOE's scores or recommendations, nor does EPA explain the extent of its "consultation" with DOE beyond the fact that EPA had "discussions in meetings and phone conversations" with DOE.[35] EPA's purported consultation with DOE is documented nowhere in the Proposed Denial docket, leaving small refineries with no sense of the substantive communications between DOE and EPA, or whether those communications rise to the level of "consultation." The extreme contrast between EPA's prior consultation process and its purported new methodology only emphasizes the insufficiency of the latter.

In communications with the Agency after the issuance of the Proposed Denial, we have learned that EPA did not "consider" DOE's scores in its evaluation of the 2019 petitions under the 2011 DOE Study.[36] And because EPA chose not to consider DOE's 2019 scores, DOE did not send 2020 scores to EPA until small refineries requested access to those scores. EPA's refusal to "consider" DOE's scores contravenes the Clean Air Act and belies EPA's failure to consult with DOE.

The word "consultation" is not bereft of meaning. The word ordinarily means "[t]he act of asking the advice or opinion of someone."[37] Where the Secretary of Commerce did not proffer any evidence in the administrative record showing that the National Marine Fisheries Service affirmatively solicited the advice or opinion of the Regional Councils regarding its proposed regulations, the Secretary failed to meet the requirement under the Atlantic Coastal Act to consult

[34] Proposed Denial at 21.
[35] Proposed Denial at 21.
[36] Small refineries originally requested the DOE scores associated with their 2019 and 2020 hardship petitions on December 10, 2021, after learning in the Proposed Denial that EPA has decided it no longer will consider DOE's evaluation of DEH under the 2011 DOE Study scoring matrix. EPA did not provide copies of DOE's scoring documents associated with the pending SREs until January 7 and January 19, 2022. EPA has access to these correspondences.
[37] *See Campanale & Sons, Inc. v. Evans*, 311 F.3d 109, 117 (1st Cir. 2002); Consultation, *Black's Law Dictionary* (11th ed. 2019).

with the Regional Councils, which were "presumed to have expertise that the Secretary does not."[38] Failure to consult amounts to an agency action "without observance of procedure required by law," 5 U.S.C. § 706(2)(D), warranting EPA's proposal, if finalized, to be set aside.[39]

2. EPA's newfound reliance on superseded analysis does not qualify as the required consultation with DOE.

In lieu of consultation with DOE, EPA is now trying to rehabilitate the study DOE produced in 2009 ("2009 DOE Study").[40] But because the 2011 Study superseded the 2009 Study, EPA may not rely on it.[41] EPA claims "the 2009 DOE Study accurately forecasted what was likely to occur given the highly competitive fuels market with which DOE was familiar."[42] EPA specifically cites to the conclusion in the 2009 DOE Study that "small refineries would not face DEH from compliance with the RFS program . . . *provided that the RIN market proved to be liquid and competitive*."[43] The assertion that follows—that the RIN market has "developed to be open, competitive, liquid, and functioning as intended"—is inconsistent with reality[44] and EPA knows that. The same day that EPA issued the Proposed Denial, EPA announced the proposed RFS renewable fuel blending volumes for 2020, 2021, and 2022.[45] In that proposal, the Agency acknowledged that the RIN market currently is illiquid, that there is a shortfall of available RINs, and that RINs are not in the hands of the parties that need them for compliance:

> . . . [I]t may be challenging for the market to satisfy the 2022 annual standards and the 2022 supplemental standard entirely with renewable fuel use in 2022. Given this, *the projected shortfall in RIN generation in 2019, and the uneven holding of carryover RINs among obligated parties*, we expect that further increasing the standards with the intent to draw down the carryover RIN bank would lead to significant deficit carryovers and potential noncompliance by some obligated parties that own relatively few or no carryover RINs.[46]

EPA's attempt to characterize the RIN market as liquid and competitive is also belied by the Agency's own past public statements. EPA has acknowledged that RIN prices are not merely the result of the supply and demand for RINs themselves, but "are a function of multiple factors including but not limited to changes in petroleum prices, agricultural feedstock (e.g., corn, soy) prices," as well as EPA's own manipulation of "RFS standards and expectations of future EPA

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[38] *Evans*, 311 F.3d at 116 n.7.
[39] *Id.* at 116.
[40] EPACT 2005 Section 1501 Small Refineries Exemption Study, DEPT. OF ENERGY (Jan. 2009), available at https://downloads.regulations.gov/EPA-HQ-OAR-2010-0133-0139/content.pdf.
[41] *See* 42 U.S.C. § 7545(o)(9)(B)(ii); *Hermes*, 787 F.3d at 575 (holding that "Congress required EPA to . . . consider the findings of the 2011 Study"); *infra* n.8.
[42] Proposed Denial at 21.
[43] Proposed Denial at 21 (emphasis added).
[44] *See supra* Part I.
[45] Renewable Fuel Standard (RFS) Program: RFS Annual Rules, 86 Fed. Reg. 72436 (Dec. 21, 2021) ("Proposed Volumes Rule") (EPA announced the proposal on December 7, but it was not published in the Federal Register until December 21).
[46] *Id.* at 72455 (emphasis added).

policy decisions."[47] Because EPA consistently misses statutory deadlines and erratically reevaluates volume limits, EPA's actions on their own render the market illiquid and noncompetitive. But EPA also "entered into a Memorandum of Understanding . . . with the Commodity Futures Trading Commission" to facilitate EPA's investigation into "RIN market manipulation."[48] Obligated parties warned EPA about this pervasive manipulation.[49] The 2009 DOE Study's findings are inconsistent with EPA's past statements and current realities.

Congress considered the 2009 DOE Study deficient when it was prepared, and time has made it even clearer that the 2009 analysis does not accurately reflect the realities of the RFS program, the RIN market, or small refinery hardship. Now, EPA downplays Congress' rejection of the 2009 DOE Study, stating only that "some members of Congress directed DOE to revisit the [2009 DOE Study]."[50] However, the Senate Committee on Appropriations was clear that the 2009 study was entirely insufficient and needed to be redone:

> "[T]he [2009] study contained inadequate small refinery input, did not assess the economic condition of the small refining sector, take into account regional factors or accurately project RFS compliance costs. Therefore, the Committee *does not believe the study is complete* . . . . the Department is directed to reopen and reassess the Small Refineries Exemption Study by June 30, 2010."[51]

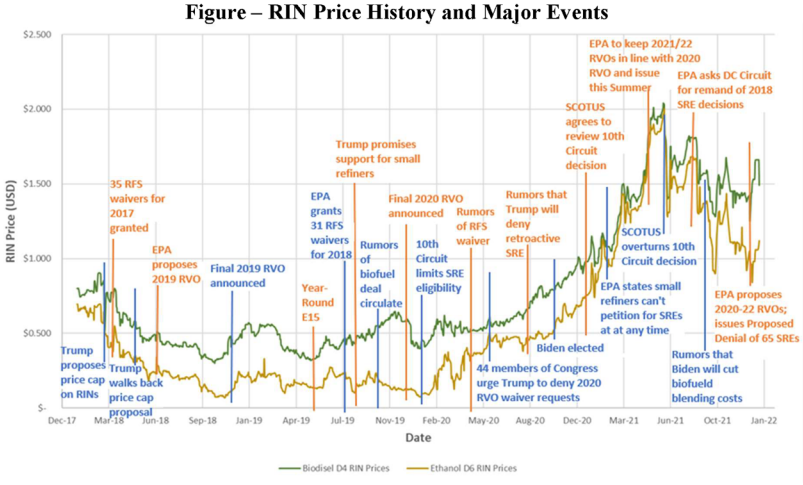
The RIN market projections relied upon in the 2009 DOE Study grossly underestimated the increase in RIN prices and the volatility of the marketplace during the life of the RFS program. In the 2009 study, DOE cited to RIN prices from May through November 2008, which were trading for less than $0.05/gallon, as evidence that the market—at that time—was "over-supplied with RINs."[52] DOE also used the U.S. Energy Information Administration's ("EIA") projected RFS compliance cost per gallon of product for the years 2009 through 2022 as a proxy for the value of RINs during those years. EIA projected that even after 2013, when the blend wall would be reached, there would be "only two years in which the RFS2 program raises produced prices more than $0.03 per gallon."[53] DOE interpreted that projection "to indicate that credits should be available and that credit prices will not be excessive."[54] In reality, RIN prices skyrocketed once the E10 blend wall was reached and, due in large part to increasing RVOs as well as market speculation, the market remains volatile. In 2021, RIN prices reached an all-time high—D6 RINs were priced nearly *4,000% higher* than the prices DOE cited in the 2009 study.[55] Since 2017 in particular, the disconnect between the flawed 2009 DOE Study and the reality of the RIN market

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[47] Modifications to Fuel Regulations To Provide Flexibility for E15; Modifications to RFS RIN Market Regulations, 84 Fed. Reg. 27013 (Jun. 10, 2019).
[48] *Id.*
[49] Comment Letter submitted by LeAnn Johnson Koch, Perkins Coie, regarding Modifications to RFS RIN Market Regulations at 3–4, 7–9, Docket ID EPA-HQ-OAR-2018-0775-0839 (Apr. 29, 2019) (discussing RIN theft and other market manipulation methods).
[50] Proposed Denial at 12.
[51] Senate Report 111-45, at 109 (2009) (emphasis added) [attached at Tab F].
[52] 2009 DOE Study at 7.
[53] 2009 DOE Study at 9.
[54] 2009 DOE Study at 9.
[55] *See* Ethanol RINs Fetch $2 for First Time Ever; More Record Highs for D6, D4, RVO, OPIS (June 10, 2021).

has been breathtaking. RIN prices have been volatile, reacting to rumor, rulemaking (or lack thereof), judicial determinations, suggesting the market is far from operating "as intended":[56]

Figure – RIN Price History and Major Events



Because the projections in the 2009 DOE Study were wildly inaccurate, there is no merit to EPA's attempts to revive the study.

In addition to the inaccurate projections, DOE also littered the 2009 study with caveats and assumptions, rendering its conclusions unreliable and not useful. At the time DOE was preparing the study, credits were readily available at a "nominal value" and "compliance volumes [had] been in excess of the RFS requirements."[57] DOE based its assumption that small refineries would not experience DEH on those conditions, which have not existed for nearly a decade. DOE rightly observed that, at the time the study was prepared, "[i]t is too early to project whether these [RIN] markets will continue to be liquid and competitive."[58] And it is true that the 2009 DOE Study failed to predict the "economic downturn [that] reduced the profitability of the refining industry, which has disproportionately impacted some small refiners," "the expiration of the biodiesel production credit [that] reduced production and [ ] caused the price of biomass-based diesel RINs to increase," and, importantly, the 2009 DOE Study did not "capture the unique factors contributing to disproportionate economic hardship" because DOE had failed to consult with individual small refineries.[59]

[56] Proposed Denial at 21.
[57] 2009 DOE Study at 2.
[58] 2009 DOE Study at 13.
[59] 2011 DOE Study at 1–2.

3. EPA has abandoned its over ten-year practice of adopting the 2011 DOE Study because it does not support the Agency's new conclusions.

The projections relied upon in the 2009 DOE Study could not be further from the realities of the RIN market. That is precisely why Congress required DOE to reassess the market and the effects of the RFS on small refineries. Once DOE performed the detailed analysis missing from the 2009 study of how the RFS program would evolve over time and cause harm to small refineries, Congress approved the 2011 DOE Study. In 2016, the Senate Committee on Appropriations directed EPA "to follow DOE's recommendations *which are to be based on the original 2011 Small Refinery Exemption Study*" and if EPA ever disagreed with DOE's recommendation, EPA was directed to "provide a report to the Committee on Appropriations and to the Secretary of Energy that explains the Agency position. Such report shall be provided 10 days prior to issuing a decision on a waiver petition."[60] The Senate's language and directive has been carried forward for several years, most recently in the Consolidated Appropriations Act for 2021.[61] In the Proposed Denial, EPA fails to explain why it is defying the Senate's directive.

4. EPA has not established a legitimate basis for abandoning the 2011 DOE Study.

EPA is proposing to resurrect the 2009 DOE Study, despite not only Congress' admonishment of that study and DOE's subsequent assessment that the findings were incorrect, but also a decade's worth of real data that contradicts the projections made in the 2009 DOE Study. Quite simply, EPA is abandoning its longstanding adoption of the 2011 DOE Study because the findings in that study do not support EPA's newfound and politically motivated interpretation of small refinery hardship relief.

For nearly a decade, EPA adopted the 2011 DOE Study and its findings, acknowledging the expertise DOE provides to the evaluation process:

> DOE's expertise in evaluating economic conditions at U.S. refineries is fundamental to the process both DOE and EPA use to identify whether DEH exists for petitioning small refineries in the context of the RFS program. After evaluating the information submitted by the petitioner, DOE provides a recommendation to EPA on whether a small refinery merits an exemption from its RFS obligations. As described in the DOE Small Refinery Study, DOE assesses the potential for DEH at a small refinery based on two sets of metrics. . . . DOE's recommendation informs EPA's decision about whether to grant or deny an SRE petition for a small refinery.[62]

[60] S. Rep. No. 114–281 at 71 (2016).
[61] *See* Pub. L. No. 116-260 (Mar. 2021), https://www.congress.gov/117/cprt/HPRT43750/CPRT-117HPRT43750.pdf.
[62] Memorandum from A. Idsal, Acting Assistant Administrator, EPA Office of Air and Radiation, to S. Dunham, Director, EPA Office of Transportation and Air Quality (Aug. 9, 2019) [attached at Tab G].

Also during that time, EPA made clear that it was consulting with DOE by considering DOE's recommendation whether a refinery merited exemption from the RFS, which was based on DOE's evaluation of a refinery on the basis of the two sets of metrics.[63]

For as long as DOE has been applying the scoring matrix, and EPA has been evaluating petitions for small refinery hardship relief, DOE has made clear that there was insufficient information to score metric 2.d, which measures whether a small refinery's RVO is a net cost or a net revenue. While this metric was not scored in the 2011 Study because of an alleged "lack of consistency" among the responders to the DOE small refiner survey, DOE expressly noted that "depending upon the business model of the small refiner, complying with their RVO can either be a net cost if they purchase all of their RINs or can generate revenue should they be able to actively trade RINs in the open marketplace."[64]

Now, EPA claims DOE never "assess[ed] in [the 2011 DOE Study] whether their assumptions that refiners bear different costs for RINs and that they may not be able to pass these costs onto consumers in the marketplace actually occurred."[65] That is not true. DOE understood that parties would experience RFS costs differently—that is why DOE included metric 2.d ("RINs net revenue or cost") in the scoring matrix. It particularly understood that RIN prices would become untethered from the price of blending after the E10 blend wall[66] was reached—a concept that has grounded our understanding of the RFS for nearly 10 years but is not mentioned once in the Proposed Denial. As stated above, DOE predicted that as the RFS mandate increases, RIN-short parties "will need to purchase RINs and could suffer significant economic hardship."[67]

B. EPA's transformation of the individual hardship petition process contravenes the Clean Air Act.

The Clean Air Act mandates that EPA's decision on an individual SRE petition be based on (1) the refinery-specific information provided in SRE petitions and (2) consultation with DOE.[68] What the statute does *not* contemplate is inviting adversaries of small refineries, such as biofuels groups, to participate and attack SREs without *any* information about small refineries.

Until now, EPA consistently has issued decisions on SRE petitions through the informal adjudication process, and there is good reason for that. SRE petitions provide information to the federal government that demonstrates the disproportionate economic hardship caused by RFS compliance. That information is extremely sensitive and candid in its description of the refineries' hardship due to RFS compliance. It illustrates the vulnerability experienced by small refineries, both financially and commercially. Small refineries have gone to great lengths to maintain and defend the confidentiality of the financial and business information they provide in their hardship petitions. That is because, if released, the information could allow competitors, customers, and

[63] *See* Excerpt from redacted 2017 decision document [attached at Tab H].
[64] 2011 DOE Study at 35.
[65] Proposed Denial at 22.
[66] "A blend wall is the aggregate limit to which a renewable fuel can be blended into its recipient motor fuel. The blend wall reflects both physical limitations and regulatory restrictions on the ability of the vehicle/fuel system to absorb renewable fuels. As a result, a blend wall is specific to a particular renewable fuel and specific to a particular motor fuel." 2011 DOE Study at 13.
[67] *Id.* at 17–18.
[68] 42 U.S.C. § 7545(o)(9)(B)(ii).

suppliers to seize upon the identified vulnerabilities to inflict reputational harm and gain a competitive advantage through any number of methods. And yet, EPA is not only allowing but *encouraging* input from biofuels groups and others vehemently opposed to any form of relief for small refineries, even though these outside parties have no understanding of the confidential business information provided by small refineries.

In fact, EPA is the only party with access to all the information informing its conclusions on the SRE petitions. EPA has not disclosed any of its underlying data to the public, let alone the small refinery petitioners. EPA's assertion that "all obligated parties recover the cost of acquiring RINs by selling the gasoline and diesel fuel they produce at the market price, which reflects these RIN costs (RIN cost passthrough)" is based on scant data that EPA has interpreted incorrectly.[69] In total, EPA cites to only one academic study[70] and the working paper version of the published article.[71] Otherwise, EPA relies heavily on an internal memorandum from 2015.[72] EPA does not address additional studies that directly contradict its assertion of full RIN cost passthrough, and even the single study that the Agency does cite does not support EPA's position.

Also missing from the Proposed Denial is any form of in-depth analysis of the voluminous small refinery information provided to EPA over the past three years. EPA only selectively discusses small refinery information and, in doing so, gravely mischaracterizes that information. As discussed above, the small refinery information, without question, is CBI and should not be discussed by EPA in a public adjudication or rulemaking involving small refineries' direct competitors. The confidentiality of this information underscores the absurdity of (1) EPA's attempt to characterize its public and industry-wide analysis as an adequate evaluation of individual small refinery petitions and (2) EPA's request for public comment on the fate of confidential small refinery petitions.

In the Proposed Denial, EPA employs an administrative "process" that includes the hallmarks of both rulemaking[73] and adjudication (though not the individualized, informal adjudication required by the statute).[74] Like a rulemaking, the Proposed Denial attempts to provide "the whole or part of [EPA's] statement . . . designed to . . . interpret, or prescribe law or policy."[75] EPA is explicit: the Proposed Denial "articulat[es] EPA's current interpretation of its statutory authority."[76] EPA's chosen notice and comment procedure is its "process for formulating" that rule.[77] The Proposed Denial also acts like an adjudication by attempting to resolve pending

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[69] Proposed Denial at 26.
[70] Knittel, C.R., Meiselman, B.S., and Stock, J.H. 2017. The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard. Journal of the Association of Environmental and Resource Economists 4(4), 1081–1119.
[71] The working paper examining subsequent data: Knittel, C.R., Meiselman, B.S. and Stock, J.H., 2016. The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard: Analysis of Post-March 2015 Data. Working Paper.
[72] Burkholder, D., 2015. A preliminary assessment of RIN market dynamics, RIN prices, and their effects. Office of Transportation and Air Quality, US EPA.
[73] The Proposed Denial eschews the label "rulemaking," asserting that it "is not subject to the various statutory or other provisions applicable to a rulemaking." Proposed Denial at 7.
[74] *See* 42 U.S.C. § 7545(o)(9)(B)(ii).
[75] 5 U.S.C. § 551(4) (defining a "rule" under the APA).
[76] Proposed Denial at 7.
[77] 5 U.S.C. § 551(5) (defining a "rule making" under the APA).

petitions by applying EPA's rule retroactively—something that cannot be done through rulemaking.[78] But as an adjudication, the Proposed Denial is unlawful because it is not an individual, informal adjudication that addresses the refinery-specific facts raised in each SRE petition. (At a recent hearing, EPA called the Proposed Denial a "mass decision."[79]) Instead, EPA's request for public comment on the Proposed Denial appears to be a means to amass political support for the wholesale denial of 65 pending SRE petitions and the dramatic change in the Agency's evaluation of SRE petitions that effectively renders meaningless the SRE provision in the Clean Air Act.

C. EPA's decision to upend the SRE program appears to be influenced by inappropriate political concerns.

Media reports indicate that in November 2021, Agriculture Secretary Tom Vilsack assured that EPA has "committed" that the forthcoming renewable fuel blending quotas "won't be undercut by waivers."[80] The Secretary's statement suggests that he knew EPA's decision on the pending SRE petitions before EPA issued the Proposed Denial. As a matter of law, any influence from the United State Department of Agriculture ("USDA") is improper. The Clean Air Act does not give USDA any authority or role over SRE decisions. *See* 42 U.S.C. §7545(o)(9)(B)(ii) (the CAA authorizes only "the Administrator [of EPA], in consultation with the Secretary of Energy," to act on petitions from small refineries). Thus, there is no valid rationale for USDA's participation in or influence over the decision-making process.

While Secretary Vilsack's statement is alone cause for serious concern about the integrity of the SRE decision-making process, his statement is not the only example of USDA's apparent involvement in, and potential influence over, SRE decisions. Media reports indicated that USDA also tried to influence EPA to reduce the number of small refinery hardship exemptions for the 2018 compliance year. Prior to the issuance of EPA's decisions, former Secretary of Agriculture Sonny Perdue was tasked with reconsidering the Administration's approach to granting hardship relief to small refineries.[81] And roughly one week after the 2018 hardship decisions were released, former President Trump held a meeting to discuss those decisions with not only former Administrator Wheeler, but also officials from USDA, including the Secretary and former Deputy Secretary of Agriculture Stephen Censky,[82] as well as Terry Branstad, the Ambassador to China at that time and former Governor of Iowa, the largest corn producer in the United States.[83] The

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[78] *E.g.*, *Bowen v. Georgetown Univ. Hosp.*, 488 U.S. 204, 208–09 (1988); *Treasure State Res. Indus. Ass'n v. EPA*, 805 F.3d 300, 305 n.1 (D.C. Cir. 2015) ("[T]he APA prohibits retroactive rulemaking." (citing 5 U.S.C. § 551(4), defining a "rule" as "an agency statement of general or particular applicability and *future effect*")).

[79] Tr. at 8, Status Conference, *Cross Oil Refin. & Mktg., Inc. v. Regan*, Case No. 21cv1825 (D.D.C. Jan. 20, 2022) [attached at Tab I].

[80] Jennifer A. Dlouhy, Biofuel Quotas Won't Be Undercut by Refinery Waivers: Vilsack, BLOOMBERG LAW (Nov. 4, 2021).

[81] *See* Rob Hotakainen and Marc Heller, Trump under growing pressure to block refinery waivers, E&E GREENWIRE, June 21, 2019; *see also* Chris Clayton, Backlash Over Perdue Influence: Senators Want President to Keep Ag Secretary Out of EPA Small-Refinery Decisions, PROGRESSIVE FARMER, July 1, 2019; Refiners: Restrict USDA Access to Small-Refinery Waivers Information, PROGRESSIVE FARMER, Jul. 9, 2019.

[82] Before becoming the former Deputy Secretary, Stephen Censky served as chief executive officer of the American Soybean Association for 21 years, an organization openly opposed to small refinery exemptions.

[83] See Jennifer Jacobs, Jennifer A Dlouhy, and Mario Parker, Trump Seeks to Allay Farm-State Uproar in Oval Office Meeting, BLOOMBERG, Aug. 20, 2019; *see also* Marc Heller, Leaked memo: Trump admin mulls effort to boost ethanol, E&E NEWS, Aug. 23, 2019.

mere fact of communications between EPA and USDA regarding SREs is evidence of improper influence. These communications threaten the integrity of the SREs decision-making process, which EPA already is attempting to write out of the Clean Air Act in its Proposed Denial.

Congress has been alerted to USDA's apparent attempts to influence EPA to reduce the number of SREs the Agency granted in the past to garner further political support from the biofuels industry. The Government Accountability Office ("GAO") is now investigating the extent of inappropriate outside influence on the SRE decision-making process.[84]

IV. EPA's decision to deny the SREs is arbitrary and capricious on the merits.

A. Independent economic analyses refute EPA's conclusions that RFS compliance costs are the same for all obligated parties and that *all* obligated parties pass through their compliance costs to customers.

Timothy Fitzgerald, Ph.D.[85] reviewed and commented on the economic analysis presented by EPA in the Proposed Denial.[86] Dr. Fitzgerald concludes that EPA's "RIN cost passthrough" position "is not consistent with the empirical results relevant to this issue in the academic literature."[87] EPA's assertion that "all transactions fully recover RIN costs . . . is relying too heavily on a very small number of results and making an interpretation that is unduly strong given the entire available empirical record. EPA has chosen its interpretation, but in so doing ignores completely evidence that helps paint a more complete picture of how RFS compliance is achieved by different obligated parties."[88] The fact that EPA is "[i]gnoring the substantial evidence from other academic papers that pass-through is imperfect further undermines the . . . interpretation that EPA has elected to make based on results from a single external study."[89]

To test EPA's hypothesis regarding "the extent of pass-through of RIN costs," Dr. Fitzgerald performed an empirical analysis using "[d]aily bulk sales data from a collection of small refiners."[90] As a starting point, Dr. Fitzgerald utilized the same methodology that "seems to be the preferred methodology of EPA" in the Proposed Denial.[91] However, Dr. Fitzgerald used far more recent and relevant data, which "provides an opportunity to test [EPA's] assumption in a large number of applications to determine if it is justified."[92] Dr. Fitzgerald draws several conclusions from this empirical analysis, which refute the outdated, flawed, and overly simplistic "analysis" on which EPA based the Proposed Denial.

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[84] On January 30, 2020, as part of GAO's ongoing investigation of SRE decision-making under the RFS, Senator Barrasso and nine other senators requested that GAO expand the investigation to address additional aspects of the small refinery hardship relief, including the extent to which inappropriate political interference is affecting the implementation of the program [attached at Tab J].
[85] Timothy Fitzgerald, Ph.D. is an Associate Professor at the Rawls College of Business at Texas Tech University.
[86] *See* Fitzgerald Economic Report, [Tab C].
[87] Fitzgerald Economic Report at 1.
[88] *Id.*
[89] *Id.* at 5.
[90] Fitzgerald Empirical Analysis at 1, [Tab B].
[91] *Id.*
[92] *Id.*

Separately, the Louisiana State University Center for Energy Studies ("LSU") analyzed EPA's claims in the Proposed Denial that: (1) RFS compliance costs are the same for all obligated parties, and thus no party bears RFS compliance costs that are disproportionate relative to others' costs; and (2) all obligated parties—including small refineries—recover their compliance costs through the market price they receive when they sell their fuel products and, thus, do not experience any hardship from RFS compliance.[93] LSU's analysis utilizes economic theory, prior empirical research, and public data.

LSU concludes that "EPA's claim that RFS compliance costs are the same for all obligated parties is implausible."[94] In terms of economic theory, "[t]he fundamental economic rationale for implementing a tradable permit program [like the RFS] in lieu of a simple requirement for each individual firm is *because the costs of compliance differ across firms*."[95] The purpose of a tradable permit program "is to achieve the lowest possible compliance cost market-wide," but "this does not imply that the *average* compliance costs per unit of output is the same for all individual firms."[96] While each refinery may have the option to purchase RINs from the market at the same price, each refinery will have different compliance costs and be impacted differently.[97] EPA's claim is thus contrary to economic theory and belied by EPA's creation of the RIN market in the first place.

LSU also concludes that EPA's claim that all obligated parties, including small refineries, fully recover their compliance costs is not supported. "[T]he evidence does not suggest full pass-through of all RINs to all fuels in all locations. Thus, it is unlikely that market participants *in all situations* are able to recover their firm-specific compliance costs through the market price they receive when they sell fuel."[98] In other words, EPA's assertion that "the [RFS] program cannot impose hardship on an individual firm[] is implausible in our opinion . . ."[99]

B. EPA concedes that there are circumstances under which obligated parties cannot pass through their RIN costs.

1. EPA's theory that all RINs are passed through rests on an assumption divorced from the realities of the transportation fuels market.

EPA acknowledges in the Proposed Denial that the passthrough theory can occur only under certain conditions, and RIN costs are *not* passed through when small refineries do not purchase RINs ratably.[100] However, EPA's framing of the issue suggests that all obligated parties can buy RINs on a "ratable basis" to exactly match the volume of their fuel sales.[101] EPA states as follows:

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[93] *See* LSU Economic Report, [Tab A].
[94] *Id.* at 30.
[95] *Id.* at 17 (emphasis in original).
[96] *Id.* at iv.
[97] *Id.* at 17–21.
[98] *Id.* at 35 (emphasis in original).
[99] *Id.* at vi.
[100] *See* Proposed Denial at 48–49.
[101] EPA defines "ratable basis" as "purchase on a systematic, regular basis the number of RINs needed to satisfy their obligation for all the fuel sold each day." Proposed Denial at 48.

> Obligated parties that *choose* to purchase the RINs they need for compliance on a ratable basis . . . will recover the cost of the RINs they purchase in the sales price of the petroleum fuel they sell. Conversely, obligated parties that *choose* to delay RIN purchases, or to purchase excess RINs in advance of producing or importing petroleum fuel, may recover more or less than the price they paid for RINs in the sales price of the petroleum fuel they sell, depending on whether the RIN price on the purchase date is higher or lower than the RIN price on the date the petroleum fuel is sold.[102]

Contrary to EPA's assertion, small refineries cannot simply *choose* to buy RINs ratably. In other words, EPA's RIN passthrough theory relies on laboratory conditions that in no way resemble the real-world conditions small refineries experience when deciding how to comply. For many small refineries, purchasing RINs ratably is not possible or reasonable for several reasons (volatile and restricted cash flow, lack of access to credit, etc.). Even when small refineries can purchase RINs on a regular basis, they cannot adjust the prices of their fuel in real time to ensure that they recoup their RIN costs.

Even if small refineries could buy RINs ratably, they had reason not to do so. Because many small refineries received SREs in the past, they reasonably relied on that fact when deciding whether to acquire RINs to show compliance for the years for which they again applied for hardship relief. Small refineries had no reason to think EPA would upend the SRE evaluation process and deny all SREs moving forward, and that it would do so years after it was supposed to issue SRE decisions in the first place. Again, EPA fails to take accountability for the ways in which its failures to properly implement the RFS program have negatively affected small refineries.

To present a simplified picture of how small refineries can achieve compliance and recover their costs, the Proposed Denial contains zero discussion of how RIN trading actually works. Instead, EPA claims that "individual business decisions made by an obligated party not to ratably accrue RINs as the obligation accrues, but instead to either purchase RINs in advance or delay RIN purchases until a later date, are speculation in the RIN market, a business activity not required to comply with the RFS program."[103] To characterize small refinery behavior as "speculation"[104] is disingenuous. EPA's statement reflects a naïve understanding of business behavior. Speculation is defined as "investment in stocks, property, or other ventures in the hope of gain but with the risk of loss."[105] Small refineries are not entering the RIN market in an attempt to make profit. They are RIN-short obligated parties *required* to show compliance with the RFS program and, because they are dependent on the RIN market to do so, they have no choice but to purchase RINs in the marketplace. If small refineries could avoid the RIN market altogether, they certainly would. Put simply, small refineries are making decisions about regulatory compliance, not speculating.

In contrast to small refineries, other parties do speculate in the RIN market, because EPA allows them to do so. The Clean Air Act directed EPA to create a credit trading program in which the credits, or RINs, could be generated by parties that "over complied" and sold only to parties

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[102] Proposed Denial at 48–49 (emphasis added).
[103] Proposed Denial at 49.
[104] Proposed Denial at 50.
[105] *Speculation*, LEXICO (2022), https://www.lexico.com/en/definition/speculation.

that needed them for compliance.[106] Instead, EPA created a program in which any person may participate, generating credits for blending at any level they choose and selling RINs to anyone for any purpose. As a result, the RIN market has been captured and is controlled by large integrated refineries that generate excess RINs, large retailers (who control their own blending but are not obligated parties), and traders, all of whom are seeking to make a profit in the market.

EPA's theory that there is full RIN cost passthrough rests on the assumption that all obligated parties can buy RINs to exactly match their fuel sales in real time. Because that assumption is incorrect, EPA's theory necessarily falls apart. By characterizing the costs incurred by small refineries as a mere consequence of not buying RINs ratably, EPA concedes its passthrough phenomenon fails in real-world conditions. Its only remaining argument is a bad one made in an attempt to effectively rewrite SREs out of the statute—that RIN costs are not *caused* by the RFS and therefore cannot be "considered" by the Agency.[107]

C. EPA ignores the structural characteristics of small refineries that Congress and DOE understood made them susceptible to hardship.

EPA summarily concludes no small refineries are experiencing hardship. This contradicts the U.S. Court of Appeals for the Fourth Circuit's admonition that EPA must consider the ability of the individual small refinery to pass through its RIN costs and may not rely on an industry-wide conclusion. When assessing the RFS compliance costs for an individual small refinery, EPA must do more than cite to conclusions about "the refining industry *as a whole*."[108] The Fourth Circuit determined that it was arbitrary and capricious for EPA to rely on "an industry-wide study and a nonspecific nationwide trend" while "ignor[ing] specific evidence suggesting that [RIN] prices had a negative effect" on an individual small refinery.[109] To ignore a small refinery's "specific evidence" would render meaningless the analysis of a small refinery's DEH and would, therefore, be arbitrary and capricious.[110]

To supports its position that RIN costs are fully passed through by all parties, EPA claims that if passthrough were not occurring, "we would expect to see refiners avoiding RFS obligations"[111] by shifting production to non-obligated fuel (e.g., jet fuel or exports). This statement completely ignores the physical and financial impediments that prevent small refineries from pivoting business portfolios.[112] Moreover, many small refineries have made adjustments, including increasing blending capabilities, yet still experience hardship. Small refineries are submitting individual confidential comments showing why the Proposed Denial is inaccurate as applied to their refineries. It is critical that EPA evaluate these comments and assess each small refinery on an individual basis.

Ultimately, EPA's position that effectively writes SREs out of the Clean Air Act contradicts congressional intent. The RFS is not an "adapt or die" program. Rather, Congress

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[106] 42 U.S.C. § 7545(o)(5)(A)(i).
[107] *See supra* Part II.B. regarding the proper interpretation of the Clean Air Act's DEH causation requirement.
[108] *Ergon-W. Va., Inc. v. EPA*, 896 F.3d 600, 613 (4th Cir. 2018) (emphasis added).
[109] *Id.*
[110] *Ergon-W. Va.*, 896 F.3d at 613.
[111] Proposed Denial at 26.
[112] *Supra* Part I.

established the possibility of hardship relief "at any time" to help small refineries remain competitive and profitable.[113] The United States Supreme Court recently upheld this logic, finding that if Congress intended the small refinery hardship relief provision to be a sunset provision, under which small refineries' ability to seek relief due to DEH had a time limit, then Congress chose "an odd way to achieve it."[114]

V. EPA's new interpretation cannot apply retroactively to the pending petitions or the 2018 SREs.

EPA aims to apply the Proposed Denial to not only the pending hardship petitions, but also the 2018 remanded decisions issued two and a half years ago. On December 8, 2021, the day after EPA issued the Proposed Denial, the U.S. Court of Appeals for the D.C. Circuit remanded the 2018 SREs to the Agency.[115] On January 3, 2022, nearly a month after the remand order and nearly halfway through the comment period for the Proposed Denial, EPA notified small refineries *for the first time* that the Agency was considering including the 2018 SREs under the Proposed Denial, which could result in the reversal of more than 30 previously granted exemptions. Thus, EPA intends to apply the Proposed Denial to all pending petitions and previously granted petitions from compliance year 2018.[116] The pending petitions include at least 63 petitions that, by statute, EPA should have decided before EPA issued the Proposed Denial.[117] And, of course, EPA *already granted* the 2018 SREs. EPA cannot retroactively apply the Proposed Denial to any of the pending hardship petitions or the 2018 SREs.

A. Pending petitions

Even assuming that EPA's new interpretation is permissible (it is not, *see supra* Part II), and regardless of whether the Proposed Denial is a rulemaking, an adjudication, or both,[118] retroactive application is impermissible here. "[A]dministrative rules will not be construed to have retroactive effect unless their language requires this result."[119] And even when a rule itself purports to be retroactive and there are other "substantial justification[s] for" that application, courts will "be reluctant to find such authority absent an express statutory grant."[120] Although EPA intends to apply its new rule retroactively,[121] the Clean Air Act does not provide the necessary "express statutory grant." But even if it did, "the APA prohibits retroactive rulemaking."[122] EPA cannot retroactively apply its new rule to any of the pending hardship petitions.

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[113] 42 U.S.C. § 7545(o)(9)(B)(i).
[114] *HollyFrontier*, 141 S. Ct. 2172, 2180 (2021); *see also supra* Part II.B regarding the Supreme Court's rejection of an argument that Congress intended for the SRE provisions to eventually sunset on their own.
[115] Order, *Sinclair Wyo. Refin. Co. v. EPA*, No. 19-1196 (D.C. Cir. Dec. 8, 2021), Doc. No. 1925942.
[116] Proposed Denial at 6.
[117] 42 U.S.C. § 7545(o)(9)(B)(iii); 40 C.F.R. § 80.1441(e)(2)(ii).
[118] *See supra* Part III.B.
[119] *Georgetown Univ. Hosp.*, 488 U.S. at 208.
[120] *Id.* at 208–09
[121] Proposed Denial at 6–7 (explaining that EPA intends to apply EPA's new interpretation to "deny all the pending petitions" for hardship relief).
[122] *Treasure State*, 805 F.3d at 305 n.1 (citing 5 U.S.C. § 551(4), defining a "rule" as "an agency statement of general or particular applicability and *future effect*")).

Retroactive application of any adjudicatory aspect of the Proposed Denial is equally unlawful. EPA did not provide fair notice of this new interpretation, which eliminates SREs, in violation of small refineries' due process rights.[123] "Notice is fair if it allows regulated parties to identify, with *ascertainable certainty*, the standards with which the agency expects [them] to conform."[124] Retroactive application of a new legal rule is unlawful if a party has conformed its conduct to a prior legal regime.[125] In addition, courts disfavor retroactivity when the agency is merely effectuating a change in policy, not correcting a legal error.[126]

Here, small refineries did not receive constitutionally adequate notice that SREs would not exist, and retroactive application of the new interpretation would be unlawful and inappropriate for many reasons. *First*, under the statute, EPA should have decided the small refinery petitions at issue long ago (90 days after receipt), and small refineries were entitled to exemptions at that time.[127] EPA repeatedly missed deadlines and delayed decision[128] on pending petitions to now retroactively apply a new statutory interpretation to petitions that should have been decided under the old, correct interpretation. If EPA had timely issued decisions, small refineries that were denied hardship relief would have been able to buy RINs at significantly lower cost than the current RIN prices. *Second*, small refineries conformed their conduct to the prior legal regime when they used in their petitions the criteria in the 2011 DOE Study, including the PI-588 survey, not the defunct 2009 study or the Proposed Denial, to make the case for hardship relief. Small refineries also relied on the existence of exemptions based on DEH to their detriment. Those refineries that always or often received hardship relief reasonably believed that they would again receive hardship relief from EPA in compliance years 2019 and 2020 and did not make the significant capital or other investments (that might have put them out of business) necessary to comply.[129] *Third*, EPA switched interpretations merely to effectuate a change in policy, not to correct a legal error. As discussed *supra* Part II.A, EPA cannot claim "correction" based on *RFA* because the Tenth Circuit vacated *RFA* in its entirety and, even if *RFA* were still good law, it would not dictate how EPA should address petitions filed outside of that circuit.

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[123] "A fundamental principle in our legal system," enshrined in the Fifth Amendment's Due Process Clause, "is that laws which regulate persons or entities must give fair notice of conduct that is forbidden or required." *FCC v. Fox Television Stations, Inc.*, 567 U.S. 239, 253-58 (2012); *see also Christopher v. SmithKline Beecham Corp.*, 567 U.S. 142, 156 (2012). That principle is "thoroughly incorporated into administrative law." *Gen. Elec. Co. v. U.S. EPA*, 53 F.3d 1324, 1329 (D.C. Cir. 1995), *as corrected* (June 19, 1995) (cleaned up); *see also SNR Wireless LicenseCo, LLC v. FCC*, 868 F.3d 1021, 1043 (D.C. Cir. 2017).

[124] *Id.* (emphasis added) (cleaned up).

[125] *See Air Transport Assn. v CAB*, 732 F.2d 219, 227-28 (D.C. Cir. 1984); *Patel v INS*, 638 F.2d 1199, 1203-04 (9th Cir. 1980); *see also Natural Gas Pipeline Co. v FERC*, 590 F.2d 664, 668 (7th Cir. 1979); *Drug Package, Inc. v NLRB*, 570 F.2d 1340, 1346-47 (8th Cir. 1978).

[126] *See Verizon Tel. Companies v. FCC*, 269 F.3d 1098, 1111 (D.C. Cir. 2001); *Gun South, Inc. v. Brady*, 877 F.2d 858, 859, 862 (11th Cir. 1989). "[T]he more an agency acts like a legislator—announcing new rules of general applicability—the closer it comes to the norm of legislation and the stronger the case becomes for limiting application of the agency's decision to future conduct." *De Niz Robles v. Lynch*, 803 F.3d 1165, 1172 (10th Cir. 2015) (Gorsuch, J.).

[127] 42 U.S.C. § 7545(o)(9)(B)(iii).

[128] EPA likely knew that it was going to reverse its interpretation when it held an open-forum meeting for small refineries in August 2021. Instead, EPA delayed three more months to announce its reversal.

[129] Indeed, DOE's scores for compliance year 2019 indicate that almost all refineries would have received hardship relief if EPA had decided the petitions by the statutory deadline.

B. 2018 remanded SREs

Applying this new interpretation to the 2018 SREs raises additional issues. Reconsidering *already granted* petitions is especially inappropriate and inequitable due in part to small refineries' detrimental reliance on 2018 exemptions granted two and a half years ago.[130] And even if EPA were to reconsider and deny the 2018 SREs, EPA cannot enforce compliance. At most, it could issue only "paper denials." That is because it would be impossible for previously exempt small refineries to now comply for 2018 when the 2017- and 2018-vintage RINs necessary to demonstrate compliance are no longer available.

[130] *See, e.g.*, *Citizens Against Pellissippi Parkway Extension, Inc. v. Mineta*, 375 F.3d 412, 418 (6th Cir. 2004) ("detrimental reliance on the previous [agency determination] would militate against allowing the agency to withdraw" it); *see also Rosebud Sioux Tribe v. Gover*, 104 F. Supp. 2d 1194, 1201 (D.S.D. 2000) (declining to accord the BIA the inherent authority to reconsider its approval of a lease of tribal land, in part because the developers had "already spent more than $5,000,000 in reliance on [the Bureau's] action[s]"), *rev'd on other grounds sub nom. Rosebud Sioux Tribe v. McDivitt*, 286 F.3d 1081 (8th Cir. 2002); *Prieto v. United States*, 655 F. Supp. 1187, 1188 (D.D.C. 1987).

Overview

Daily bulk sales data from a collection of small refiners were analyzed to assess the extent of pass-through of RIN costs. This methodology follows directly from Knittel et al. (2017), is similar to that adopted by other more recent analyses such as Lade and Bushnell (2019). It also seems to be the preferred methodology of EPA in the proposed final decision rule (though it's a bit hard to tell from the description).

Data

Sales data were reported from 19 sales locations for 76 products over the calendar years 2019–2021. These data differ from other publicly-available analyses in three ways. First, they are drawn from a more recent time period than previous analyses, allowing for more timely inference about market conditions. Second, these data are detailed in terms of daily (and in some cases lot by lot) sales of specific refined products with specific counterparties at specific locations, which reflects the commercial conditions faced by obligated parties and contrasts with other studies that compare price spreads between index and average prices. By the same token, these detailed data allow inference in market segments rather than relying on pooled results. Third, the data are drawn exclusively from a group of small refiners as sellers; this group has asserted disproportionate economic harm from RFS and is directly affected by the proposed rule.

The 19 locations are located across 10 states and 4 PADDs (PADD 2 has no observations). The 76 products are quite specific, such as B2 #2 dyed ULSD (15ppm) or 87 octane E10 gasoline with branded additive. This broad array reflects the strength of the assumption that RIN prices pass through completely and immediately in all product markets. It also provides an opportunity to test the assumption in a large number of applications to determine if it is justified.

To facilitate analysis, these specific products are aggregated into fuel type categories, with pricing for the category reflecting a volume-weighted average of reported transaction prices. For example, 11,031 daily transactions across 10 distinct fuel types are aggregated into the E0 category and 26,346 daily transactions across seven fuel types are aggregated into the E10 category. The estimates compare pairs of fuels priced at the same location and yield parameter estimates that reflect the average tendency across all pairs in all locations. It is worth considering that the aggregation means that the E10 price can reflect an average across two grades of E10, such as 87 and 93 octane or branded and unbranded 87 octane, at a given location on a given day. To the extent different grades of E10 are sold at the same location on different days, the series treats the different grades as substitutes.

An important issue in these data is the treatment of weekend fuel sales. Knittel et al. (2017) drop weekends, and RIN price quotes are not available for weekends and major holidays. Refining and fuel supply is a 24/7/265 industry, which is borne out in the

data, with about 28 percent of all transactions logged on Saturday or Sunday. This has serious implications for the assumption of ratable compliance asserted strongly by EPA. To investigate further, a linear interpolation of missing RIN prices was created (the difference between Friday and Monday quotes is split between Saturday and Sunday for a regular weekend). This permits comparison with the transactions on reported days and all observed sales using the interpolated values. Not that this method does not introduce additional variance into the regressors, but it does increase the variance of the prices to be explained.

Empirical Strategy

EPA stylizes the refined product market in the proposed final decision rule in their equations (1) and (2). These equations are rearranged slightly to afford empirical estimation of the extent to which product prices reflect complete and immediate pass-through of RIN costs in all cases as asserted by EPA.

The analysis focuses on three bulk price spreads that identify how the difference in prices between obligated and unobligated fuels are related to movements in RIN prices. These three price spreads are E0 - E10, B0 - B2, and B0 - JET/KERO. The obligations in each case are slightly different. The B0-B2 spread is a very tight differential that has not previously been used as the basis for estimation. These particular data permitted testing it as an application of pass-through.

For each blend represented as ϕ (e.g., $\phi = 0.10$ for E10), the net RIN obligation can be represented as

$$R_t^{ij} = \mathbf{RVO}\ \mathbf{P}(1-\phi) - \phi RIN_t \tag{1}$$

This allows for an estimable equation to explain the difference in prices between fuels i and j as a function of R_t^{ij} at the time (t) and location (ℓ) of sale

$$\Delta p_{\ell t}^{ij} = \alpha_{\ell ij} + \beta_{ij} R_t^{ij} + \varepsilon_{\ell t}^{ij} \tag{2}$$

where ε is an error term. This is identical to equation (2) in Knittel et al. (2017).

Results

The first set of results estimate equation 2 for each of three fuel spreads in 2019–2021 using OLS with Newey-West standard errors to account for autocorrelation. This is the methodology used by Knittel et al. (2017) for an earlier period and endorsed by EPA. Results are reported in table 1, The results for E0 - E10 indicate that there is pass-through on average, consistent with earlier findings (e.g., Knittel et al. (2017)). It is worth noting, however, that the point estimate is 0.123, which indicates that contemporaneous product pricing reflects only 12.3% of RIN variation. The wide variation in the ability of sellers to affect product pricing means that there is not a statistical difference between 12.3% and 100%, even as there is a large commercial difference.

Table 1: Pass-Through Estimates without Weekends

	E0 - E10	B0 - B2	B0 - KERO/JET
	0.123	-0.034***	1.574***
	(0.799)	(0.013)	(0.059)
N	3,977	1,902	1,172

Each column reports β coefficient from a separate regression of equation 2 with the dependent fuel price spread listed at the top of the column. Regressions also include seasonal, facility, and volume controls that are not reported. Standard errors in parentheses are Newey-West, allowing for autocorrelation. Stars indicate whether the hypothesis that the parameter is equal to 1 is rejected, with $*p < 0.1, **p < 0.05, ***p < 0.01$.

The B0-B2 diesel spread has not been estimated elsewhere and may be too tight to provide meaningful inference, but does not show evidence of pass-through. The point estimate is very close to zero and is significantly different from one. This suggests that the price differential between B0 and B2 does not reflect changes in RFS compliance costs.

The ULSD-KERO/JET spread shows evidence of pass-through (coefficient 1.574 and significantly greater than 1), though there may be physical differences and segmented markets that account for that difference. Buyers of jet fuel cannot substitute to diesel (and vice versa) the way most buyers of E0 and E10 can substitute between the two. Note that pooling across all fuels (like Knittel et al. (2017)) would indicate that there is near-complete pass-though on average.

For all three fuel spreads the volumetric controls are statistically significant and negative for all specifications reported in tables 1 and 2. This suggests that there may be relevant economies of scale. The estimates reported here control for that effect.

The second set of results estimate equation 2 for each of three fuel spreads using the data that include weekends. The results indicate that there is less evidence of pass-through when weekend transactions are included. Notably, the results presented in table 2 suggest that the degree of pass-through in the gasoline market is significantly different from 1. The results for the diesel spreads do not change substantively when weekends are included—the degree of pass-through is significantly different from complete and immediate.

The point estimate and large confidence interval when including interpolated RIN obligation data over weekends draws into question the relevance of ratable compliance assumptions, because trading arrangements for RINs are substantially less liquid on weekends, and waiting until the next weekday may expose obligated parties to price risk inherent to

compliance. EPA expressly ignores such a pathway as being "caused by RFS."

Table 2: Pass-Through Estimates with Weekends

	E0 - E10	B0 - B2	B0 - KERO/JET
	-0.789**	-0.027***	1.630***
	(0.747)	(0.016)	(0.096)
N	5,246	2,630	1,672

Each column reports β coefficient from a separate regression of equation 2 with the dependent fuel price spread listed at the top of the column. Regressions also include seasonal, facility, and volume controls that are not reported. Standard errors in parentheses are Newey-West, allowing for autocorrelation. Stars indicate whether the hypothesis that the parameter is equal to 1 is rejected, with $*p < 0.1, **p < 0.05, ***p < 0.01$.

Table 3: Pass-through Estimates by PADD (with Weekends)

	E0 - E10	B0 -B2	B0 - KERO/JET
PADD 1	-7.461***	-0.044***	
	(2.909)	(0.017)	
PADD 3	-1.631***	0.045***	0.535
	(0.582)	(0.031)	(0.747)
PADD 4	3.278**		1.686***
	(0.896)		(0.105)
PADD 5	12.352***		1.469*
	(1.604)		(0.239)

Each column reports β coefficient from a separate regression of equation 2 with the dependent fuel price spread listed at the top of the column. Regressions also include seasonal, facility, and volume controls that are not reported. Standard errors in parentheses are Newey-West, allowing for autocorrelation. Stars indicate whether the hypothesis that the parameter is equal to 1 is rejected, with $*p < 0.1, **p < 0.05, ***p < 0.01$.

The third set of results explore differences in pass-through by PADD using similar approaches to those reported in table 2. These are reported in table 3. In all but one case,

the hypothesis that pass-through is complete and immediate is rejected. Taken together, the results indicate widely varying conditions around the country. Weekends are included here to bolster sample sizes as the transactions data are divided to explore regional heterogeneity. This may be asking too much of the data, as the number of observations for each regression dips as low as 92. More transactions, potentially over a longer time period, are needed to remedy this fault. The results can be taken as illustrative of the variation that accumulates in the fuels supply chain in different regions, but should not be regarded in the same light as the pooled regressions.

Conclusions

1. These specifications account for differences in pass-through due to volume effects. Larger sales lots consistently and significantly receive higher prices, and the differences also appears to be commercially significant. While economies of scale are likely present in oil refining and bulk fuel sales, this isolation of this effect in the context of RFS compliance is relevant to the statutory allowance for SRE. It also isolates all remaining variation as directly attributable to RIN cost variation, having controlled separately for size effects.

2. In this sample of sales by small refineries, pass-through rates appear to be lower and more variable than in larger samples such as Knittel et al. (2017). For example, the gasoline pass-through coefficient in table 1 falls by nearly 30 percent when weekends are included in table 2. Neither coefficient is significantly different from 1 because there appears to be wide variation in the extent to which pass-through is occurring.

3. Excluding weekends appears to overestimate estimates of pass-through, with less pass-through when weekends are included. This is relevant to discussions of ratable compliance, because RIN markets are likely not as liquid during weekends for lack of price discovery and deepness of the market.

4. Pass-through varies substantially across fuels. This is evident from the analysis of one bulk gasoline and two bulk distillate spreads, which yield substantively different estimates pass-through, and is consistent with earlier work on this topic.

5. There appears to be substantial variation in pass-through by region, and by fuel. These estimates are straining the available data and should be taken as suggestive rather than definitive.

6. Variation in estimates of pass-tough suggests that EPA's assumption of complete, immediate, and comprehensive pass-through does not hold in all cases.

References

Knittel, Christopher R, Ben S Meiselman, and James H Stock, "The pass-

through of RIN prices to wholesale and retail fuels under the renewable fuel standard," *Journal of the Association of Environmental and Resource Economists*, 2017, *4* (4), 1081–1119.

Lade, Gabriel E and James Bushnell, "Fuel subsidy pass-through and market structure: Evidence from the renewable fuel standard," *Journal of the Association of Environmental and Resource Economists*, 2019, *6* (3), 563–592.

Comments on EPA Proposed RFS Small Refinery Exemption Decision

Timothy Fitzgerald

I offer four major comments regarding the economic analysis presented in the Proposed RFS Small Refinery Exemption Decision.

1. Academic literature does not support the competitive market assumption asserted by EPA
2. EPA ignores jointness of production and implications for compliance
3. Competitive model asserted by EPA makes claims about market share ambiguous
4. EPA failed to provide evidence to substantiate the assumption of ratable RIN compliance

Detail of each of these issues follows.

1. Academic literature does not support the competitive market assumption asserted by EPA

EPA makes a strong assertion that "all obligated parties recover the cost of acquiring RINs by selling the gasoline and diesel fuel they produce at the market price, which reflects these RIN costs (RIN cost passthrough)." (p26 IV.D.2) As stated, this claims that all transactions fully recover RIN costs. EPA maintains this position throughout the proposed decision. This claim is not consistent with the empirical results relevant to this issue in the academic literature. EPA is relying too heavily on a very small number of results and making an interpretation that is unduly strong given the entire available empirical record. EPA has chosen its interpretation, but in so doing ignores complementary evidence that helps paint a more complete picture of how RFS compliance is achieved by different obligated parties.

a. EPA bases its review of the academic literature on a single study

EPA bases its position on single academic study (Knittel et al., 2017) and the working paper version of the published article that examined data from a subsequent period.[1] One other EPA document is also cited,[2] but only the single external study is cited in support of EPA's interpretation. While the Knittel et al. (2017) study is indisputably and influential study in this area, it is not the only work on the work in this area, and even taken by itself it does not fully support the position that EPA has elected to take.

b. EPA makes an overly strong interpretation of Knittel et al. (2017) results

Knittel et al. (2017) infer economic pass-through from a series of statistical tests on a collection of major wholesale fuel price spreads. While the statistical results are consistent with the notion that wholesale price spreads reflect changes in the calculated RIN obligation *on average*, it is a substantial leap to suggest that this happens in all cases. While the best guess in any particular case is that the obligation is passed through within a couple business days, and a vast majority of cases will be characterized by complete pass-through, that does not mean that every particular instance will be fully passed through in that timeframe.

[1] Knittel, C.R., Meiselman, B.S., and Stock, J.H. 2017. The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard. *Journal of the Association of Environmental and Resource Economists* 4(4), 1081-1119. The working paper examining subsequent data: Knittel, C.R., Meiselman, B.S. and Stock, J.H., 2016. The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard: Analysis of Post-March 2015 Data. Working Paper.

[2] Burkholder, D., 2015. A preliminary assessment of RIN market dynamics, RIN prices, and their effects. Office of Transportation and Air Quality, US EPA.

EPA's interpretation appears to be most consonant with the pooled results reported in table 3 of Knittel et al. (2017), but even in that case the standard error of the pooled estimate is not zero and gasoline and diesel evidence different pass-through. Even the closely estimated pooled result allows for variation around the point estimate. EPA ignores the proper statistical interpretation of the only external study that it cites by claiming that there is complete and immediate pass-through in all cases in all submarkets.

c. Other studies provide strong evidence for imperfect pass-through

The substantial academic literature that provides evidence of imperfect pass-through undermines EPA's chosen interpretation. Lade & Bushnell (2019) is one such study,[3] concluding that between half and three-quarters of the RIN cost is passed through to E85 prices. It is worth noting that this occurs over the substantially longer period of 6-8 weeks rather than two business days. Even while allowing for the possibility of complete pass-through on average, this result undermines the position that EPA has taken in the proposed decision. The results contrast subtly with the long-run pass-through model of Knittel et al. (2017) and provides more recent empirical support for the conclusion presented by Pouliot and Babcock (2016) that short-run compliance costs for obligated parties can be substantial.[4] Lade and Bushnell (2019) highlight the heterogeneity in pass-through in part depending on market size and integration of retail.

[3] Lade, G.E. and Bushnell, J., 2019. Fuel subsidy pass-through and market structure: Evidence from the renewable fuel standard. *Journal of the Association of Environmental and Resource Economists*, *6*(3), 563-592.
[4] Pouliot, S. and Babcock, B.A., 2016. Compliance path and impact of ethanol mandates on retail fuel market in the short run. *American Journal of Agricultural Economics*. *98*(3), 744-764.

The Lade and Bushnell (2019) result of less than full pass-through to E85 is consistent with the result from Li and Stock (2019),[5] which used a different dataset and concluded that pass-through depends on the depth of the market for E85. Introducing the geographic variation in pass-through underscores that some assets in transportation fuel supply are not fully flexible in the short run, and hence compliance costs can differ across obligated parties.

Because E85 is the only finished fuel that can absorb additional required volumes of biofuels in the gasoline markets beyond standard oxygenate requirements, the slow and incomplete pass-through indicates that the marginal gallon of biofuel in transportation fuel may not be passed through as smoothly as inframarginal gallons are. Indeed, for RVOs below a traditional E10 blend, RINs did not have substantial economic value because blenders voluntarily chose to blend biofuels to enhance fuel performance and meet other requirements. Only after EPA increased RVOs beyond the blend wall was the financial incentive of the RIN needed to promote additional or excess blending of biofuels into the transportation fuel supply. The disparity in the retail gasoline market can explain the divergence between empirical estimates of average and marginal pass-through.

Burkhardt (2019) presents further useful results by studying margins across which pass-through varies.[6] The aggregate pass-through result corroborates the Knittel et al. (2017) result of pass through on average, with a tighter relationship estimated in gasoline markets as opposed to diesel markets. The size of the obligated parties and the region of the country where obligated parties are located affect the pass-through relationship. These results are important because they show

[5] Li, J. and Stock, J.H., 2019. Cost pass-through to higher ethanol blends at the pump: Evidence from Minnesota gas station data. *Journal of Environmental Economics and Management*, *93*, 1-19.
[6] Burkhardt, J., 2019. The impact of the Renewable Fuel Standard on US oil refineries. *Energy Policy*, *130*, 429-437.

that average pass-through can mask relevant variation in the ability of obligated parties to recover RIN costs.

Further evidence that the complicated structure of the fuel supply sector may affect pass-through comes from Pouliot et al. (2017),[7] which documents the variation in pass-through at gasoline terminals depending on the number of products offered and the region of the terminal. In particular, there is evidence that pass-through does not occur on the East Coast, and data from the West yields imprecise estimates of pass-through. These results corroborate the findings in Burkhardt (2019) that pass-through on average can mask local or specific instances where the mechanism does not operate in the same way. The results from the West also suggest that evidence of pass-through at one time does not necessarily mean there will be pass-through in a different time period.

Ignoring the substantial evidence from other academic papers that pass-through is imperfect further undermines the strongly competitive interpretation that EPA has elected to make based on results from a single external study. In light of the fact that many of these studies have a similar finding that pass-through does occur on average, but there are circumstances in which pass-through is incomplete; EPA could consider the implications for the assertion that the RIN market is everywhere and always competitive.

d. National policies increase pass-through on average, but also pass-through heterogeneity

Recent research indicates pass-through depends on the nature of cost shocks. In work that addresses pass-through of price shocks in the oil refining sector, but does not address RINs

[7] Pouliot, S., Smith, A. and Stock, J.H., 2017. RIN pass-through at gasoline terminals. Working Paper.

explicitly, Muehlegger and Sweeney (2021) find evidence of variable pass-through.[8] This work helps resolve a standing economic puzzle about pass-through. If compliance costs vary across firms, then the extent of pass-through will also vary. If compliance costs are uniform, then the pass-through across the industry is likely to be comparable. The model and matching results in Muehlegger and Sweeney (2021) suggest that pass-through does vary across relevant margins. This suggests that compliance costs—costs directly attributable to RFS—may also vary in statistically and economically significant ways across firms. These important results from the same industry deserve consideration for firms that bear a higher-than-average share of costs, which could be restated as "disproportionate economic harm" directly attributable to the RFS.

More pointedly, Muehlegger and Sweeney (2021) demonstrate that increasing pass-through on average (such as shown by Knittel et al. (2017)) also increases the variation in ability to pass-through costs across firms within the industry. If EPA recognizes that RFS is a national policy affecting all firms, then it must also recognize that this increases heterogeneity in the ability of firms to pass-through higher costs, introducing the possibility that some firms are disproportionately affected by the program

To conclude, the strong assertion by EPA overstates the empirical record, in particular where the academic literature has documented examples of differences in pass-through across various margins. Recent results about the tradeoff between average pass-through and pass-through heterogeneity are especially relevant but ignored by EPA.

[8] Muehlegger, E. and Sweeney, R.L. 2021. Pass-Through of Own and Rival Cost Shocks: Evidence from the U.S> Fracking Boom. *Review of Economics and Statistics.* Forthcoming.

2. EPA ignores jointness of production and implications for compliance

Because of RIN convertibility, firms can choose how to comply with RFS requirements, though not all strategies taking advantage of convertibility are likely to be advantageous. Obligated parties understand the nesting and overall cap, but the assumption that transportation fuels markets are strongly separable ignores the linkage provided by RFS and the jointness in production that may limit ability to alter obligations, even over an extended time horizon. EPA ignores these issues in the proposed decision rule and simplifies its narrative of the industry. This is starkly exhibited in the expression of Equations (1) and (2) in the proposed decision rule.

a. EPA ignores recent academic literature suggesting that the marginal RIN is D4

Irwin et al. (2020) provide evidence that factors related to policy interactions complicate RIN price dynamics.[9] Specifically, the peripatetic authorization of the biomass-based diesel tax credit has introduced policy uncertainty to the nested structure of RIN compliance. In practical terms, this means that it can be cheaper and easier to comply with the RFS by paying for a D4 RIN that tracks the higher production cost of biodiesel relative to petroleum-based diesel than it is generate additional D6 RINs by blending E85 that must be sold at an uncertain discount.

This development differs from the model presented in figure 4 in Knittel et al. (2017), which presumes separation between the D4 and D6 RINs. Put another way, when the D4 subsidy is sufficiently small, obligated parties can reduce costs by surrendering D4 rather than D6 RINs. But the difficulty that EPA faces in anticipating regulatory regimes when setting RVOs means

[9] Irwin, S.H., McCormack, K. and Stock, J.H., 2020. The price of biodiesel RINs and economic fundamentals. *American Journal of Agricultural Economics*, *102*(3), pp.734-752.

that there can be both persistent and volatile spreads in D4 RINs that can provide a time-dependent fluctuation in compliance costs.

b. Linkages between fuels markets limit flexibility for specialized obligated parties

Refiners accrue obligations based on refinery throughput, which is determined in part by configuration. Refinery configurations can change with investment over time but may be fixed in the short term. As an example, an obligated party producing mostly diesel fuel will not have the option to blend to separate RINs for compliance and is forced to purchase D4 RINs to meet the RVO. Given that diesel markets exhibit less pass-through on average than gasoline markets, this may limit the ability to recover costs. Conversely, a gasoline-heavy obligation can try to enter the blending market to take advantage of separation, or exploit nesting to use wither D6 or D4 RINs as prices allow.

EPA could present a joint model of equations that would reflect the jointness in compliance created by RIN convertibility and physical limitations that exist in the short run. If EPA conceives of Equations (1) and (2) as long-run conditions, that should be explicit. Constraints on adjustment between the short run (cf. Pouliot and Babcock (2016)) and EPA's view of industry dynamics in the long run exist and are uneven across regions and firms. This creates potential for disproportionate economic harm.

3. Competitive model asserted by EPA makes claims about market share ambiguous

EPA asserts that the underling RIN market is competitive and that pass-through is complete and immediate in all cases. It further typifies the transportation fuels market as "highly competitive" (p26 IV. D. 2.) both in terms of refining and fuel blending. Given this assertion, it is peculiar that EPA focuses on the dynamic by which "competitors will give up the revenue from the sale of RINs to gain a greater market share" (p35, IV.D.2.b.) because market share would not seem to be a valuable end to itself in a highly competitive market.

There are possible explanations for the focus on market share in a competitive setting, such as developing or enhancing local market power or costs that depend on share or volume. It is not clear from the brief mention of market share which, if any, of these channels EPA has in mind.

The most intuitive explanation is that there are varying degrees of local or regional market power, and obligated parties seek to develop and exploit such power. This reality contrasts starkly with EPA's assertion that refined products are competitive and always and everywhere facilitate pass-through of RFS compliance costs for all parties.

4. EPA has failed to provide evidence to substantiate the assumption of ratable RIN compliance

EPA relies on the notion that if obligated parties comply with RFS requirements by acquiring RINs as obligations accumulate—which is termed *ratable* compliance—then the obligated parties will be assured of meeting RFS requirements. EPA goes a step further by suggesting that any non-ratable compliance strategy cannot be the basis for disproportionate economic harm. EPA has the means to provide evidence on this front, which has been lacking to date.

a. Academic literature indicates that timing of pass-through varies

EPA relies on the Knittel et al. (2017) result that RIN obligations are reflected in fuel prices on average within about two business days. As mentioned above, other studies indicate that the period for pass-through can be substantially longer. Lade and Bushnell (2019) find that pass-through to E85 prices can take as long as six to eight weeks on average. Burkhardt (2019) uses monthly data in assessing pass-through. Pouliot et al. (2017) use weekly data in assessing pass-through at gasoline terminals, finding that multiple regions of the country do not show signs of pass-through in that time period. If pass-through varies in time, then an obligated party would want to match its compliance strategy with the timing of pass-through. EPA has made a strong assumption about the timing of pass-through that ignores differing results in the literature.

Given these differing results, which vary by product and region, it would be understandable for obligated parties to match their compliance strategy with the timing of pass-through in the markets most relevant to their operations. EPA apparently does not agree, stating "all obligated parties have the ability to match their RIN costs with the price they receive when they sell their fuel (i.e., to pass through their RIN costs)." (p49. IV.D.2.d.i.) If empirical results indicate that pass-through is not immediate, then ratable compliance will necessarily force an obligated party to hold an uncovered position in the RIN market. EPA regards this behavior as speculation, and "EPA strongly disputes that costs resulting from an individual refinery's business decisions…represent DEH *caused* by the RFS program." [emphasis original] (p49 IV.D.2.d.i.) EPA claims that all compliance should be ratable yet chooses to ignore evidence of differences in timing of pass-through that would lead obligated parties to make decisions about RINs over longer time periods. This inconsistency could lead an obligated party to try to ratably comply yet

not receive complete pass-through because of fluctuations in RIN or fuel markets over a longer time required for pass-through to occur in certain product or regional markets. Such situations cast doubt on EPA's assertion that trading activity to comply with the RFS cannot cause disproportionate economic harm.

b. Academic literature assumes ratable compliance, but price dynamics matter

How RIN prices vary has attracted substantial attention. Mason and Wilmot (2016) account for the effect of price jumps in the RIN market,[10] and underscore the importance of this modeling assumption in understanding price behavior. This becomes significant because of the underlying presumption that firms are able to pass price changes through to customers. If price dynamics are such that RIN prices jump while an obligated party is holding RINs and waiting for those costs to pass-through to product markets, the obligated party could be exposed to unwitting and unwelcome price risk. Yet EPA claims that such an event would be speculation on the part of the obligated party. The position staked out by EPA ignores recognized price dynamics that put an obligated party in an impossible situation.

Two factors are relevant to this issue. One is liquidity in the RIN market. EPA asserts that "RINs are widely available in an open and liquid market" (p26, IV.D.2.), but does not quantitative metrics of that liquidity. Providing evidence of the market liquidity in all RIN categories across time periods would help reduce concerns about illiquidity as a cause of disproportionate economic harm because of the RFS program.

[10] Mason, C.F. and Wilmot, N.A., 2016. Price discontinuities in the market for RINs. *Journal of Economic Behavior & Organization*, *132*, pp.79-97.

A second issue is the costs of transaction, and particularly how those might vary across firms. The Burkholder memo address the issue of transactions within and between firms being fundamentally the same (p6), but does not explore potential cost differences. Providing evidence on this issue would help reduce concerns about this channel for disproportionate economic harm as a result of the RFS program. Reports of RIN generation provided by the EMTS program report overall caps but do not differentiate between RINs that remain within one firm and those that change hands between parties.

c. EPA has conducted analyses that are not shared

EPA repeatedly refers to "analyses" it performed (e.g., p44, IV.D.2.d.) but there is no transparency to evaluate the methods by which EPA has reached its conclusions. There is no description of data or empirical methodology, nor are results provided. Instead, EPA provides only conclusions. It is possible for EPA to share more detail about additional analyses that bear on the decision. To the extent that these analyses use different models or data than publicly-available results, sharing the analyses would improve understanding and improve transparency.

d. EPA has data that could demonstrate ratable compliance

EPA's argument about RIN compliance relies heavily on the ratable basis for compliance. EPA clearly states that any EPA does have access to RIN logs, which could be used to demonstrate that obligated parties have similar compliance patterns and costs. While providing the raw data might not be practical for confidentiality concerns, EPA could do more to provide transparency

about analyses and key results. As it stands today, EPA is relying on a single external study and one internal memo from 2015.

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August–December 2007–2008

EDUCATION

Ph.D., Agricultural and Resource Economics, University of Maryland, January 2009
Dissertation Title: *Essays on Split Estates in Energy Development*
A.B., *summa cum laude* in Economics and Environmental Studies, Bowdoin College, 1997

PUBLICATIONS

Refereed Journals

Fitzgerald, Timothy and Michael Giberson. *2021.* Wind Project Performance with Age: Policy, Technology, Markets, and the Maturing Wind Power Industry. *The Electricity Journal*. 34(10): 107047.

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Other Publications

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McGowen, Patrick, Jaydeep Chaudhari, Brian Church, Janelle Booth, Timothy Fitzgerald, Daniel Richter, and Robert J. Eger III. 2011. Montana Fuel Tax Refunds: Final Report. Western Transportation Institute, Bozeman, MT.

Fitzgerald, Tim. 2000. Federal Land Exchanges: Let's End the Barter. *PERC Policy Series* #18. PERC: Bozeman, MT.

Current Working Papers

Whose Frac is It, Anyway? Using Innovations to Explain Industrial Organization in Oilfield Services (with Charles F. Mason)

The Economic Costs of Green Recovery Plans (with Casey B. Mulligan)

The Environmental Costs of the Jones Act

Regulatory Capture in a Resource Boom

The Effects of Oil and Gas Fiscal Regimes on Exploration and Production Decisions (with Andrew Stocking)

Achieving Negative Carbon Leakage through Sectoral Border Adjustment Reductions

Permanent Working Papers

The effects of Biden's tax and regulatory agenda on long run economic activity (with Kevin Hassett, Casey B. Mulligan, and Cody Kallen) *2020*

Protecting Rhinos through Legal Horn Trade (with Michael t' Sas-Rolfes) *2013*

FELLOWSHIPS AND AWARDS

Nonresident Fellow, American Center for Capital Formation, 2019
John V. Krutilla Research Fellow, Resources for the Future, 2012–2013
Meridian Institute Conservation Leadership Partnership Fellow, 2012
Lone Mountain Fellow, Property and Environment Research Center, 2012, 2016
Noyes Political Economy Prize, Bowdoin College, 1997
Surdna Foundation Undergraduate Research Fellowship, 1996–1997

GRANTS

Hayek Fund for Scholars, Institute for Humane Studies, 2020
USDA NIFA AFRI, Effects of Oil and Gas Development on Agriculture, 2014–2019
Faculty Excellence Grant, Montana State University, 2013–2014
Faculty Development Award, Montana State University, 2011
Research Enhancement Award, MSU Letters & Sciences, 2009–12
Jacob Goldhaber Travel Grant, University of Maryland, 2007

PRESENTATIONS

Invited

2020 Air Force Academy; Bowdoin College (postponed); Cornell University (Dyson).
2019 University of Tennessee; Baylor University.
2017 Dallas Federal Reserve; Texas Christian University; Texas Tech University (AAEC).

Conference

2021 AERE Virtual Summer Conference; IEW Workshop, Freiburg, DE; CU Environmental and Resource Economics Workshop, Vail, CO; Energy Policy Conference, Boise, ID; USAEE/IAEE Virtual Conference.

2020 Rice Center for Energy Policy, Houston, TX; Hoover Institution, Stanford, CA (postponed); AERE Virtual Summer Conference; 40th OECD Round Table on Sustainable Development, Paris, FR.

2019 AERE Summer Conference, Lake Tahoe, NV; EMEE Workshop, Quebec City, QC; JPMCC International Workshop, Denver, CO; USAEE/IAEE North American Conference, Denver, CO; NU-CMU Energy Workshop, Chicago, IL; Southern Economics Association, Ft. Lauderdale, FL.

2017 ASSA Annual Meeting, Chicago, IL; AERE Summer Conference, Pittsburgh, PA; SIOE Conference, New York, NY.

2016 ASSA Annual Meeting, San Francisco, CA; Center for Energy Studies, Houston, TX; AERE Summer Conference, Breckenridge, CO; CAES-WAEA Joint Annual Meeting, Victoria, BC; USAEE /IAEE Conference, Tulsa, OK.

2015 AAEA-WAEA Joint Annual Meeting, San Francisco, CA; 17th Annual University of Colorado Environmental and Resource Economics Workshop, Vail, CO; 34th USAEE/IAEE Conference, Pittsburgh, PA; Southern Economics Association Meeting, New Orleans, LA.

2014 ASSA Annual Meeting, Philadelphia, PA; Unconventional Gas and Oil Development Workshop, Morgantown, WV; Western Economic Association Annual Conference, Denver,

CO; NBER EEE Summer Institute, Cambridge, MA; CREE Annual Meeting, Saskatoon, SK; National Tax Association, Santa Fe, NM.

2013 Big Sky Energy Forum, Billings, MT; AERE Summer Conference, Banff, AB; WAEA Annual Meeting, Monterey, CA; Western Economic Association Annual Conference, Seattle, WA; CESifo Venice Summer Institute, Venice, IT; 32nd USAEE/IAEE Conference, Anchorage, AK; 14th Occasional California Workshop in Environmental and Resource Economics, Santa Barbara, CA.

2012 ASSA Annual Meeting, Chicago, IL; Providing Environmental Services from Agriculture Conference, Washington, DC; Congressional Budget Office, Washington, DC; WAEA Annual Meeting, Park City, UT; 31st USAEE/IAEE Conference, Austin, TX.

2011 30th USAEE/IAEE Conference, Washington, DC; CAES-WAEA Joint Annual Meeting, Banff, AB; 13th Annual University of Colorado Environmental and Resource Economics Workshop, Vail, CO.

2010 29th USAEE/IAEE Conference, Calgary, AB.

Other Workshops

2021 NBER Economics of Energy Innovation (invited); NBER New Directions in Transport Economics; EMEE Virtual Conference; J.P. Morgan Center for Commodities Annual Research Workshop; Annual Conference on Innovation Economics.

2020 Workshop on Gas Flaring, Austin, TX (participant); NBER Economics of Transportation and Infrastructure in the 21st Century (participant); CEBRA Workshop on Commodities and Macroeconomics; FRB Richmond Climate Workshop (invited); Dallas and Kansas City Fed's Energy and the Economy Conference (invited).

2019 Oil & Gas Volatility Workshop, Golden, CO (panelist); Breakthrough Dialogue, Sausalito, CA (panelist); International Commodities Symposium, Denver, CO (panelist); Texas Stata Microeconometrics Workshop, Houston, TX (attendee).

PROFESSIONAL ACTIVITIES

Editorial

Advisory Board, *Energy Research Letters*, 2020–present
Book Review Editor, *The Energy Journal*, 2017–present

Reviewer

American Economic Journal: Economic Policy, *Ecological Economics*, *Economic Inquiry*, *Energy Economics*, *Energy Journal*, *Energy Policy*, *Journal of the Association of Environmental and Resource Economists*, *Journal of Environmental Economics and Management*, *Journal of Law & Economics*, *Journal of Political Economy*, *Land Economics*, *Regional Science and Urban Economics*, *Resource and Energy Economics*, *Review of Environmental Economics and Policy*

The Secretary of Energy
Washington, D.C. 20585

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February 25, 2009

The Honorable Lisa P. Jackson
Administrator
Environmental Protection Agency
Washington, D.C. 20004

Dear Administrator Jackson:

Section 211(o)(9)(A)(ii) of the Clean Air Act, as revised by the Energy Policy Act of 2005 (EPACT 2005), requires that the Department of Energy (DOE) conduct a study for the Administrator of the Environmental Protection Agency (EPA) assessing whether the renewable fuel standard (RFS) would impose a disproportionate economic hardship on small refineries, defined as those facilities with capacities under 75,000 barrels per calendar day.

Small refineries encompass a diverse range of businesses. Some will be able to generate credits through blending renewable fuels into their products; others may choose to purchase such credits from parties that over comply with the standards. There appears to be no shortage of credits available under the current RFS; the market appears to be liquid and competitive. While the Energy Independence and Security Act of 2007 (EISA) increased the volume and added additional categories of renewable fuel, there is no basis at this time to believe that the character of markets for credits will fundamentally change. While credit prices may increase, DOE has no reason to believe that a competitive market would disproportionately disadvantage participants who purchase credits rather than generate them through blending renewable fuels into their products. Therefore, DOE believes that the exemption for small refineries should not be extended at this time. Should markets change; small refineries maintain the right under EPACT 2005 to petition EPA for individual extensions of the exemption.

Please find enclosed our study presenting DOE'S findings and explaining why DOE does not believe that the extending the exemption for small refineries beyond 2010 is warranted at this time. Should you have any questions, please call Ms. Carmen Difiglio at (202-586-8436).

Sincerely,

Steven Chu

Enclosure

Printed with soy ink on recycled paper

EPACT 2005 Section 1501
Small Refineries Exemption Study

Office of Policy and International Affairs

U.S. Department of Energy

January 2009

Small Refinery Exemption Study

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Executive Summary

The Energy Policy Act of 2005 (EPAct 2005) established a Renewable Fuel Standard (RFS) under Section 211(o) of the Clean Air Act (CAA), requiring the incorporation of renewable fuel, such as ethanol, in the transportation fuel mix. EPAct 2005 also exempted certain small refineries from compliance with the RFS through 2010. Under Section 211(o)(9)(A)(ii) of the CAA, DOE is required to determine if compliance with the RFS would impose a "disproportionate economic hardship" on small refineries, and convey to the Environmental Protection Agency (EPA) by December 31, 2008, whether the exemption should be extended past 2010.

Under certain scenarios small refineries using the exemption may realize significant economic benefits if they are not required to participate in the RFS program, either by the blending of renewable fuels or the selling of products that have lower production costs than their competitors. Such a scenario could encourage inefficient capital investments in the refinery industry. This study does not assess the potential for disproportionate economic advantages in extending the exemption for small refineries, nor would this be a basis for rejecting the extension of the exemption under Section 211(o)(9)(A)(ii).

Obligated parties, such as refineries, may fulfill their renewable fuel requirements through either blending renewable fuels into their products or purchasing credits from other parties who have exceeded their allocation of renewable fuel consumption. Thus, even if a refinery is limited through geography or lack of capital in its ability to generate credits by blending renewable fuels into its products, it may purchase credits from other parties. As long as credits are available for purchase and the market is competitive, small refineries should not be subject to disproportionate economic hardship from their choice to purchase credits rather than to generate them. Should market conditions change such that small refineries face disproportionate economic hardship, they may still petition the EPA for an extension of their exemption past the statutory date of December 31, 2010.

This study examines the current market for credits and projections for their future price and availability. At the present time, credits are available at a nominal value and compliance volumes have been in excess of the RFS requirements. Under these conditions, it does not appear that small refineries would be subject to disproportionate hardship by the RFS mandate if they are required to participate in the program. Additionally, the RFS legislation contains flexibility provisions that allow EPA to reduce the RFS volumetric requirements and issue Renewable Identification Numbers (RINs) to ensure that limits do not exceed industry's ability to supply renewable fuels or that implementation of the requirements would severely harm the economy or environment. Therefore, DOE concludes that the RIN market is likely to be competitive and that small refineries will not face disproportionate economic harm by their participation in the RFS program.

Introduction

Section 1501 of the Energy Policy Act of 2005 (EPAct 2005) amended Section 211 of the Clean Air Act (CAA) by adding Section 211(o), which required the Environmental Protection Agency (EPA) to promulgate regulations implementing a renewable fuels program. EPAct 2005 specified that the regulations must ensure that a specified volume of renewable fuel be used in gasoline sold in the U.S. each year, with the total volume increasing over time. The goals of the program include reducing the Nation's dependence on foreign sources of petroleum, increasing domestic sources of energy, and assisting in the transition to alternative fuels from petroleum in the transportation sector.

The final Renewable Fuel Standard (RFS) program rule was published on May 1, 2007, and the program began on September 1, 2007[1]. The Renewable Fuel Standard, as specified by the 2007 Final Rule, will be referenced as RFS1 in this document. RFS1 created a specific annual level for minimum renewable fuel use that increases

[1] During 2006 a Renewable Fuel Standard was established using the default compliance criteria as specified by EPAct 2005.

over time – resulting in a requirement that 7.5 billion gallons of renewable fuel be blended into gasoline (for highway use only) by 2012. Under the RFS1 program, compliance is based on obligated parties meeting their annual Renewable Volume Obligation (RVO) (published annually in the Federal Register by EPA). Obligated parties include refiners, blenders and importers of gasoline. The RVO is expressed as a percentage of total non-renewable gasoline sold by the obligated party in the specified calendar year. Compliance is demonstrated through the use of Renewable Identification Numbers, or RINs, a 38-digit serial number assigned to each batch of renewable fuel produced. For obligated parties (those who must meet the annual volume percent standard), RINs must be acquired either by blending renewable fuel into gasoline or diesel to show compliance or by acquisition of RINs from other parties that have exceeded their RVO.

The Small Refinery Exemption

Section 211(o)(9)(A)(i) of the CAA exempts small refineries from the RFS1 requirements until the 2011 compliance period. Small refineries are defined under Section 211(o)(9)(A)(ii) of the CAA as refineries with average annual crude input below 75,000 barrels per day. Appendix A contains a list of candidate small refineries that meet the exemption criteria using the Energy Information Administration's (EIA) operable refinery capacity data from form EI-810, the Monthly Refinery Report. This list is merely illustrative, as additional refineries may meet the exemption criteria if their annual operations are significantly lower than their reported operable capacity.

In preparation for the RFS1 rulemaking, EPA convened a Small Business Impact (SUBREFA) panel to examine the impact of the RFS1 on small businesses. Subsequent to the discussions of the SUBREFA panel, EPA chose to exempt small refiners, defined as refiners producing gasoline from crude oil with fewer than 1,500 employees and less than 155,000 barrels per day crude processing capability, as well as small refineries as defined above, from the RFS1 mandate through 2010. Some small refineries belong to large integrated energy companies which do not meet the

criteria for small refiners, while some small refiners have refineries over 100,000 barrels per day capacity which would not qualify for the small refinery exemption. EPA has tentatively concluded that it does not have the authority to extend the duration of the exemption period for small refiners as defined under the RFS1 rulemaking[2]. The statute permits the extension of the exemption period for small refineries as defined in Section 211(o)(9)(A)(ii) of the CAA beyond its current expiration date of 2010. This report only evaluates the class of small refineries as directed under Section 211(o)(9)(A)(ii) of the CAA.

Extending the Small Refinery Exemption

Congress specifically addressed the potential for an extension of the small refinery exemption in EPAct 2005. Under section 211(o)(9)(A)(ii) of the CAA, the Secretary of Energy is required to conduct a study for the EPA Administrator to determine whether compliance with the RFS1 would impose a disproportionate economic hardship on small refineries, defined as those facilities with capacities under 75,000 barrels per calendar day. If the study found that a disproportionate economic hardship would occur, EPA is obligated to extend the RFS1 exemption for at least two additional years. In addition, refineries still maintained the right to petition EPA for individual exemption from the program.

Under certain scenarios, small refineries using the exemption might gain significant economic benefits through blending renewable fuels or selling products that have lower production costs than their competitors if they are not required to participate in the RFS program. Such a scenario could encourage inefficient capital investments in the refinery industry. This Study does not assess the potential for disproportionate economic advantages in extending the exemption for small refineries, nor would this be a basis for rejecting the extension of the exemption under Section 211(o)(9)(A)(ii) of the CAA.

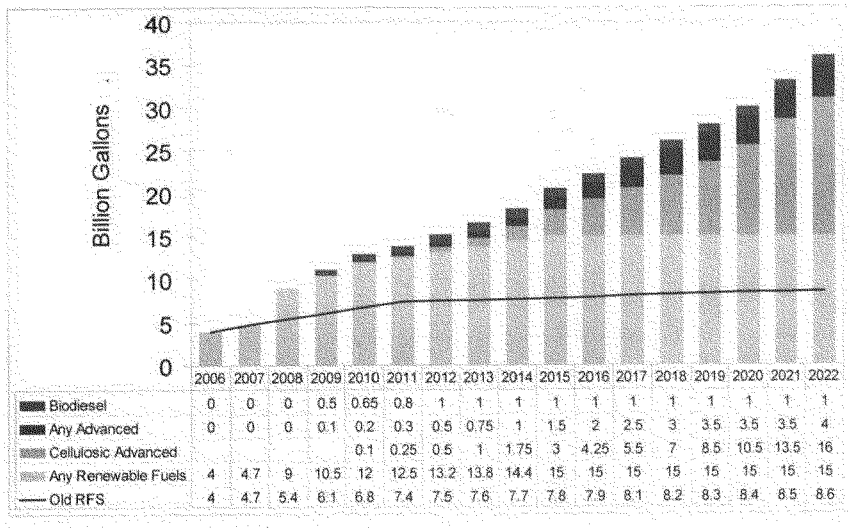
[2] "Final Report of the Small Business Advocacy Review Panel on EPA's Planned Proposed Rule Regulation of Fuels and Fuel Additives: Renewable Fuel Standard Program", September 5, 2008.

The Impact of EISA 2007 on the DOE study

While the underlying program structure is not expected to change, EISA revised and extended the RFS1 fuels volumes required under EPAct 2005. The revised program, referred to as RFS2, requires 36 billion gallons of renewable fuel by the year 2022 to be introduced into the transportation fuel mix and allows the renewable fuel to be blended into both gasoline and diesel fuel. Obligated parties will also include refiners, blenders and importers of both gasoline and diesel fuel. Unlike the RFS1 program (which only required compliance with one total renewable fuel standard until 2012, and added compliance with a cellulosic biomass standard thereafter), obligated parties must comply with the four "nested" standards. Total renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel must reach the 36 billion gallon requirement by 2022. Of the 36 billion gallons of total renewable fuels mandated by EISA, 21 billion gallons must be advanced biofuel; of the 21 billion gallons of advanced biofuel required, 16 billion gallons must be cellulosic biofuel and 1 billion gallons must be biomass-based diesel.

Figure 1 shows the volume requirements of RFS1 (red line labeled "Old RFS") compared to the volume requirements of RFS2 for the different types of renewable fuels (bar chart), as defined by EISA, from 2006 through 2022.

The provisions of EISA 2007 will expand requirements on obligated parties. Since there are four types of renewable fuels, obligated parties must obtain and demonstrate compliance with four different mandates using RINs. Second, the universe of obligated parties has been broadened to include both gasoline and diesel producers. Finally, the volumes required by the new mandate are substantially higher than those required in EPAct 2005, stretching the limits of domestic capability to produce and incorporate biofuels in the transportation fuel mix.



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Biodiesel	0	0	0	0.5	0.65	0.8	1	1	1	1	1	1	1	1	1	1	1
Any Advanced	0	0	0	0.1	0.2	0.3	0.5	0.75	1	1.5	2	2.5	3	3.5	3.5	3.5	4
Cellulosic Advanced					0.1	0.25	0.5	1	1.75	3	4.25	5.5	7	8.5	10.5	13.5	16
Any Renewable Fuels	4	4.7	9	10.5	12	12.5	13.2	13.8	14.4	15	15	15	15	15	15	15	15
Old RFS	4	4.7	5.4	6.1	6.8	7.4	7.5	7.6	7.7	7.8	7.9	8.1	8.2	8.3	8.4	8.5	8.6

Figure 1. RFS 1 and RFS 2 Volume Requirements 2006-2022

Compliance Options under the RFS1 and RFS2 Programs

The Renewable Fuel Standard programs (RFS1 and RFS2) include inherent flexibility since compliance is based on a nationwide trading program, without any per gallon requirements and without any requirement that the refiner or importer produce the renewable fuel. By purchasing RINs from other program participants that have chosen to over-comply, obligated parties will be able to fulfill their renewable fuel obligation without having to make capital investments that may otherwise be necessary in order to blend renewable fuels into gasoline or diesel fuel.

In a competitive market, RINs will be freely traded between parties at the marginal cost of production. In this case, the decision to blend as opposed to purchase credits should not disadvantage small refineries relative to other obligated parties. Based on the performance of the current market and forecasts of future market trends, we believe that sufficient RINs will be available at a price not disproportionately above the cost of production. Therefore, refiners without blending capability should pay no more than the marginal cost of production; that is, the cost of the most expensive RIN produced by blending. In this case, the absence of physical capability to blend does

not impose a disproportionate economic hardship on small refineries as compared to other obligated parties.

Review of the Current Market

The current market is generally over-supplied with RINs. This condition can be seen by examining the traded price of RINs shown in Figure 2. Over the period May – November, 2008, RIN prices averaged less than $0.05 per gallon. Such a nominal price suggests that the transaction costs of transferring RINs constitute the majority of the value of the RIN. This implies that the market views blending ethanol as economic, even without the incentive of selling the generated RIN.

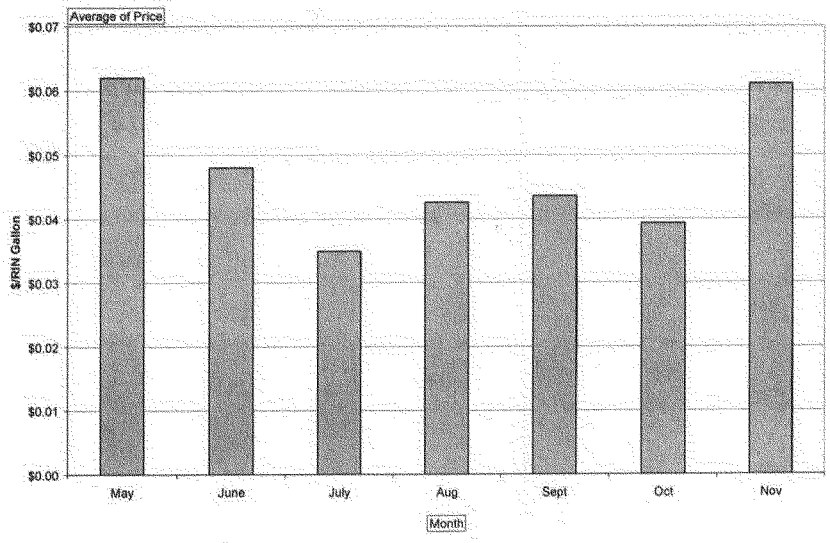


Figure 2. Average Monthly RIN Prices May - November 2008
Source: Oil Price Information Service (OPIS)

While there is no central exchange for trading RINs, various private parties facilitate the exchange of RINs. One such private party is Clean Fuels Clearinghouse, which runs the RINSTAR® Renewable Fuel Registry. As the Renewable Volume

Obligation (RVO) increases, more obligated parties are expected to purchase RINs than generate their own. As more parties become aware of the RFS2 requirements, increased trading will result. Figure 3 shows the monthly trade count from the Renewable Fuel Registry starting from the program's inception in 2007. The actual number of RIN-gallons (that is the RINs associated with a gallon of renewable fuel) is far greater than the trade count, as a single trade may entail the transfer of RINs for a batch of renewable fuel. Since the Clean Fuels Clearinghouse is a private party, it only has data on its subscribing members, which is a subset of the market. The Registry does not attempt price discovery at this time, but merely facilitates the trading among parties and reports transfers to EPA.

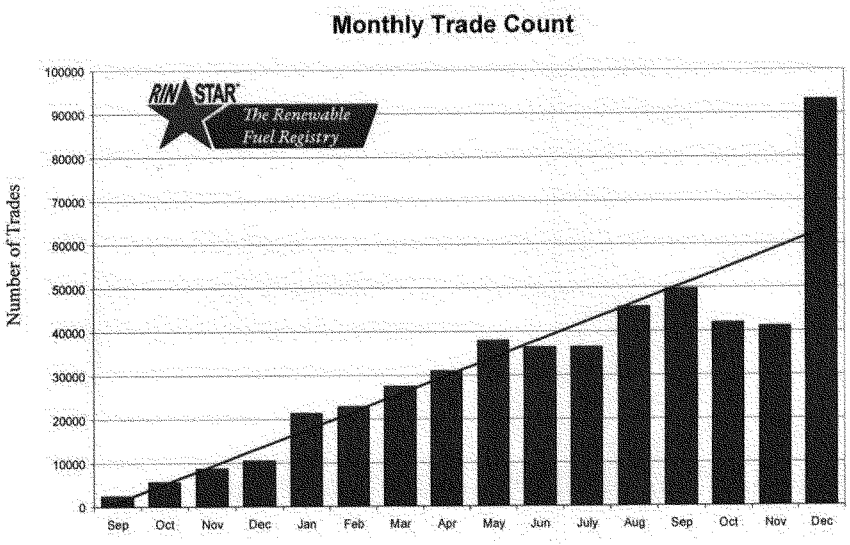


Figure 3 Monthly Trade Count in the RINSTAR® System

Future RFS Compliance Costs

Figure 4 shows a projection of the compliance cost per gallon of product, extracted from the National Energy Modeling System (NEMS) modeling run used to create the Energy Information Administration's Early Release of the Annual Energy Outlook 2009 (AEO 2009) for the period 2009 through 2022. The projected cost represents the

weighted average cost of meeting the four compliance categories in dollars per gallon of gasoline or diesel fuel, the products covered by the program. EIA projects implementation of the RFS2 program should have a minimal impact on product prices through 2013 of less than $.01 per gallon of product. Even after 2013, the EIA projections show only two years in which the RFS2 program raises product prices more than $.03 per gallon. Since the credit system will be used to transfer compliance costs to consumers, these costs may be used as a proxy to project the value of credits. DOE interprets EIA's projections to indicate that credits should be available and that credit prices will not be excessive.

RFS2 Compliance Cost per Gallon Product

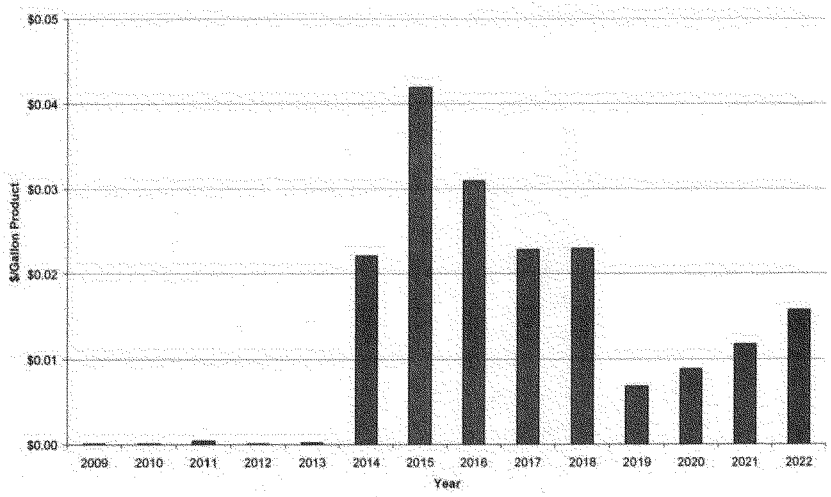


Figure 4. Annual Energy Outlook 2009 Compliance Cost Projections

Characteristics of Small Refineries

Small refineries comprise a very heterogeneous set of organizations. Some small refineries are part of large integrated corporations with both upstream and downstream activities. Others, while owning only a few or even one small refinery, are large enterprises with other lines of business. Finally, some companies have a

single small refinery providing the vast majority of the value of the enterprise. While any particular small refinery may have geographic or other capital limitations, since the obligated party is the entire company, small refineries have options available to meet their RVO other than by blending in the mandated volumes of renewable fuels. They may allow other parts of the company to over-comply, or they may purchase RINs from other obligated parties.

Table 1 lists a sample of small refineries that DOE has identified that are also owned by small companies, as defined in EPA's SUBREFA process. These refineries would be expected to have the most difficulty complying with the standard by developing facilities to blend renewable fuels into their products. The table shows the company name, location, and size of the refinery. Using EIA Form 815 data, DOE has identified those refineries that are close to terminals that currently blend ethanol. Since EIA does not track the commercial arrangements of refineries, this is a proxy of whether the refinery may actually use such a terminal to generate credits. Table 1 includes all of the refiners from the Ad Hoc RFS1 Small Refiner SUBREFA Coalition with the exception of Placid Oil. Placid has recently expanded its operable distillation capacity to 80,000 barrels per day, which may make it ineligible for the small refinery exemption if annual crude oil throughput is below 75,000 barrels per day.

Table 1. Select Small Refineries

Company Name	Site	State	Operable Capacity (BBLS/day)	Blending Capability
AGE REFINING INC	SAN ANTONIO	Texas	13000	
AMERICAN REFINING GROUP INC	BRADFORD	Pennsylvania	10000	
COUNTRYMARK COOPERATIVE INC	MOUNT VERNON	Indiana	23000	Y
FORELAND REFINING CORP	EAGLE SPRINGS	Nevada	2000	
GOODWAY REFINING LLC	ATMORE	Alabama	4100	
KERN OIL & REFINING CO	BAKERSFIELD	California	26000	Y
SAN JOAQUIN REFINING CO INC	BAKERSFIELD	California	15000	Y
SILVER EAGLE REFINING	EVANSTON	Wyoming	3000	
SILVER EAGLE REFINING	WOODS CROSS	Utah	10250	
SOMERSET REFINERY INC	SOMERSET	Kentucky	5500	
US OIL & REFINING CO	TACOMA	Washington	37850	Y
WYNNEWOOD REFINING CO	WYNNEWOOD	Oklahoma	54000	Y

Source: EIA-810 and EIA-815

Case Studies of Refineries Affected By EISA

EPAct 2005 defined an exemption for small refineries, not refiners. As illustrated in the examples described in this section, small refineries are extraordinarily diverse in size, capitalization, and role. We examine three small refineries to illustrate the various challenges small refineries might face in complying with the RFS2.

Marathon Refining, St. Paul Park, Minnesota

This 70,000 barrels per day refinery produces motor gasoline, diesel, and other products. It is part of the Marathon Oil Company, a large integrated energy company which is engaged in exploration and production of oil and oil sands, and refining, transporting, and marketing petroleum products. The refinery is located near numerous sources of ethanol in a state that has a statutory 10-percent-ethanol-blending requirement for gasoline. Marathon has over one million barrels per day refining capacity company-wide and had revenues of over $65 billion in 2007. The company has the ability to blend 1.2 billion gallons of ethanol annually, and has invested in ethanol production facilities. Therefore, the Marathon St. Paul refinery has many options to comply with its RVO. It may generate RINs through blending, or allow some other portion of the company to over-comply.

Country-Mark Cooperative, Mt. Vernon, Indiana

Country-Mark Cooperative is owned by a number of farm cooperatives. It runs a 26,500 barrels per day refinery in Mt. Vernon, Indiana. The cooperative primarily sells diesel (both on-road and off-road) and gasoline, with profits accruing to the owning cooperatives. Country-Mark owns its own pipeline and four terminals. They already blend both biodiesel and E10. Therefore, the company has the capability of generating RINs or purchasing them.

The American Refining Company Bradford, Pennsylvania

The American Refining Company owns a single refinery in Bradford, Pennsylvania. It processes approximately 10,000 barrels per day of primarily locally-produced Pennsylvania crude, producing diesel and gasoline. The company has no terminals or blending facilities, and no terminals are nearby. Therefore, this company is an example of a refinery at which it would be commercially infeasible to install blending facilities and where RINs would likely be purchased from other parties.

Record-keeping Requirements

Registration, recordkeeping, and reporting are necessary to track compliance with the RFS2 program. Since the RFS2 program contains multiple mandates, compliance will require multiple types of RINs, and will necessarily be more complex.

The compliance requirements under the RFS2 program will likely be similar to those required under the RFS1 program. Program registration for the RFS1 program uses the same basic forms that EPA uses under the reformulated gasoline (RFG) and the Mobile Source Air Toxics (MSAT) anti-dumping programs, as these forms are well known in the regulated community and are simple to fill out. Reporting under the RFS1 program currently uses a simplified method of reporting via EPA's Central Data Exchange (CDX), and records related to RIN transactions may be kept in any format. The period of record retention by reporting parties is five years, similar to other EPA fuel programs.

As described previously, commercial services exist to handle record-keeping and assignment of RINs. Therefore, costs may be scalable relative to the size or number of RINs needed. At this time, commercial services can provide record-keeping, transfer, and verification of RINs for a nominal fee, thereby reducing the need for additional staff.

Discussion of Results

Small refineries encompass a broad category of businesses. Small refineries may be parts of large integrated petroleum companies with numerous refineries, a single or small group of refineries within a large diversified corporation, or a stand-alone organization with a single processing plant. Furthermore, as the actual generation of RINs occurs, the RFS2 program will have a different impact depending upon the corporate structure. Small refineries without access to blending capability may have to enter the RIN market. For stand-alone small refineries, transaction costs may create a significant burden, although third-party services are already available to ease this burden. For small refineries that are subsidiaries of larger companies, this is less of an issue. Finally, for small refineries that are part of integrated major or supermajor energy companies, RINs may be obtained internally or in the open market, and there is no reason to expect that they would be disproportionately harmed by inclusion as obligated parties in the RFS2 program.

Conclusion

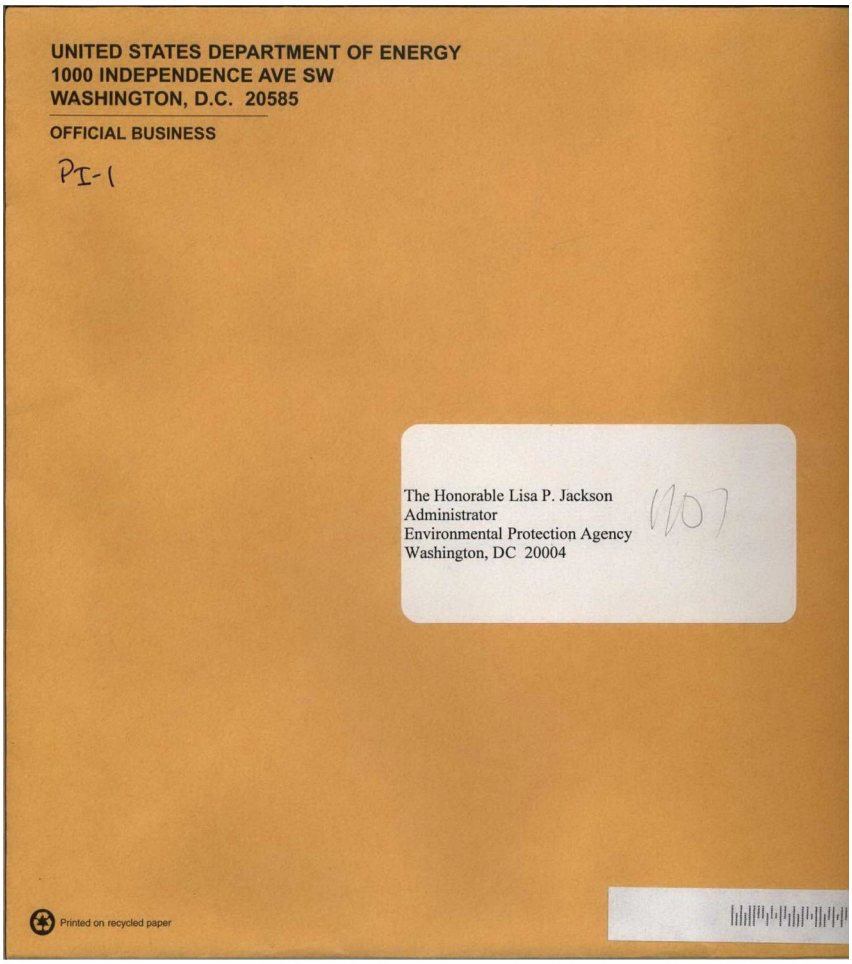
Small refineries comprise a heterogeneous group of facilities. Some will be able to generate RINs through blending renewable fuels into their products; others may choose to purchase RINs from refiners with RINs in excess of their RVOs. Currently there appears to be no shortage of RINs available under RFS1. The RFS2 legislation has provided flexibility to ensure that the RFS2 RVO requirements will not exceed the renewable fuels industries' capabilities to produce renewable fuels and also provides alternative RINs if the RVO volumes are not economically viable. Markets are developing for the exchange and tracking of RINs. It is too early to project whether these markets will continue to be liquid and competitive; as long as these markets continue to the liquid and competitive, there is no reason to believe small refineries will be disproportionately harmed by inclusion in the RFS2 program. Therefore, DOE has not determined that any small refinery would be subject to disproportionate economic hardship under the RFS2 program and thus has determined that the exemption should not be extended beyond 2010. However, should

circumstances change and the RIN markets become non-competitive or illiquid, individual refineries still have a statutory right to petition EPA for an extension of the small refinery exemption.

Appendix A. List of Small Refineries and Operable Capacity in BBLS/day

Source: EIA form EI-810

COMPANY_NAME	SITE	STATE_NAME	OPERABLE CAPACITY
AGE REFINING INC	SAN ANTONIO	Texas	13000
ALON USA ENERGY INC	BIG SPRING	Texas	67000
AMERICAN REFINING GROUP INC	BRADFORD	Pennsylvania	10000
BIG WEST OF CALIFORNIA	BAKERSFIELD	California	66000
BIG WEST OIL CO	NORTH SALT LAKE	Utah	29400
CALCASIEU REFINING CO	LAKE CHARLES	Louisiana	78000
CALUMET LUBRICANTS CO LP	COTTON VALLEY	Louisiana	13020
CALUMET LUBRICANTS CO LP	PRINCETON	Louisiana	8300
CALUMET SHREVEPORT LLC	SHREVEPORT	Louisiana	42000
CENEX HARVEST STATES COOP	LAUREL	Montana	55000
CHEVRON USA INC	HONOLULU	Hawaii	54000
CHEVRON USA INC	SALT LAKE CITY	Utah	45000
CITGO ASPHALT REFINING CO	PAULSBORO	New Jersey	32000
CITGO ASPHALT REFINING CO	SAVANNAH	Georgia	28000
CONOCOPHILLIPS COMPANY	BILLINGS	Montana	58000
CONOCOPHILLIPS COMPANY	RODEO	California	76000
COUNTRYMARK COOPERATIVE INC	MOUNT VERNON	Indiana	23000
CROSS OIL REFINING & MARKETING INC	SMACKOVER	Arkansas	7200
DELEK REFINING LTD	TYLER	Texas	58000
ERGON REFINING INC	VICKSBURG	Mississippi	23000
ERGON WEST VIRGINIA INC	NEWELL (CONGO)	West Virginia	20000
EXXONMOBIL REFINING & SUPPLY CO	BILLINGS	Montana	60000
FORELAND REFINING CORP	EAGLE SPRINGS	Nevada	2000
FRONTIER REFINING INC	CHEYENNE	Wyoming	47000
GIANT INDUSTRIES INC	BLOOMFIELD	New Mexico	16800
GIANT REFINING CO	GALLUP	New Mexico	20800
GIANT YORKTOWN REFINING	YORKTOWN	Virginia	59375
GOODWAY REFINING LLC	ATMORE	Alabama	4100
GULF ATLANTIC OPERATIONS LLC	MOBILE	Alabama	16700
HOLLY CORP REFINING & MARKETING	WOODS CROSS	Utah	24700
HUNT REFINING CO	TUSCALOOSA	Alabama	34500
HUNT SOUTHLAND REFINING CO	SANDERSVILLE	Mississippi	11000
KERN OIL & REFINING CO	BAKERSFIELD	California	26000
LION OIL CO	EL DORADO	Arkansas	70000
LITTLE AMERICA REFINING CO	EVANSVILLE (CASPER)	Wyoming	24500
MARATHON PETROLEUM CO LLC	CANTON	Ohio	73000
MARATHON PETROLEUM CO LLC	SAINT PAUL PARK	Minnesota	70000
MARATHON PETROLEUM CO LLC	TEXAS CITY	Texas	72000
MONTANA REFINING CO	GREAT FALLS	Montana	9500
MURPHY OIL USA INC	SUPERIOR	Wisconsin	34300
PARAMOUNT PETROLEUM CORPORATION	PARAMOUNT	California	50000
PLACID REFINING CO	PORT ALLEN	Louisiana	56000
SAN JOAQUIN REFINING CO INC	BAKERSFIELD	California	15000
SHELL CHEM LP	SAINT ROSE	Louisiana	55000
SHELL CHEM YABUCOA INC	YABUCOA	Puerto Rico	77900
SILVER EAGLE REFINING	EVANSTON	Wyoming	3000
SILVER EAGLE REFINING	WOODS CROSS	Utah	10250
SINCLAIR OIL CORP	SINCLAIR	Wyoming	66000
SINCLAIR OIL CORP	TULSA	Oklahoma	70300
SOMERSET REFINERY INC	SOMERSET	Kentucky	5500
SUNCOR ENERGY (USA) INC	COMMERCE CITY	Colorado	62000
SUNCOR ENERGY (USA) INC	DENVER	Colorado	32000
Tesoro West Coast	MANDAN	North Dakota	58000
Tesoro West Coast	SALT LAKE CITY	Utah	58000
VENTURA REFINING & TRANS LLC	CUSTER	Oklahoma	12000
UNITED REFINING CO	WARREN	Pennsylvania	65000
US OIL & REFINING CO	TACOMA	Washington	37850
WYNNEWOOD REFINING CO	WYNNEWOOD	Oklahoma	54000
WYOMING REFINING CO	NEWCASTLE	Wyoming	14000



UNITED STATES DEPARTMENT OF ENERGY
1000 INDEPENDENCE AVE SW
WASHINGTON, D.C. 20585

OFFICIAL BUSINESS

PI-1

The Honorable Lisa P. Jackson
Administrator
Environmental Protection Agency
Washington, DC 20004

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111TH CONGRESS, *1st Session* | SENATE | REPORT 111–45

ENERGY AND WATER DEVELOPMENT APPROPRIATIONS BILL, 2010

JULY 9, 2009.—Ordered to be printed

Mr. DORGAN, from the Committee on Appropriations, submitted the following

REPORT

[To accompany S. 1436]

The Committee on Appropriations reports the bill (S. 1436) making appropriations for energy and water development and related agencies for the fiscal year ending September 30, 2010, and for other purposes, favorably thereon and recommends that the bill do pass.

The Committee on Appropriations, to which was referred the bill (H.R. 0000) making appropriations for energy and water development and related agencies for the fiscal year ending September 30, 2010, and for other purposes, reports the same to the Senate with an amendment, and an amendment to the title, and recommends that the bill as amended do pass.

Amount in new budget (obligational) authority, fiscal year 2010

Total of bill as reported to the Senate	$34,271,000,000
Amount of 2009 appropriations	92,533,165,000
Amount of 2010 budget estimate	34,914,709,000
Bill as recommended to Senate compared to—	
2009 appropriations	−58,262,165,000
2010 budget estimate	−643,709,000

50–870 PDF

DEPARTMENTAL ADMINISTRATION

(GROSS)

Appropriations, 2009	$272,643,000
Budget estimate, 2010	302,071,000
Committee recommendation	293,684,000

(MISCELLANEOUS REVENUES)

Appropriations, 2009	−$117,317,000
Budget estimate, 2010	−119,740,000
Committee recommendation	−119,740,000

NET APPROPRIATION

Appropriations, 2009	$155,326,000
Budget estimate, 2010	182,331,000
Committee recommendation	−173,944,000

The Committee recommends $293,684,000 for Departmental Administration, which provides a net appropriation of $173,944,000 in fiscal year 2010. The Departmental Administration account supports 10 Department-wide management organizations including administrative, human resources, financial, workforce diversity, congressional liaison, and program management functions.

The January 2009 Small Refineries Exemption Study issued by the Department of Energy was intended to determine whether small refineries faced a disproportionate economic hardship in meeting Renewable Fuel Standard [RFS] requirements beginning in 2011. The Committee understands the study contained inadequate small refinery input, did not assess the economic condition of the small refining sector, take into account regional factors or accurately project RFS compliance costs. Therefore, the Committee does not believe the study is complete, nor is the Department able to make the required determination at this time. In view of these deficiencies and the importance of the study, the Department is directed to reopen and reassess the Small Refineries Exemption Study by June 30, 2010. The Department is specifically directed to seek and invite comment from small refineries on the RFS exemption hardship question, assess RFS compliance impacts on small refinery utilization rates and profitability, evaluate the financial health and ability of small refineries to meet RFS requirements, study small refinery impacts and regional dynamics by PADD, and reassess the accuracy of small refinery compliance costs through the purchase of renewable fuel credits. Finally, the Committee notes that the 2009 study does not estimate the price of tradable fuel credits, but the Committee is aware that from 2008 to 2009, price has increased nearly threefold. The Committee expects the Department to undertake an economic review to estimate the actual economic impact of the RFS on small refineries on a regional basis.

OFFICE OF THE INSPECTOR GENERAL

Appropriations, 2009	[1] $66,927,000
Budget estimate, 2010	51,445,000
Committee recommendation	51,927,000

[1] Includes emergency appropriations of $15,000,000 under Public Law 111–5.

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

MEMORANDUM

SUBJECT: Decision on 2018 Small Refinery Exemption Petitions

OFFICE OF
AIR AND RADIATION

FROM: Anne Idsal, Acting Assistant Administrator
Office of Air and Radiation

TO: Sarah Dunham, Director
Office of Transportation and Air Quality

Section 211(*o*)(9)(B) of the Clean Air Act (CAA or the Act) authorizes the Administrator to temporarily exempt small refineries from their renewable fuel volume obligations under the RFS program "for the reason of disproportionate economic hardship" (DEH). The Act instructs EPA, in consultation with the Department of Energy (DOE), to consider the DOE Small Refinery Study[1] and "other economic factors" in evaluating small refinery exemption (SRE) petitions. The statute does not define "disproportionate economic hardship," leaving for EPA's discretion how it implements this exemption provision.[2]

As part of EPA's process for evaluating SRE petitions, EPA asks DOE to evaluate all the information EPA receives from each petitioner. DOE's expertise in evaluating economic conditions at U.S. refineries is fundamental to the process both DOE and EPA use to identify whether DEH exists for petitioning small refineries in the context of the RFS program. After evaluating the information submitted by the petitioner, DOE provides a recommendation to EPA on whether a small refinery merits an exemption from its RFS obligations. As described in the DOE Small Refinery Study, DOE assesses the potential for DEH at a small refinery based on two sets of metrics. One set of metrics assesses structural and economic conditions that could disproportionately impact the refinery (collectively described as "disproportionate impacts" when referencing Section 1 and Section 2 of DOE's scoring matrix). The other set of metrics assesses the financial conditions that could cause viability concerns at the refinery (described as "viability impairment" when referencing Section 3 of DOE's scoring matrix). DOE's recommendation informs EPA's decision about whether to grant or deny an SRE petition for a small refinery.

Previously, DOE and EPA considered that DEH exists only when a small refinery experiences *both* disproportionate impacts *and* viability impairment. In response to concerns that the two agencies' threshold for establishing DEH was too stringent, Congress clarified to DOE that DEH can exist if DOE finds that a small refinery is experiencing *either* disproportionate impacts *or* viability impairment. If so, Congress directed DOE to recommend a 50 percent exemption from the RFS. This was relayed in language included in an explanatory statement accompanying the

[1] "Small Refinery Exemption Study, An Investigation into Disproportionate Economic Hardship," Office of Policy and International Affairs, U.S. Department of Energy, March 2011 (DOE Small Refinery Study).
[2] *Hermes v. Consol., LLC v. EPA*, 787 F.3d 568, 575 (D.C. Cir. 2015).

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2016 Appropriations Act that stated: "If the Secretary finds that either of these two components exists, the Secretary is directed to recommend to the EPA Administrator a 50 percent waiver of RFS requirements for the petitioner."[3] Congress subsequently directed EPA to follow DOE's recommendation, and to report to Congress if it did not.[4]

Based on DOE's recommendations for the 2018 petitions, I am today granting full exemptions for those 2018 small refinery petitions where DOE recommended 100 percent relief because these refineries will face a DEH. I am denying exemptions for those 2018 small refinery petitions where DOE recommended no relief because they will not face a DEH.

I am also granting full exemptions for those 2018 small refinery petitions where DOE recommended 50 percent relief. This decision is appropriate under the Act and is consistent with the case law recognizing EPA's independent authority in deciding whether to grant or deny RFS small refinery petitions.[5] DOE's recommendations recognize an economic impact on these small refineries, and I conclude these small refineries will face a DEH meriting relief. I have concluded that the best interpretation of Section 211(*o*)(9)(B) is that EPA shall either grant or deny petitions for small refinery hardship relief in full, and not grant partial relief. The exemption available under Section 211(*o*)(9)(B) is explicitly described as an "extension of the exemption under subparagraph (A)." In turn, subparagraph (A) provides that the requirements of the RFS program "shall not apply to small refineries until calendar year 2011." It is evident that the original exemption under subparagraph (A) was a full exemption, and therefore I conclude that when Congress authorized the Administrator to provide an "extension" of that exemption for the reason of DEH, Congress intended that extension to be a full, and not partial, exemption. This approach is also consistent with congressional direction since enactment of the provision, which states: "The Agency is reminded that, regardless of the Department of Energy's recommendation, additional relief may be granted if the Agency believes it is warranted."[6]

Dated: 7/8/2019

Anne Idsal
Acting Assistant Administrator
Office of Air and Radiation

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[3] Consolidated Appropriations Act, 2016, Pub. L. No. 114-113 (2015). The Explanatory Statement is available at: https://rules.house.gov/bill/114/hr-2029-sa.

[4] Senate Report 114-281 ("When making decisions about small refinery exemptions under the RFS program, the Agency is directed to follow DOE's recommendations which are to be based on the original 2011 Small Refinery Exemption Study prepared for Congress and the conference report to division D of the Consolidated Appropriations Act of 2016. Should the Administrator disagree with a waiver recommendation from the Secretary of Energy, either to approve or deny, the Agency shall provide a report to the Committee on Appropriations and to the Secretary of Energy that explains the Agency position. Such report shall be provided 10 days prior to issuing a decision on a waiver petition.").

[5] *Sinclair Wyoming Refining Co. v. EPA*, 874 F.3d 1159, 1166 (10th Cir. 2017); *See also Hermes Consol.* 787 F.3d at 574-575; *Lion Oil Co. v. EPA*, 792 F.3d 978, 982-983 (8th Cir. 2015).

[6] Consolidated Appropriations Act, 2019, Pub. L. No. 116-6 (2019), *see* H.Rept. 116-9 at 741 (February 13, 2019).

Contains Material Claimed as Confidential Business Information

[redacted] Request for Extension of Small Refinery Temporary Exemption Under the Renewable Fuel Standard Program For [redacted]

Contains Information Claimed by [redacted] To be Confidential Business Information

Office of Transportation and Air Quality

Contains Material Claimed as Confidential Business Information

[redacted]

Section 211(o)(9) of the Clean Air Act (CAA) authorizes the Administrator to temporarily exempt small refineries from their renewable fuel volume obligations under the RFS program on the basis of a finding of "disproportionate economic hardship" (DEH). The statute directs EPA, in consultation with the Department of Energy (DOE), to consider the (DOE) Small Refinery Study and "other economic factors" in evaluating small refinery exemption petitions, but CAA section 211(o)(9) leaves the definition of DEH to the Administrator's discretion for purposes of implementing this exemption provision.

After evaluating information submitted by the petitioner, DOE provides a recommendation to EPA on whether a refinery merits exemption from the RFS. As described in its study, DOE assesses the potential for DEH at a refinery on the basis of two sets of metrics. One set assesses structural and economic conditions that could disproportionately impact the refinery (described as "disproportionate impacts" for purposes of DOE's scoring metrics, and also described as "structural" factors or conditions here). The other set assesses economic factors that could cause viability concerns (described as "viability" for purposes of DOE's scoring metrics, and also described as "economic" factors or conditions here).

In previous year decisions, DOE and EPA considered that DEH exists only when a refinery experiences both disproportionate impacts and viability impairment. In response to concerns that the two agencies' threshold for establishing DEH was too stringent, Congress clarified to DOE that DEH can exist if DOE finds that a small refinery is experiencing *either* disproportionate impacts *or* viability impairment. If so, Congress directed DOE to recommend a 50 percent exemption from the RFS. This was relayed in language included in an explanatory statement accompanying the 2016 Appropriations Act that stated: "If the Secretary finds that either of these two components exists, the Secretary is directed to recommend to the EPA Administrator a 50 percent waiver of RFS requirements for the petitioner."[1] Congress then directed EPA to follow DOE's recommendation.[2] [redacted]

For the purposes of implementing CAA section 211(o)(9) for 2017 small refinery exemption decisions, EPA has determined that DEH can exist on the basis of adverse structural conditions alone. A difficult year may exacerbate economic problems for small refineries that

[1] Consolidated Appropriations Act, 2016, Pub. L. No. 114-113 (2015). The Explanatory Statement is available at: https://rules.house.gov/bill/114/hr-2029-sa.

[2] Consolidated Appropriations Act, 2017, Pub. L. No. 115-31 (2017); *See also* Senate Report 114-281 ("When making decisions about small refinery exemptions under the RFS program, the Agency is directed to follow DOE's recommendations which are to be based on the original 2011 Small Refinery Exemption Study prepared for Congress and the conference report to division D of the Consolidated Appropriations Act of 2016.").

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF COLUMBIA

Cross Oil Refining & Marketing, Inc.,	)	Civil Action
	)	No. 21-cv-1825
Plaintiff,	)	
	)	STATUS CONFERENCE
vs.	)	
	)	Washington, DC
Michael S. Regan,	)	January 20, 2022
	)	Time: 10:00 a.m.
Defendant.	)	

TRANSCRIPT OF STATUS CONFERENCE
HELD BEFORE
THE HONORABLE JUDGE JIA M. COBB
UNITED STATES DISTRICT JUDGE

A P P E A R A N C E S

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Official Court Reporter
United States Courthouse, Room 6523
333 Constitution Avenue, NW
Washington, DC 20001
202-354-3267

THE COURTROOM DEPUTY: Good morning, Your Honor. We have everyone present.

Your Honor, we are present in civil action 21-1825, *Cross Oil Refining and Marketing, Inc., versus Michael S. Regan*.

Starting with plaintiff's counsel, please state your appearance for the record, introduce any co-counsel that is with you.

MR. DeLAQUIL: Thank you. This is Mark DeLaquil from the Baker and Hostetler law firm on behalf of the plaintiff Cross Oil Refining and Marketing. And with me is my colleague, Cory Barnes

THE COURT: Good morning.

MR. BARNES: Good morning.

THE COURT: Ms. Franklin, please --

THE COURTROOM DEPUTY: Defense counsel, please state your appearance for the record.

MS. IZFAR: I apologize. This is Sarah Izfar, with the United States Department of Justice, on behalf of Michael Regan, Administrator of the U.S. Environmental Protection Agency.

THE COURT: Could you repeat your last name again?

MS. IZFAR: Izfar, I-Z-F-A-R.

THE COURT: Okay. Izfar. Thank you.

We're here this morning because I received the

parties' last joint status report and I wanted to talk a little bit about the posture of the case. And I understand that the case is currently stayed, that the defendant would like the stay to remain in place and the plaintiff would like for the stay to be lifted.

So, I've read the status report, I've read your respective positions. And I would like to start with you, Ms. Izfar, if you could first educate me a little bit about the notice and comment process for a proposed decision. So, I understand this is not a rulemaking, but it's a proposed decision. So if you could tell me, kind of, is it the standard notice and comment process that is used for rulemaking, and what is the timeline? Where is defendant, the EPA, in the process of rulemaking -- of notice and comment with respect to the proposed decision at issue?

MS. IZFAR: Yes. Thank you, Judge Cobb. So this is a -- it is a proposed denial of more than 60 petitions, including Cross' petition -- Cross Oil's petition. And on December 7th, 2021 EPA proposed to deny that. And the comment period closes on February 7. So while you're correct that it's not a rulemaking, EPA has invited everyone affected to -- all stakeholders to submit comment on the proposed denial of its period.

So that period will close on February 7th and then EPA will review the comments and finalize its decision and

issue a final decision. I don't have information as to when that will happen. I only know that the comment period will close on February 7th, which is why we have proposed 90-day status reports, to ensure that there's no undue delay.

THE COURT: Okay. And then I know you just said that you can't make a representation about when any final decision will issue, but in your experience, or agency experience, I know -- and that's probably not a fair question, but, you know, I just want to get a sense of, you know, what are you anticipating? Understanding I'm not going to hold you to this, but are we talking months? Are we talking a year? Could this be more than a year? I mean, what are we talking about here?

MS. IZFAR: I don't expect this to be a year or more than a year, because I know that this action is part of a suite of actions that EPA has taken and intends to take over the next few months to get this program, the RFS program, back on track. There have been a number of delays and this program has been subject to a lot of litigation, which we, you know, outlined in our status report, in the Tenth Circuit and also in the Supreme Court. And so EPA is trying to develop a coordinated approach.

So, along with this proposed denial, there are also proposed extensions of compliance deadlines. So, you know, all of the small refineries have to comply with certain standards, and my understanding is that EPA has proposed to extend the 2019 standard that would affect Cross Oil, and they intend to

finalize that extension by the end of -- I believe it's the end of February. But, like I said, I don't -- I'm not positive about that. There's -- there are also other rulemaking -- or, not rulemakings, but other decisions that they need to issue as well relating to setting the volume of the fuels and all of that. So I understand that this action is part of that coordinated suite of actions.

THE COURT: And the other 60-plus refineries or so that are impacted by this proposed decision, or proposed denial, have any of those other refineries filed litigation? Are you in active litigation with any of those refineries?

MS. IZFAR: I believe a handful of them have. I believe the vast majority have not filed litigation, but that a handful have filed similar cases to this. I am personally not assigned to any of them, so I can't speak with definition. Plaintiff's counsel might actually have more information on that. But, I do think that there are a handful of cases that have also filed similar actions, alleging that EPA has failed to take a nondiscretionary duty to deny the petition.

THE COURT: Okay. So you don't know anything about the status even generally, meaning are those cases stayed? Are they proceeding in litigation? Or you just don't know anything to make a representation?

MS. IZFAR: I can get that information for you, and I'm happy to provide a supplemental filing. I do believe that

one of them is stayed. And Mr. -- like I said, I think Mr. DeLaquil may be coordinating with some of the other refineries and may have better information. But I'm happy to provide a supplemental finding with accurate information. I just don't have information about the other cases right now.

THE COURT: Sure.

MR. DeLAQUIL: Your Honor, this is --

MS. IZFAR: I'm sorry. I just want to correct the record. There was one case that Mr. DeLaquil brought that I was responsible for, that is *United Refining*, and that was a case that we settled and that was mentioned in the status report. And we did issue the stand-alone decision on that one. But as for the other ones, I'm not sure.

THE COURT: I know about that one. Mr. DeLaquil, I'm familiar with *United Refining Company* because you brought it to my attention in the filing. Just generally, do you know if any other of these refineries have filed litigation and if any of those matters are in active litigation and not stayed?

MR. DeLAQUIL: I do know, Your Honor, that Delek, the company Delek, has filed a deadline suit in the D.C. District Court on behalf of one or more refineries. My understanding is that they have a report due in that case on February 1st. I'm not sure whether or not the Department of Justice has answered in that case, but I do know that case is extended, with a report due February 1st.

THE COURT: Okay. Thank you. That's helpful.

Ms. Izfar, can you just articulate a little bit to me what your prejudice is? I'm just going to tell you what my inclination is. So, where there are -- where there is a joint request for a stay -- if this were a joint request, I would grant it, no problem. But here, I have a situation where, you know, plaintiff has filed suit, wants the case to proceed. I understand efficiency concerns and conservation of resources concerns, but in terms of exercising my discretion and kind of making sure that plaintiffs who file suit can have their cases resolved, you know, expeditiously, I'm not really understanding, particularly given that you've made -- EPA has made a stand-alone decision in at least one other case in this District, what the prejudice is to proceeding with the litigation here, answering the complaint and moving forward. Particularly given, and understandably, you don't know when this process will be final. And this case was filed before, you know, the proposed decision, is my understanding. If you could just articulate your prejudice. And I just want to be very clear about where I'm leaning, just given that there's a -- not a joint request for a stay here.

MS. IZFAR: Understood, Your Honor. And I appreciate the opportunity. I think that the major prejudice that EPA would suffer is that if it were required to decide the petition ahead of the finalization of this proposed denial, then EPA

wouldn't necessarily have the opportunity to take into account all of the comments that it has received from that administrative process and, also, EPA has a strong interest in pursuing a coordinated response.

I understand that EPA did issue a stand-alone petition in *United* and Mr. DeLaquil is challenging that decision in the Third Circuit -- or, I should say United Refining is challenging that decision in the Third Circuit. And it's in EPA's interest to ensure that its decision is one that's coordinated, so that if there is a potential challenge, that those challenges can also be coordinated.

And I will also say that I think that decision -- it was EPA's preference to also include that decision as part of, you know, the mass decision, but because of the deadlines due, EPA had to issue that stand-alone decision and -- and so I don't think the *United Refining* decision is the best example of how EPA can simply issue a stand-alone decision and not suffer any prejudice. I would argue that there was some prejudice that EPA suffered. But more importantly, I don't think there's any prejudice on the part of the refineries, given that EPA is also extending -- you know, proposing to extend the compliance deadline.

So this isn't a situation in which, you know, the refinery will have to comply without knowing its status, you know, the status of its petition. The refinery will know the

status of its petition before it's required to comply with the standard. So, I think this is a classic case in which allowing the administrative process to run its course, you know, doesn't prejudice the plaintiff and preserves, you know, the court's and the parties' resources.

And if you don't mind, I will just add one additional point, which is that if, for example, we do go to merit briefing and we do brief, you know, the appropriate merit remedy, we may end up in the exact same place we are now, which is that, you know, EPA will propose a schedule to decide the petition. And, so, that is why we ask to continue this -- to continue this stay, to ensure accountability, with 90-day status reports, with the understanding that the Court can, in its discretion, lift the stay at a later date.

THE COURT: Okay. Thank you. Mr. DeLaquil, I would ask you to articulate your prejudice, given the representation about extending the compliance deadline and the representation that the plaintiff is not prejudiced by a continued stay. What's your response to that?

MR. DeLAQUIL: With all due respect to my colleague at the Department of Justice, these hardship exemptions are applied for by small refineries because they are already suffering prejudice by having to comply with the RFS program. A refinery can be in any one of two positions at this stage. It can either be long on RINs, which means it has the credits

to comply with the Renewable Fuels Standard program, in which case it has paid a substantial amount of money that it cannot use for other economic purposes and tied up in RINs that may not be necessary, or it's short on RINs, in which case it's holding a reserve on its books that limits its financial ability going forward.

And so there's an ongoing financial impairment to any refinery that's subject to an overdue hardship waiver. And, so, that is an ongoing financial impairment of the company that is -- that is a harm in the interim. And I would note a couple of other things: While I'm certain that EPA would like to issue its decision this year in that proposed decision denial, EPA is already 17 months overdue on Cross Oil's petition and it's missed a number of other deadlines under this statute, the Renewable Fuel Standards program, over the years, including fundamental obligations, by extending renewable fuel volumes for the 2021 year, and we're already in 2022.

And so we're concerned that without a judicial deadline, this could go on for years. I don't think that three-month status reports do much to ensure accountability. I've got another case where we've been submitting three-month status reports for ten years; it becomes a recurring Outlook reminder.

And so in light of the ongoing financial harm to Cross, which exists in the absence of a decision, we would ask

this Court to have EPA answer the complaint and move to briefing on the merits. In this case I don't think there really is a dispute on the merits, there's no dispute that EPA is overdue.

THE COURT: Okay. Ms. Izfar -- am I pronouncing your last name correctly?

MS. IZFAR: It's Izfar.

THE COURT: Izfar. I'll let you respond to that, to Mr. DeLaquil's comments and argument about the prejudice suffered and the timing, if you have anything more to add that you haven't said already.

MS. IZFAR: The only point I would make is that I believe that the prejudice that Mr. DeLaquil articulated goes to the participation in the program, and that's not necessarily prejudice suffered from a delay in a decision on the petition. As we all know, EPA has proposed to deny the petition and, so, regardless -- so if, for example, you know, a decision was accelerated and EPA were forced to finalize that decision ahead of its preferred schedule, that prejudice, the hardship that he has articulated would remain because that goes to the participation in the program and his disagreement as to EPA's assessment that his client suffers some sort of disproportionate economic harm. So that's really not at issue in this case.

MR. DeLAQUIL: Your Honor, if I could please --

THE COURT: Sure.

MR. DeLAQUIL: If I could please respond briefly on that? Because I think this is an important point.

THE COURT: Sure.

MR. DeLAQUIL: The purpose of Section 304 of the Clean Air Act, which allows us to bring this lawsuit, is to ensure that private parties have a remedy when the agency decides it would like to administer one of its statutory programs in a manner other than Congress intended. In this case Congress directed EPA to decide small refining petitions within three months. Not to hold them and decide them all at the same time, but to decide them shortly after they're submitted in respect to the respective economic hardship suffered by each refinery.

In a way, EPA's decision to default in its statutory obligation in over 60 cases reminds me of the basketball coach that famously said he wanted his players to foul on every single play because the refs don't want to shut the game down, and so eventually they will stop calling the fouls. The situation we face here, with there being dozens and dozens of overdue petitions, is entirely a situation of EPA's own making and Cross should not be held and put in a worse position because EPA has defaulted wholesale on these petitions.

THE COURT: Thank you both for your arguments, They've been very helpful.

Ms. Izfar, I certainly understand your position, but my inclination going into this hearing, having thoroughly considered the arguments in the joint status report, was to lift the stay in the case. And so that's going to be my ruling. I think a lot of the prejudice that you articulated seems to be just a normal prejudice inherent in the work of litigation. And, so, I don't know that I would feel differently if there was a, you know, a set deadline in which this proposed decision would take effect.

But, certainly, that indefinite -- and we're really talking about an indefinite stay with a proposal to do status reports every three months -- that certainly, to me, weighs in favor of lifting it and allowing the case to proceed. Again, if this were a joint request there would be no issue. But where plaintiff has filed a suit and wants to have resolution of the claim that the plaintiff has filed, and where it's in my discretion to do so, I think that the stay should be lifted at this point.

So that's my ruling with respect to the stay. I also ask the parties, you know, to be prepared to discuss, if the Court should lift the stay, which I have, what the schedule for future proceedings would look like. I don't know if you've had the opportunity to confer with each other about that. I understand the first order of business, there needs to be an answer filed, so we can talk about a deadline for that. And we

can talk about a proposed schedule now or set a date by which the parties can confer and propose something in writing to file on ECF that I can consider.

Let me start with you, Mr. DeLaquil. What is your preference? Have you talked to Ms. Izfar about a proposed schedule in this matter?

MR. DeLAQUIL: Your Honor, Ms. Izfar and I, you know, have work productively in these cases before and we have conferred on a schedule. And we've arrived at a joint schedule that, you know, we believe would fairly -- fairly balance the parties' interests. And that schedule is that EPA would file an answer 21 days after your decision lifting the stay. The plaintiff would file a motion for summary judgment 21 days after EPA files its answer, and that EPA would file an opposition brief 30 days after the plaintiff's motion for summary judgment.

THE COURT: Okay. That's fine. Ms. Izfar, is that consistent with your recollection and current position about an appropriate schedule?

MS. IZFAR: It is, Your Honor, but I -- I'm looking at my schedule right now, and if we're lifting it -- given Your Honor's decision to lift the stay today, three weeks from now I'm supposed to be traveling for an oral argument. So I only ask that we -- you know, for maybe another week, and to have the answer due on February 17th, as opposed to the 10th, if

Mr. DeLaquil would not oppose that.

MR. DeLAQUIL: We would certainly not oppose that, as a professional courtesy with Ms. Izfar.

MS. IZFAR: Thank you.

THE COURT: So defendant's answer would be due on February 17th. And, Ms. Izfar, then would the 21 and 30 days follow from that deadline? So summary judgment motion due 21 days after the 17th, opposition due 30 days after summary judgment motion filed?

MS. IZFAR: Yes. Yes, Your Honor.

THE COURT: Okay. That's great. That's not a problem. And then I will ask, just because I notice from the docket that the reason that this case was initially stayed was because there were settlement negotiations that the parties wanted to conduct, it looks like in the other matter settlement negotiations proved fruitful. You know, I don't want to meddle or micromanage your settlement negotiations, but was wondering if there's any assistance through mediation or any assistance you need from the Court that you think would be helpful in resolving this? Or, you know, is the best course to just proceed with the schedule that you've just proposed and if there is a resolution down the line, I guess you can let me know.

Mr. DeLaquil, what is your responsive position in terms of the likelihood of a settlement in this matter?

MR. DeLAQUIL: I think that the parties' reference to a settlement earlier in this case had to do with our belief at the time that EPA may be actually issuing decisions on these petitions in 2021. And so while I -- I don't want to tell you that Ms. Izfar and I couldn't reach a settlement. And if there's a deadline by which EPA proposes to issue Cross's decision, I would be happy to discuss it with Mrs. Izfar. As I mentioned earlier, we've worked productively in other cases. And if there's a settlement to be reached, I expect that we could reach it under the current schedule.

THE COURT: Okay. Ms. Izfar, do you agree with that?

MS. IZFAR: Yes, I agree. To the extent EPA would be in a position to settle, I think I could reach a settlement with Mr. DeLaquil independent of mediation.

THE COURT: Okay. So, you know, if you do successfully resolve the case and agree upon a deadline, or otherwise resolve it, just let us know as soon as possible. But otherwise, at some point today we will be issuing both a minute order that acknowledges that the stay has been lifted in the case, and also a minute order setting forth the briefing schedule both for responding to the complaint and for briefing the motion for summary judgment.

Mr. DeLaquil, from plaintiff's perspective, is there anything else that we should discuss before concluding this hearing?

MR. DeLAQUIL: There's nothing else we should discuss, but there's one statement Ms. Izfar made where the parties have a difference of position, and that's whether the notice that the EPA published in the *Federal Register* constitutes a rule or not. And I think -- we disagree on that, I want to state it for the record. But there's nothing else that I ask -- that I'm asking of the Court at this time.

THE COURT: Okay. And, Ms. Izfar, on behalf of the EPA, is there anything else that you want to raise or discuss before we conclude the hearing?

MS. IZFAR: No, Your Honor. Thank you.

THE COURT: Okay. Thank you both. Have a great day. And we will get this order issued at some point today.

MS. IZFAR: Thank you.

MR. DeLAQUIL: Thank you, Your Honor.

MS. IZFAR: Thank you. Bye-bye.

* * *

CERTIFICATE OF OFFICIAL COURT REPORTER

I, JANICE DICKMAN, do hereby certify that the above and foregoing constitutes a true and accurate transcript of my stenographic notes and is a full, true and complete transcript of the proceedings to the best of my ability.

Dated this 4th day of February, 2022

_____

Janice E. Dickman, CRR, CMR, CCR
Official Court Reporter
Room 6523
333 Constitution Avenue, N.W.
Washington, D.C. 20001

United States Senate
COMMITTEE ON ENVIRONMENT AND PUBLIC WORKS
WASHINGTON, DC 20510–6175

January 30, 2020

The Honorable Gene L. Dodaro
Comptroller General of the United States
U.S. Government Accountability Office
441 G Street NW
Washington, DC 20548

Dear Comptroller General Dodaro:

On January 10, 2020, the Government Accountability Office (GAO) notified Rep. Abby Finkenauer (IA-01) and other members of Congress that it has accepted their request to review matters relating to the approval of small refinery exemption waivers under the Renewable Fuel Standard (RFS), including the Department of Energy's (DOE) viability scores for the 40 small refinery waivers reviewed by the DOE for the 2018 compliance year.

In the request, Rep. Finkenauer and her colleagues state that "[a] comprehensive review is needed to ensure appropriate oversight going forward as well as ensuring the transparency of the EPA's process." We agree. For that reason, we ask GAO to expand its review of this program to address the following questions in a *single* standard performance audit:

1. Pursuant to section 1501 of the Energy Policy Act of 2005 (Public Law 109-58; 119 Stat. 1073; 42 U.S.C. 7545(o)(9)(A)(ii)(I)), DOE prepared and adopted its March 2011 "Small Refinery Exemption Study." Under what, if any, statutory authority, did DOE prepare and adopt its May 2014 "Addendum to the Small Refinery Exemption Study"?

2. What has been the practical effect of the 2014 Addendum and the changes to DOE's evaluation process and scoring methodology for small refineries petitioning for hardship relief? Has the 2014 Addendum and the changes to DOE's evaluation process and scoring methodology made it more difficult for small refineries to earn DOE's recommendation in favor of partial or full relief? If so, how?

3. Since 2014, has DOE made any other changes to its evaluation process and scoring methodology for small refineries petitioning for hardship relief? If so, what are those additional changes to DOE's evaluation process and scoring methodology?

4. Pursuant to what, if any, statutory authority did DOE adopt these additional changes? What has been the practical effect of the additional changes for small refineries petitioning for hardship relief? Have the changes made it more difficult for small refineries to earn DOE's recommendation in favor of partial or full relief? If so, how?

5. When scoring metric 1.a. ("Access to capital/credit"), does DOE assume that a parent entity will necessarily provide access to capital and credit to a subsidiary small refinery?

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If so, is that an accurate assumption? Has DOE always made this assumption or has DOE scored this metric differently in the past? If DOE has changed its assumption and scored this metric differently in the past, what prompted this change?

6. When scoring metric 1.b. ("Other business lines besides refining and marketing"), DOE has determined that producing asphalt and lube oils from crude oil is not "refining." On what basis has DOE made this determination? Is DOE's determination consistent with its instructions for complaint in the DOE PI-588 survey form and the agency's definition of refining? Has DOE always excluded the production of asphalt and lube oils when scoring this metric in the past? If not, what prompted this change?

7. Since 2011, when scoring metrics 1.c. ("Local market acceptance of Renewables") and 2.b. ("Renewable fuel blending (% of production)"), DOE has only examined local market acceptance of E10 and the blending of E10, respectively. DOE has not scored the following metrics:

   1.c.ii. ("Local market acceptance of Renewables - E85"),
   1.c.iii. ("Local market acceptance of Renewables - Biodiesel"),
   2.b.ii. ("Renewable fuel blending (% of production) - Biodiesel blending (not used)") and
   2.b.iii. ("Renewable fuel blending (% of production) - Other Advanced Biofuel blending (not used)").

   Why has DOE not developed the data to score metrics 1.c.ii., 1.c.iii., 2.b.ii., and 2.b.iii.? If DOE fails to score metrics 1.c.ii., 1.c.iii., 2.b.ii., and 2.b.iii., can DOE fairly assess the RFS's impact on small refineries, including those that produce high amounts of diesel?

8. After DOE divides the viability score by three (the total number of viability metrics), DOE then divides again by two. Why does DOE divide again by two?

9. Has DOE changed its interpretations of any metrics or changed scores for individual small refineries in response to federal court rulings in litigation, challenging the denial of hardship relief? If so, please explain how DOE has changed its interpretations of any metrics or changed scores for individual small refineries.

10. Does DOE staff evaluate and score small refinery petitions for hardship relief, itself, or does DOE use an outside contractor to evaluate and score small refinery petitions?

11. If DOE uses one or more outside contractors, which contractors has DOE employed?

12. Does DOE's contractor(s) have any past or current commercial relationships with entities within the biofuel industry? If so, please describe those commercial relationships.

13. What, if any, protocols does DOE have in place to protect confidential business information and other sensitive information about the small refineries petitioning for hardship relief? Do these protocols apply to DOE's contractors?

14. What, if any, protocols does the Environmental Protection Agency (EPA) have in place to protect confidential business information and other sensitive information about the small refineries petitioning for hardship relief?

15. Has Secretary of Agriculture, Sonny Perdue, Deputy Secretary of Agriculture, Stephen Censky, or others at the Department of Agriculture (USDA) attempted to obtain from EPA or DOE confidential business information or other sensitive information about the small refineries petitioning for hardship relief? If so, please describe these efforts.

16. In a series of articles, beginning in January 2018, Jarret Renshaw of *Reuters* appeared to obtain the total number and then the identity of some small refineries petitioning for hardship relief. Did this information come from EPA, DOE, DOE contractors, or USDA?

17. Does GAO agree that failure to protect the identity of a small refinery, which has petitioned for hardship relief, could give entities selling refined petroleum products in the same market as the small refinery a competitive advantage over that small refinery?

18. Does GAO agree that failure to protect the identity of a small refinery, which has petitioned for hardship relief, could give entities selling renewable identification numbers (RINs) to the small refinery the ability to extract a higher price for RINs from that small refinery?

19. The Clean Air Act authorizes "the Administrator [of EPA], in consultation with the Secretary of Energy," to act on small refinery hardship relief petitions. The nonpartisan Congressional Research Service (CRS) has stated that "[i]n light of the Secretary of Agriculture being included with the Secretary of Energy in the other consultation requirements in the statute, a court would likely interpret the exclusion of the Secretary of Agriculture from the small refinery exemption provisions as intentional and find that Congress intended that only the Secretary of Energy be consulted for those exemptions."

    Does GAO agree with CRS that the Act does not give the Secretary of Agriculture authority over small refinery hardship relief petitions?

20. Has anyone at the U.S. Department of Agriculture (USDA) attempted to influence DOE's evaluation process, scoring methodology, and recommendations on small refinery petitions for hardship relief? If so, please describe these efforts.

21. Has anyone at USDA attempted to influence, directly or indirectly, EPA's evaluation process or decisions related to small refinery petitions for hardship relief? If so, please describe these efforts.

22. Prior to his confirmation, Deputy Secretary of Agriculture, Stephen Censky, served as Chief Executive Officer of the American Soybean Association for 21 years. Given that approximately 30 percent of U.S. soybean oil is used for biodiesel production, does Deputy Secretary Censky's work on the RFS, including *but not limited to* his efforts to

increase biodiesel mandates, present a conflict of interest or the appearance of a conflict of interest?

Thank you in advance for your consideration. If you have any questions or would like to discuss these issues further, please contact Justin Memmott, who may be reached at 202-224-6389 or by e-mail at justin_memmott@epw.senate.gov.

Sincerely,

John Barrasso, M.D.
Chairman
U.S. Senate Committee on
Environment and Public Works

Shelley Moore Capito
United States Senator

Michael B. Enzi
United States Senator

Mike Lee
United States Senator

John Kennedy
United States Senator

Roger F. Wicker
United States Senator

Steve Daines
United States Senator

James M. Inhofe
United States Senator

James Lankford
United States Senator

Pat Toomey
United States Senator

CC: Dan Brouillette, Secretary of Energy
Andrew Wheeler, Administrator, Environmental Protection Agency

Senate Committee on Environment and Public Works
Hearing Entitled, "*The Environmental Protection Agency's Renewable Fuel Standard: Challenges and Opportunities*"
February 16, 2022
Questions for the Record for LeAnn Johnson Koch

Senator Carper:

1. In your testimony, you discussed the difficulties of small refineries passing on the costs of the renewable identification numbers (RINs) and compliance of the RFS to consumers. Have you heard of similar difficulties from some of the larger merchant refineries, who are not integrated? If so, can you please provide further details on why these larger merchant refineries also may be having a difficult time passing on RIN prices to consumers?

Hardship is caused by, among other things, limitations on an obligated party's ability to blend renewable fuel and generate RINs through blending. Achieving compliance through blending is significantly less expensive than buying RINs for compliance, particularly in today's near record high RIN market. Thus, merchant refiners that lack downstream integration and retail would be significantly harmed in a high-priced RIN market.

That harm is compounded for small refineries because they disproportionately produce diesel fuel and biodiesel is blended with diesel at much lower rates than ethanol is blended with gasoline. Therefore, refineries that disproportionately produce diesel generate fewer RINs for compliance and have a significantly higher cost of compliance. The Department of Energy (DOE) described this as the diesel disparity and explained that small refineries would be unable to avoid the harm because they lack the capital to make investments in renewable fuel blending.[1]

While only small refineries are eligible to petition for hardship relief from the RFS, Congress provided other mechanisms to provide relief where implementation of the RFS would "severely harm the economy or environment of a State, a region, or the United States" as it is today. 42 U.S.C. § 7545(o)(7)(A)(i). The Governors of Louisiana, Montana, Oklahoma, Pennsylvania, Texas, Utah, and Wyoming requested that EPA waive the renewable blending volumes for 2019, 2020, and/or 2021 due to severe economic harm to their states caused in part by the increasing renewable fuel blending requirements and escalating RIN prices. Senators Inhofe, Lummis, and Wicker were among a group of 13 Senators that filed a letter in support of these petitions. Separately, the National Wildlife Federation filed a petition in support of the arguments regarding economic harm and also asserting environmental harm inflicted by the RFS as an independent basis for a waiver. EPA was required to issue decisions on the petitions within 90 days of receipt, which it failed to do. § 7545(o)(7)(B).

2. During the Obama Administration, on average, how many small refinery waivers were granted annually by EPA?

[1] *See* Small Refinery Exemption Study: An Investigation into Disproportionate Economic Hardship, U.S. DEPARTMENT OF ENERGY at 23, 34 [hereinafter "2011 DOE Study"].

On average, the Obama Administration granted 14 petitions annually for the 2011 through 2015 compliance years. See the table below:

Compliance year	Number of petitions **received**	Number of petitions **granted**
2011	42	24
2012	41	23
2013	30	8
2014	28	8
2015	28	7
2016	29	19
2017	37	35
2018	44	31
2019	32	Pending
2020	30	Pending
2021	5	Pending

As Senator Cramer noted during the hearing, "lazy legislating" led to EPA having "an awful lot of leeway to determine things like RVOs, even when they are stated in the law."[2] EPA has abused its discretion over the small refinery hardship relief process: "for four years, it is one way, then for four years, it is another way, and then for four years, it is another way."[3] The ebb and flow of hardship relief has coincided with changes in administration, rather than the RIN market and actual hardship experienced by small refineries. With the most recent change in administration, EPA now proposes both to claw back hardship relief granted during the Trump administration and to erase the small refinery hardship program altogether. The 2011 DOE Study, commissioned by Congress, found that hardship would grow increasingly acute as the volume mandates increase, reaching the blend wall and driving up the price of RINs.[4] EPA's proposed action directly contradicts Congress's will when it provided small refineries the ability to petition for relief at any time.

Ranking Member Capito:

1. How important are liquid fuels?

    a. Do you think liquid fuels are going away anytime soon?

Congress intended the RFS program to promote American energy independence.[5] To meet that goal, American refineries must continue producing domestic diesel and gasoline. While the U.S. broadens its portfolio of alternative fuels, domestic energy independence must remain a priority. When access to liquid fuels is perceived to be threatened, it leads to volatile economic conditions. This has been made clear by the ongoing Russian invasion of Ukraine, which has

[2] Senate Committee on Environment and Public Works, "The Environmental Protection Agency's Renewable Fuel Standard: Challenges and Opportunities," Hearing Transcript at 57 (Feb. 16, 2022).
[3] *Id.* at 58.
[4] *See* 2011 DOE Study at 17–18.
[5] *See Renewable Fuels Assoc. v. EPA*, 948 F.3d 1206, 1216–18 (10th Cir. 2020).

destabilized the oil market. The importance of energy independence, including *liquid fuel* independence, could not be clearer than it is right now.

The petroleum refining industry provides thousands of jobs across the country. The extent to which Americans, particularly rural Americans, rely on these jobs should not be underestimated. Neither should the importance of liquid fuels to the economy. There are approximately 1.2 billion internal combustion engine vehicles in the world, 250 million of those in the United States. The continued availability of those vehicles matters to low-income Americans who cannot afford more expensive electric vehicles (and the expensive electricity required to power them), as well as the long-haul transportation industry, given the inability of electric vehicles to meet the needs of that industry absent a dramatic change to the electric grid, which would take years, if not decades, to achieve.

Any transition to alternative sources of fuel will require extensive infrastructure and a tremendous economic shift. It will take time for alternative fuels to become economically viable and accessible for most Americans. As an example, a recent report indicates that the global demand for batteries is likely to outpace the supply by 40% by 2030, with more than half the total demand coming from batteries for electric vehicles.[6] At the same time, the domestic solar industry is predicting that rising costs could slow its expansion, and Russia's role as a major nickel producer could have implications for solar, which is increasingly paired with lithium-ion batteries and stainless steel, both of which contain nickel.[7]

EPA continues to push liquid *biofuels* through the RFS, despite that fact that the program is not operating as intended. EPA has failed to adjust the renewable blending volumes to reflect market realities. For example, the 2020-2022 renewable blending volumes do not reflect the fact that cellulosic biofuel production in the United States has failed to develop, and production of advanced biofuel that is not cellulosic biodiesel, biomass-based diesel, or sugarcane ethanol has remained small. By failing to lower the renewable blending volumes to appropriate levels, EPA has caused the RIN market to become illiquid. EPA even acknowledges in its proposed RFS renewable fuel blending volumes for 2020-2022 that the RIN market currently is illiquid, that there is a shortfall of available RINs, and that RINs are not in the hands of the parties that need them for compliance.[8] EPA also has acknowledged that RIN prices are not merely the result of the supply and demand for RINs themselves, but "are a function of multiple factors including but not limited to changes in petroleum prices, agricultural feedstock (e.g., corn, soy) prices," as well

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[6] EVs, renewables to create battery supply gap by 2030 — report, E&E NEWS (Mar. 10, 2022), available at https://subscriber.politicopro.com/article/eenews/2022/03/10/evs-renewables-to-create-battery-supply-gap-by-2030-report-00014240.

[7] Rising costs threaten U.S. solar growth — report, E&E NEWS (Mar. 10, 2022), available at https://subscriber.politicopro.com/article/eenews/2022/03/10/rising-costs-threaten-u-s-solar-growth-report-00015681.

[8] Renewable Fuel Standard (RFS) Program: RFS Annual Rules, 86 Fed. Reg. 72436, 72455 (Dec. 21, 2021) ("Proposed Volumes Rule"):

> . . . [I]t may be challenging for the market to satisfy the 2022 annual standards and the 2022 supplemental standard entirely with renewable fuel use in 2022. Given this, the projected shortfall in RIN generation in 2019, and the uneven holding of carryover RINs among obligated parties, we expect that further increasing the standards with the intent to draw down the carryover RIN bank would lead to significant deficit carryovers and potential noncompliance by some obligated parties that own relatively few or no carryover RINs.

as EPA's own manipulation of "RFS standards and expectations of future EPA policy decisions."[9]

The RFS program is not working as Congress intended. It is instead driving up costs for merchant and small refineries and fuel prices for consumers. The program is encouraging oligopolies by distorting competition and turning a blind eye to the harm the program is inflicting on small refineries that do not control the downstream blending of their fuel. Despite its knowledge that the program is not operating as intended, EPA has done nothing to improve its implementation of the program, including ensuring a stable RIN market. And EPA's latest proposal to strip small refineries of the ability to receive hardship relief will further destabilize small refineries at a time when their production is critical to the energy independence of our great country.

Small refineries now face potential shutdown and bankruptcy, which would not only harm the small refineries, but also their employees, the rural communities they serve, and both regional and national energy security. Rural communities are dependent on the fuel and the jobs that their small refineries provide. As small refineries shutter, their fuel will be replaced by fuel that is either imported or produced by already-large refiners.

Now, more than ever, EPA must implement the RFS as Congress intended, providing relief to small refineries consistent with the extensive evidence of disproportionate economic hardship and the findings of the 2011 DOE Study.

2. The 117th Congress is considering several energy tax provisions. Among these are enhanced tax credits for various kinds of alternative fuels and advanced biofuels, including for sustainable aviation fuel. Do you have any concerns that more favorable tax treatment for subcategories like sustainable aviation fuel may have unintended consequences for other types of transportation fuels, such as biodiesel and renewable diesel, that compete for the same input feedstocks?

    a. What potential implications do these sorts of preferential policies have for supply and demand of other biofuels, prices for consumers buying these fuels, as well as the broader transportation fuel sector's ability to meet requirements under the RFS?

Congress should look holistically at all programs and direct credits—and thus taxpayer dollars—toward fuels that reduce carbon emissions. Many of the highly beneficial technologies being explored/developed have weak, negative, uncertain, or volatile future cash flows, impairing investment in those technologies by institutional, industry, and private investors. The technologies therefore require incentives and support.

The federal government should proceed thoughtfully as it considers enhanced tax credits, because on their own, they will not solve the fundamental problems underlying the RFS program as currently structured and implemented by EPA. As explained in the 2011 DOE Study, tax incentives do not wholly counteract high renewable fuels production costs and low market

[9] Modifications to Fuel Regulations To Provide Flexibility for E15; Modifications to RFS RIN Market Regulations, 84 Fed. Reg. 27013 (Jun. 10, 2019).

acceptance.[10] And even if tax credits served to benefit certain market players, they would not benefit small refineries that cannot increase their blending of renewable fuels.

Senator Shelby:

1. Mrs. Koch – Several of my colleagues and I were in Congress when the renewable Fuel standard (RFS) was developed. Congress knew then that we needed to apply the RFS rules differently in certain areas. My recollection is that we anticipated small refineries would be exempt from obligations as long as we had the RFS program or until technological advances made it possible to blend fuels in more places at significantly lower cost.

   This position was captured by the language of the Clean Air Act that was crafted to allow refineries to be able to apply for, and receive, waivers from the RFS. Further, the bill established a process for both petitioning for such waivers as well as the process for administrative review of the petitions. The Committee Report for S.606, the Reliable Fuels Act clearly explained the exemption process thereby demonstrating that its inclusion was no accident.[11] Furthermore, past actions by the Environmental Protection Agency (EPA) have also clearly demonstrated that the agency understood this waiver charge by Congress through historical grants of waivers for small refineries.

   However, EPA's recent proposal[12] to issue a blanket denial of all pending waiver requests as well as the already-issued exemptions for 2018 blatantly conflicts with Congressional intent and past agency acknowledgment of that intent. EPA's recent proposal also demonstrates that the agency believes it can unilaterally apply certain statutory provisions and ignore others as the agency sees politically advantageous. That said, is there anything in the Clean Air Act or in the legislative history surrounding the establishment of the small refinery exemption provisions that indicates these waivers would only be available for a few years?

No, just the opposite. The Clean Air Act provided for initial "temporary exemptions" from the RFS renewable fuel blending mandates, for all small refineries, that were effective from the outset of the program through 2010, 42 U.S.C. § 7545(o)(9)(A)(i), and then provided an additional two-year extension of the "temporary exemptions" to certain small refineries based on a study performed for Congress by the Department of Energy. These blanket "temporary exemptions" ended at the end of the 2012 compliance year in accordance with § 7545(o)(9)(A)(ii).

After the blanket temporary exemptions expired, each "small refinery" was permitted to petition for hardship relief "at any time" based on a showing of disproportionate economic hardship to the individual refinery. § 7545(o)(9)(B). Through the petition process, the Administrator of EPA is required to evaluate the merits of the individual small refinery's hardship petition, in consultation with DOE (not the USDA, the White House, the biofuels industry, large market competitors, the public, or others that have attempted to inappropriately

[10] *See* 2011 DOE Study at 14–15.
[11] https://www.congress.gov/109/crpt/srpt74/CRPT-109srpt74.pdf
[12] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1013KMM.pdf

influence the process)[13], and EPA is required to consider the findings of the DOE 2011 Study in making its decision whether to grant small refinery hardship relief.

This process was in place for the past decade until EPA, in a dramatic about-face following a change in administration, took aim at small refineries through an illegal, retroactive "adjudication", years after its statutory deadline to decide pending small refinery hardship petitions had expired. EPA's proposed denial of all pending small refinery hardship petitions not only violates the Clean Air Act and administrative rulemaking process, but also rejects DOE's advice that doing so risks the shutdown and bankruptcy of small refineries. DOE did not waiver and issued individual hardship scores for each petitioning small refinery.

In evaluating small refinery hardship petitions for 2019, DOE concluded that for all (or almost all) small refineries they would be in jeopardy without relief:

> The demand reduction brought about by COVID-19 has resulted in low refinery crude runs and low refinery margins as refineries compete for the available demand. Refinery rationalizations are expected as a result of reduced demands, low refining margins, **and the escalating price of RINs**. **It is anticipated that petitioner faces burdens that could cause bankruptcy or closure**.[14]

Notwithstanding its obligation to consult with DOE and DOE's response to EPA that all (or almost all) small refineries would be at risk of bankruptcy or closure if they were denied hardship relief, EPA rejected DOE's advice and has proposed not only to deny hardship relief to all small refineries for the 2019-2021 compliance years, but to claw back relief already granted for the 2018 compliance year based on its novel theory that every refinery has exactly the same cost of compliance and no refinery is disproportionately impacted. EPA's novel theory is exactly the opposite of DOE's conclusion that small refineries are at risk of bankruptcy and shutdown due to escalating RIN costs. Economists describe EPA's claim as implausible and unsupported[15], and an empirical analysis using daily bulk sales data from 2019-2021 directly refutes EPA's conclusions relying on prior years data and a flawed, overly simplistic, and outcome driven "analysis" of RIN cost pass-through[16].

Aside from the clear language in the Clean Air Act indicating that small refineries can apply for exemptions "at any time" after the original "temporary exemptions" ended, there is further proof that hardship relief was not intended to be temporary. DOE explained to Congress that small refinery hardship relief would grow increasingly acute as the volume mandates

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[13] For discussion of USDA's attempts to improperly influence the hardship decision making process, *see, e.g.*, letter from L. Johnson Koch, Perkins Coie, to G. Dodaro, Comptroller General of the United States (Nov. 3, 2021) [Tab A].

[14] *See* attached excerpt from DOE 2019 consultation with EPA (emphasis added) [Tab B].

[15] *See* Cody Nehiba, Ph.D. & Gregory B. Upton Jr., Ph.D., Comment: U.S. Environmental Protection Agency's Proposed RFS Small Refinery Exemption Decision, Louisiana State University Center for Energy Studies (Feb. 7, 2022) [Tab C]; Timothy Fitzgerald, Ph.D., Comments on EPA Proposed RFS Small Refinery Exemption Decision (Feb. 7, 2022) [Tab D]. Dr. Nehiba and Dr. Upton are Associate Research Professors at the Louisiana State University Center for Energy Studies. Dr. Fitzgerald is an Associate Professor at the Rawls College of Business at Texas Tech University.

[16] *See* Timothy Fitzgerald, Ph.D., Empirical Analysis (Feb. 7, 2022) [Tab E].

increased. DOE expected that small refineries would be significantly harmed, as the blend wall was reached, due to limitations on small refineries' ability to blend. The DOE Study says:

> As the RFS mandate increases, obligated parties will demand more RINs, adding upward price pressure. As the mandate increases, increasing the supply of RINs becomes difficult or nearly impossible. In anticipation of the blend wall, obligated parties may stockpile RINs through discretionary blending in anticipation of a shortage of blending opportunities. Those parties that are short, i.e. cannot generate enough RINs through their own facilities to meet their RVO, will need to purchase RINs and could suffer **significant economic hardship**.
>
> Declining ethanol prices would probably be favorable to refiners/blenders that predominately blend ethanol rather than purchase RINs for blending. Many small refiners do not retain control over the blending of their products, and must purchase additional RINs. Obligated parties that rely on purchasing RINs **would be adversely affected when the blend wall is reached and their RINs inventory has been depleted**.[17]

Congress intended for hardship relief to be available "at any time", not to end when the harm was expected to be the most acute. And the United States Supreme Court upheld this logic, finding that if Congress intended the small refinery hardship relief provision to be a sunset provision, under which small refineries' ability to seek relief due to disproportionate economic hardship had a time limit, then Congress chose "an odd way to achieve it."[18]

a. Is there any support or historical basis for EPA issuing a blanket denial of all pending small refinery petitions for exemption or does the statute mandate reviewing each individual petition on its respective merits?

The Clean Air Act requires EPA to review individual petitions on their merits. After the initial "temporary exemptions" pursuant to 42 U.S.C. § 7545(o)(9)(A) at the outset of the program expired, the only mechanism to secure hardship relief after 2012 was for "a small refinery" to submit a petition to EPA under § 7545(o)(9)(B)). After the submission of the petition by a small refinery, EPA has 90 days to grant or deny the small refinery's petition. § 7545(o)(9)(B)(iii).

The only reason EPA is currently poised to issue a mass adjudication issuing retroactive denials for multiple compliance years is that EPA ignored its statutory obligation to decide petitions 90 days from the date of the submission of the petition by the small refinery, repeatedly violating the Clean Air Act over multiple years. In total, EPA has separately violated the Clean Air Act 65 times over a three-year period. If EPA complied with its statutory duties, it would be impossible to issue a mass adjudication or blanket denial because each petition would have been decided years ago on its own merits, within 90 days, and after consultation with DOE.

b. What will the impact on small refineries experiencing a financial hardship be if EPA finalizes the agency's rule as proposed?

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[17] DOE Study at 17–18 (emphasis added).
[18] *HollyFrontier Cheyenne Ref., LLC v. Renewable Fuels Ass'n*, 141 S. Ct. 2172, 2180 (2021).

As EPA explained on December 21, 2021, there was a shortfall in RIN generation in 2019 and "uneven holding of carryover RINs among obligated parties," which means there are not enough RINs for 2019-2021 compliance.[19] "Uneven holding of carryover RINs among obligated parties" is a way of saying that RINs are not in the hands of the parties that need them for compliance—small refineries. They are instead being held by large integrated refiners and exempt, non-refining blenders, expecting to earn windfall profits when small refineries are forced to comply and buy RINs at usurious prices on the eve of the compliance deadlines. And, the reason small refineries are going to have to buy RINs on the eve of the compliance deadlines is that EPA ignored its statutory duty 65 times to timely decide small refinery hardship petitions within 90 days of receipt.

If EPA finalizes the agency's proposal, small refineries will have three choices: (1) pay usurious prices to large integrated oil companies to buy RINs, placing a financial strain on the company and using up precious working capital or available liquidity to do so; (2) violate the law and become a target of EPA enforcement, or (3) be forced to shut down, similar to Philadelphia Energy Solutions, because they will not be able to afford to continue operating and buying RINs.

Small refinery shutdowns would destroy thousands of union jobs and the rural communities they support and thereby impose catastrophic losses on the economy due to the loss of millions of dollars in tax revenue to state and local governments, as well as the increase in prices for gasoline and diesel at a time when household budgets already are stretched thin in the face of the highest inflation rate in 40 years.

c. How is that impact exacerbated by the compressed compliance timeframe in the agency's proposed rule?

EPA's timeframe robs small refineries of the ability to plan for compliance, making them even more reliant on the RINs accumulated by large integrated refiners and non-obligated entities, just as their delays in establishing RVOs have created RIN shortages.

d. What is the potential impact on fuel prices if EPA finalizes the agency's proposed decision?

If EPA succeeds in its politically motivated efforts to shut down or bankrupt small refineries, it will not only harm small refineries and the rural communities and states in which they operate, it will also harm the U.S. economy as a whole, as well as consumers who will pay the price at the pump. The impact of higher fuel prices means increased transportation costs, affecting prices down the supply chain, including those for everyday goods and food in grocery stores. If small refineries are required to jump into the market to buy RINs from large integrated oil companies, at near record high prices, drawing down the already depleted RIN bank, it will cause RIN prices and fuel prices to skyrocket. Since it is impossible for any more biofuel to be blended in compliance years 2018-2021, the extraordinary harm that EPA is actively pursuing, will be harm for harm's sake. Bi-partisan leadership is needed to stop this reckless course of action.

[19] 86 Fed. Reg. 72436, 72455 (Dec. 21, 2021).

2. With Russia's invasion of Ukraine, the future of the global oil market becomes more uncertain. As such, protecting domestic sources of oil seems more important than ever. What role do small refiners play in helping the U.S. protect national security as it relates to fuel dependency during uncertain times like this?

Many small refineries operate in rural areas and process local crudes to produce gasoline and diesel that are sold in the local area surrounding the refineries. Thus, small refineries not only contribute to the domestic fuel supply, but they are also often the only source of fuel to the rural communities they serve. Should small refineries shutter, their communities' access to fuels will become inefficient and expensive, requiring long haul trucking at considerable expense to the consumer, and the security of product supply would be reduced in those rural areas because supply chains would be extended, which increases the risk of disruption.

a. What role do small refiners play in helping to keep oil prices reasonable through times like these?

Small refineries provide a critical source of fuels across the country, with particular importance in rural communities. Many rural communities served by small refineries have no efficient, alternative fuel supplies. If small refineries are denied hardship relief and therefore must spend tens or even hundreds of millions of dollars to purchase RINs to comply with the RFS obligations for 2018-2021, some small refineries will face bankruptcy and/or closure. And if small refineries shutter, refined products will be diverted to their rural communities from other cities at higher prices given transportation costs, thereby depleting certain cities' supply and increasing prices across the country. As a result, domestic fuel production will decrease, and small refineries' fuel will be replaced by fuel that is either imported or produced by large integrated refiners, transforming those already-large refiners into multi-national oligopolies.

Senator Wicker:

1. In December, the Environmental Protection Agency (EPA) issued a proposed rule that would deny outstanding small refinery hardship petitions. I understand that the proposed blanket denial includes three petitions from 2018. Refineries demonstrate their compliance with the Renewable Fuel Standard through Renewable Identification Numbers (RINs), which are only "good" for two years. How would a refinery that applied for relief in 2018 even find RINs to comply in 2022?

2017- and 2018-vintage RINs necessary to demonstrate compliance for 2018 are no longer available. RINs are only valid in the year in which the blending occurred and the following year. Therefore, it is impossible for a small refinery to buy RINs for 2018 compliance.

It is not only the three pending hardship petitions for the 2018 compliance year at issue in EPA's proposal to deny small refinery hardship relief, but also all of the *previously granted* 2018 hardship petitions. On December 8, 2021, the day after EPA issued its proposal, the U.S. Court of Appeals for the D.C. Circuit remanded the 2018 small refinery hardship relief to the Agency at the Agency's request.[20] On January 3, 2022, nearly a month after the remand and nearly

[20] Order, *Sinclair Wyo. Refin. Co. v. EPA*, No. 19-1196 (D.C. Cir. Dec. 8, 2021), Doc. No. 1925942.

halfway through the comment period for EPA's proposal, EPA notified small refineries that the Agency was considering including the 2018 small refinery hardship relief as part of the proposal, which would result in the reversal of more than 30 hardship decisions.

Reconsidering *already granted* petitions is unprecedented and unlawful. In addition, it would serve no regulatory purpose. Moreover, small refineries relied on the 2018 small refinery hardship relief to their detriment.[21] Refineries reasonably relied on EPA's final decisions, sold or carried forward any RINs they might have had at the time, and developed capital budgets and made expenditures based on having received relief. To reverse already-granted petitions, and spend the time and resources defending that reversal, would solidify EPA's departure from merit-based decision-making.

2. In your written testimony, you included a chart on page two showing the correlation between blending and small refinery exemptions during the years when the most hardship relief was granted. Does small refinery hardship relief cause any more or less blending of ethanol?

Small refinery hardship relief has no impact on the amount of ethanol blending. Small refineries blend as much ethanol as they can because it is less expensive than buying RINs, but they do not control the downstream blending and retail sale of their gasoline. Therefore, small refineries blend ethanol with the gasoline they sell across their rack at the refinery and downstream blenders blend ethanol into the product sold downstream. Small refineries located in rural locations often can only sell a small portion of their production across the rack due to limited local demand and are forced to ship most of their product unblended on pipelines (which prohibit shipping of blended fuel due to pipeline integrity concerns) to downstream blenders, thereby transferring the ability to blend—and generate a RIN—to such downstream blenders while leaving the small refinery hostage to purchasing RINs.

Small refineries are always incentivized to blend. If they receive hardship relief, they can carryover RINs for future compliance years. If they are denied relief, they need RINs for compliance. So, hardship relief does not disincentivize blending. In addition, small refineries do not know in advance whether they will receive hardship relief.

Exempting small refineries does not affect whether the fuel they produce is blended with ethanol—their fuel is either blended with ethanol by the small refinery, if possible, or blended downstream by those with the capacity to blend. Rather, it merely prevents small refineries from transferring millions of dollars' worth of RINs to large integrated refiners and nonobligated blenders and retailers. That is especially so for the 2018 through 2021 compliance years at issue in EPA's proposal to deny small refinery hardship relief. For each of those years, the renewable fuel blending has been completed. Thus, a wholesale denial of hardship relief for those years

[21] *See, e.g.*, *Citizens Against Pellissippi Parkway Extension, Inc. v. Mineta*, 375 F.3d 412, 418 (6th Cir. 2004) ("detrimental reliance on the previous [agency determination] would militate against allowing the agency to withdraw" it); *see also Rosebud Sioux Tribe v. Gover*, 104 F. Supp. 2d 1194, 1201 (D.S.D. 2000) (declining to accord the BIA the inherent authority to reconsider its approval of a lease of tribal land, in part because the developers had "already spent more than $5,000,000 in reliance on [the Bureau's] action[s]"), *rev'd on other grounds sub nom. Rosebud Sioux Tribe v. McDivitt*, 286 F.3d 1081 (8th Cir. 2002); *Prieto v. United States*, 655 F. Supp. 1187, 1188 (D.D.C. 1987).

only serves to force small refineries to transfer their wealth which, in turn, threatens the viability of these refineries and their communities.

TAB A

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The Honorable Gene L. Dodaro
Comptroller General of the United States
U.S. Government Accountability Office
441 G Street NW
Washington, DC 20548

Re: GAO Inquiry Into Renewable Fuel Standard's Small Refinery Hardship Program

Dear Comptroller General Dodaro:

The Small Refineries Coalition (Coalition) writes to apprise the Government Accountability Office (GAO) of additional information it should consider during its ongoing review of small refinery hardship decision making under the Renewable Fuel Standard (RFS). For GAO's inquiry to be complete, it must investigate the efforts by the United States Department of Agriculture (USDA) to influence the hardship decision making process.[1] USDA has attempted to influence the decision making process in the past, and there is a risk that it (or other agencies or outside interests) will do so again in the future. GAO should, therefore, investigate these attempts that contravene the clear language of the Clean Air Act (CAA), which authorizes only the Environmental Protection Agency (EPA), in consultation with the Department of Energy (DOE), to participate in small refinery hardship decision making.

The Coalition's efforts to gain access to records of communications between USDA and EPA regarding small refinery hardship decision making, pursuant to the Freedom of Information Act (FOIA), have been unsuccessful. Ultimately, after a two-year effort, we secured only a handful of largely redacted documents. The GAO, however, has statutory authority to obtain unredacted records from agencies as part of its investigation. *See* 31 U.S.C. § 716(a)(1) (the Comptroller General is "authorized to obtain such agency records as the Comptroller General requires to discharge the duties of the Comptroller General…."); § 716(a)(2) (agencies are directed to provide "Comptroller General information the Comptroller General requires about the duties, powers, activities, organization, and financial transactions of the agency. The Comptroller General may inspect an agency record to get the information."). These records are necessary to GAO's ability

[1] On January 30, 2020, Senator Barrasso and nine other senators requested that GAO expand its investigation to address additional aspects of small refinery hardship relief, including how the scoring of hardship petitions has affected small refineries and the extent to which inappropriate political influence is affecting the implementation of the program. *See* Letter from Sen. Barrasso, et al., to Comptroller General Dodaro (Jan. 30, 2020).

to determine whether USDA exerted improper influence over the small refinery hardship decision making process, and GAO has the statutory authority to review them.

Media reports indicated that USDA tried to influence EPA to reduce the number of small refinery hardship decisions it granted for the 2018 compliance year. For example, prior to the issuance of EPA's decisions, former Secretary of Agriculture Sonny Perdue was tasked with reconsidering the Administration's approach to granting hardship relief to small refineries.[2] And roughly one week after the 2018 hardship decisions were released, former President Trump held a meeting to discuss those decisions with not only former Administrator Wheeler, but also officials from USDA, including the Secretary and former Deputy Secretary of Agriculture Stephen Censky[3], as well as Terry Branstad, the Ambassador to China at that time and former Governor of Iowa—the largest corn producer in the United States.[4]

As a matter of law, any influence from USDA is improper. The CAA does not give USDA *any* authority or role over small refinery hardship decision making. *See* 42 U.S.C. § 7545(o)(9)(B)(ii) (the CAA authorizes *only* "the Administrator [of EPA], in consultation with the Secretary of Energy," to act on petitions from small refineries). There is no valid rationale for USDA's attempts to influence the decision-making process. Members of Congress objected to USDA's influence, but the extent of the inappropriate influence is not fully known.[5]

Our efforts to understand the extent of the influence have largely been unsuccessful. In August 2019, the Small Refineries Coalition submitted two FOIA requests to USDA, requesting copies of all communications between USDA and EPA, and between USDA and Ambassador Branstad, regarding small refinery decision making.[6] It is clear from the records we received[7] that USDA officials—including Secretary Perdue and Deputy Secretary Censky—frequently communicated with EPA regarding small refinery hardship relief, despite the fact that the CAA

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[2] *See* Rob Hotakainen and Marc Heller, Trump under growing pressure to block refinery waivers, E&E GREENWIRE, June 21, 2019; *see also* Chris Clayton, Backlash Over Perdue Influence: Senators Want President to Keep Ag Secretary Out of EPA Small-Refinery Decisions, PROGRESSIVE FARMER, July 1, 2019; Refiners: Restrict USDA Access to Small-Refinery Waivers Information, PROGRESSIVE FARMER, Jul. 9, 2019.

[3] Before becoming the former Deputy Secretary, Stephen Censky served as chief executive officer of the American Soybean Association for 21 years, an organization openly opposed to small refinery exemptions.

[4] *See* Jennifer Jacobs, Jennifer A Dlouhy, and Mario Parker, Trump Seeks to Allay Farm-State Uproar in Oval Office Meeting, BLOOMBERG, Aug. 20, 2019; *see also* Marc Heller, Leaked memo: Trump admin mulls effort to boost ethanol, E&E NEWS, Aug. 23, 2019.

[5] *Id.*

[6] *See* FOIA request 2019-DA-06192-F (Aug. 21, 2021) (Tab A); FOIA request 2019-OSEC-06384-F (Aug. 22, 2019) (Tab B).

[7] *See* Letter from Alexis Graves, Director of the Office of Information Affairs, USDA, to LeAnn Johnson Koch, Perkins Coie (May 25, 2021) (Tab C); Letter from Alexis Graves, Director of the Office of Information Affairs, USDA, to LeAnn Johnson Koch, Perkins Coie (June 8, 2021) (Tab D); final records production in response to FOIA request 2019-OSEC-06384-F (Tab E); excerpted final records production in response to FOIA request 2019-DA-06192-F (Tab F).

affords USDA *no* role in the hardship decision making process. It is also clear from the heavily redacted records that USDA discussed small refinery hardship relief with Ambassador Branstad and his team. The mere fact of communications with EPA regarding small refinery hardship relief is evidence of improper influence. While these communications represent a clear intention to skirt the CAA in favor of politics, the substance of the records is so heavily redacted that we do not know the full extent of the influence on behalf of the biofuels lobby.

While our efforts to obtain complete records through the FOIA process have largely been stonewalled, GAO's authority as an investigative body affords it the ability to review the unredacted records. *See* 31 U.S.C. § 716(a)(1) ("The Comptroller General is authorized to obtain such agency records as the Comptroller General requires to discharge the duties of the Comptroller General (including audit, evaluation, and investigative duties). . ."); *see also* § 716(a)(2) ("Each agency shall give the Comptroller General information the Comptroller General requires about the duties, powers, activities, organization, and financial transactions of the agency. The Comptroller General may inspect an agency record to get the information."). Without a valid legal basis justifying USDA's involvement, it is incumbent on GAO to determine the extent of any undue influence on EPA.

We also understand that both EPA and DOE have relied on Stillwater Associates, a consulting firm that also has a history of representing biofuels groups, in their evaluation of small refinery hardship petitions. If DOE and EPA do, in fact, rely on consultants to evaluate hardship petitions, the agencies should rely only on contractors that are neutral, independent parties that do not have an interest in the outcome of the petitions. GAO should investigate whether Stillwater Associates is performing any duties related to the evaluation of small refinery hardship petitions and document the extent to which the accurate and impartial assessment of small refinery hardship petitions has been injured.

This inquiry is critical to uncovering the extent of improper political influence the biofuels lobby has had over the small refinery decision making process. To the extent this lobby is using USDA (or outside contractors with ties to biofuels groups) to do its bidding, it threatens the integrity of the entire program and leaves small refineries in dire circumstances despite the statutory mandate that EPA in consultation with DOE—and *only* DOE—provide relief to small refineries that suffer disproportionate economic hardship due to their RFS obligations.

I look forward to discussing this further with you at your earliest convenience. Thank you.

Sincerely,



LeAnn M. Johnson Koch

Enclosures

cc: Frank Rusco (via electronic mail)
Quindi Franco (via electronic mail)
Jaci Evans (via electronic mail)

TAB B

[redacted]

Section 3 (c) - Compliance Costs Likely to Lead to Shut-Down

Some refineries have a unique vulnerability such as a weak competitive position and any significant additional burden could cause bankruptcy or closure. This metric covers those refineries indicating that compliance may lead to such an outcome. A score of ten is awarded if the refinery is "likely to shut down" or a score of zero if not.

Refinery Score Explained

> ***The demand reduction brought about by COVID-19 has resulted in low refinery crude runs and low refinery margins as refineries compete for the available demand. Refinery rationalizations are expected as a result of reduced demands, low refining***

[redacted]

margins, and the escalating price of RINs. It is anticipated that petitioner faces burdens that could cause bankruptcy or closure. As a result, this metric is scored a ten.

TAB C

Comment: U.S. Environmental Protection Agency's Proposed RFS Small Refinery Exemption Decision

Cody Nehiba
Gregory B. Upton Jr.*

Louisiana State University
Center for Energy Studies

February 7, 2022

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Disclaimer

The Louisiana State University Center for Energy Studies (LSU-CES) was created by the Louisiana Legislature in 1982 with the stated mission of conducting, encouraging and facilitating research and analysis to address energy-related problems or issues affecting Louisiana's economy, environment and citizenry. The Center's goal is to provide a balanced, objective and timely treatment of issues with potentially important consequences for Louisiana.

LSU-CES was commissioned by Perkins Coie Law Firm LLP to provide an assessment of the plausibility of two specific questions raised in EPA (2021b) including: (1) *Are renewable fuel standards (RFS) compliance costs plausibly the same for all refineries?*, and (2) *Is it plausible that small refineries recover their compliance costs through the market price they receive when they sell their fuel to the market?*

It is important to note that there are many points made and specific data analyzed in EPA (2021b). Given the inherent quick timeline associated with the comment period, we focus on providing a broad assessment of these two major claims as opposed to analyzing particular details or ancillary points. Additional assessment and analysis of other particular details or ancillary points would of course be possible with additional time. The omission of a discussion on any specific claim made by EPA should not be interpreted as either agreeing or disagreeing. Similarly, the citation of a specific analysis or peer reviewed publication should not be interpreted as an endorsement.

Perkins Coie LLP, 20 small refineries with diverse geographic dispersion, and three anonymous academic reviewers were given the opportunity to review and provide feedback on this report. The analysis and opinions expressed, however, are those of the authors alone.

No recommendations will be made on how EPA should act. The purpose of this document is to provide an objective perspective on these two pertinent questions that might influence EPA's decision.

Executive Summary

The EPA is currently accepting comments on a proposed change to its statutory interpretation of the Clean Air Act (CAA) small refineries provisions. According to EPA, this change in interpretation would result in the denial of 65 pending petitions for small refineries to seek small refinery exemptions (SREs) from the Renewable Fuel Standard (RFS) program.

In this report, we will assess two claims made in EPA (2021b). These claims will be motivated by economic theory and then corroborated with a review of empirical research. Public data will be relied upon where appropriate. Importantly, we focus on whether these claims are plausible broadly. No assertions regarding whether the particular conditions and assumptions required for the claims to be valid hold for any one refinery in particular, or any specific refinery at all within the industry are made.

Claim 1: EPA's first claim is that the RFS compliance costs are the same for all obligated parties, and thus no party bears RFS compliance costs that are disproportionate relative to others' costs. We conclude that this claim is implausible. One economic rationale behind a tradable permit program, such as RFS, is to achieve the lowest possible compliance cost market-wide. Economic theory suggests that this least-cost outcome will occur at the point at which the *marginal*[1] compliance cost of each firm is equal to the tradable credit price (i.e. Renewable Identification Numbers, or RIN price in this context). However, equalizing marginal compliance costs across firms does not imply that the *average* compliance costs per unit of output is the same for all individual firms.

There are currently 124 refineries operating in the United States, each with idiosyncratic operating conditions and production functions. For example, refineries are located in different geographic regions across the country. Refineries in different regions serve different markets but may also have varying access to different feedstocks—both crude oil and bio-feedstocks. Even cold weather events can impact an individual refinery's ability to blend certain biofuels. Some refineries are connected to large refined-products

[1]This is, the incremental change associated with one additional unit.

pipeline systems with access to many buyers that are unavailable to other refiners. Further, the feasibility of sales into international markets, which are not subject to the RFS, varies across refineries.

In terms of production, refinery configurations are not uniform, allowing each to produce varying amounts of outputs like gasoline, diesel, or jet fuel. Gasoline and diesel are subject to RFS, while jet fuel is not. In addition, some refineries are part of integrated chemical value chains that can lead to greater operating efficiencies, and allows for greater substitutions in the share of outputs produced.

In contrast to these differences, RINs are traded nationally. Given the variation in refinery characteristics, the net effect of the RFS and changes in RIN prices on individual refineries is almost certainly different. In theory, some refineries may actually receive an overall net benefit from the RFS, while others are, on balance, negatively impacted. Again, we make no claims regarding the size of these differences for an individual firm or whether a specific refinery meets the statutory definition of disproportionate economic hardship (DEH).

Claim 2: EPA's second claim is that obligated parties, including small refineries, recover their compliance costs through the market price they receive when they sell their fuel products, and thus do not bear a hardship created by compliance with the RFS program. We conclude that this claim is partially supported, but not entirely. First, economic theory suggests that the incidence of this policy would be shared by both consumers and producers of gasoline and diesel. Because demand for fuels is relatively unresponsive to prices (i.e., inelastic), especially in the short-run, economic theory suggests that more of the RFS compliance burden will fall on consumers; however, the incidence of compliance costs is ultimately an empirical question.[2]

A number of empirical studies have tested for the pass-through of RFS costs to wholesale and retail prices (Knittel et al., 2017; Pouliot et al., 2017;

[2]In this context, we refer to "consumers" are the final users of the fuel. As will be discussed further, there are multiple firms along the value chain (i.e. biofuel producers, refineries, blenders, gasoline stations, etc), and in practice each can be impacted differently.

Burkhardt, 2019; Li and Stock, 2019; Lade and Bushnell, 2019). These studies have generally found that short-term changes in RIN prices have been passed onto consumers through fuel prices, especially to E10 prices. However, the amount of RIN pass-through has been found to vary across regions, with incomplete pass-through in the eastern U.S. (Burkhardt, 2019; Pouliot et al., 2017). Further, studies do not generally find complete RIN pass-through to retail prices for E85 (Knittel et al., 2017; Li and Stock, 2019; Lade and Bushnell, 2019).

Thus, we reached our conclusion that this claim is *partially true* considering several factors. There is evidence for pass-through of RIN prices to consumers. The EPA is correct that this price increase can offset compliance costs for refineries, *ceteris paribus*;[3] however, the implication that *because* RFS leads to increases in prices for consumers, and *thus* the program cannot impose hardship on an individual firm, is implausible in our opinion for at least three reasons. First, as discussed in response to Claim 1, not every refinery is impacted the same due to a multitude of reasons (technical, geographic, access to international markets, etc). Some refineries may therefore experience hardship while others can actually benefit from the RFS program in net. Second, while there is evidence of pass-through of RIN prices, especially to E10 in certain markets, there is not sufficient evidence to suggest that *all* RFS compliance costs are passed-through to prices. For example, research has not found complete pass-through for E85. Finally, even if there is 100% pass-through of all RIN prices to final product prices, consumers will respond to the increased price by decreasing the *quantity demanded* for fuels. This reduction in demand will negatively impact the refining sector. Both the effect of equilibrium price and quantity of fuels sold should be considered when assessing the effects of the policy.

[3]Latin for *everything else held constant.*

1 Introduction

The Renewable Fuel Standard (RFS) requires U.S. transportation fuels to contain a minimum volume of fuel that is considered renewable. The RFS was established by the Energy Policy Act of 2005 (P.L. 109-58; EPAct05) and was expanded in 2007 by the Energy Independence and Security Act (P.L. 110-140; EISA) (CRS, 2020). The program was designed to lessen the United States' reliance on imported oil and reduce greenhouse gas emissions from the sector (EPA, 2021c).

Biofuels are blended with gasoline and diesel to comply with the RFS. Each "obligated party"[4] applies the U.S. Environmental Protection Agency's—hereafter simply referred to as "EPA"—annual percentage standard to their own production or importation of gasoline and diesel fuel to calculate their individual renewable volume obligation (RVO or RFS obligation) for each type of renewable fuel.[5] The firm separates Renewable Identification Numbers (RINs) corresponding to the quantity of biofuel blended. Market participants are allowed to trade RINs, and obligated parties must acquire, either by blending themselves or purchasing RINs from the market, and then ultimately retire RINs for compliance (EPA, 2021d).

The EPA administers the RFS and is responsible for several tasks including evaluating which renewable fuels are eligible for the program, establishing the amount of renewable fuel that will be required, and monitoring compliance with the RFS through RINs, among others (CRS, 2020).

One of EPA's responsibilities in administering the RFS is to determine if any refineries qualify for the small refinery exemption (SRE) in consultation with the Secretary of Energy (EPA, 2021a). The CAA provides that small refineries may petition EPA for an exemption from the RFS obligation if the RFS creates a disproportionate economic hardship (DEH) for the small refinery. For perspective, there are currently 124 operating refineries in the U.S. today (EIA, 2021)[6] with a total operating capacity of 17.7 million

[4]Obligated parties include refineries and importers of gasoline and diesel fuel.

[5]See p. 8-9 of EPA (2021b) for an overview of the annual percentage standard and firm-specific obligation.

[6]Includes only operating refineries. Accurate as of January 1, 2021.

barrels per day (EIA, 2021).[7] In 2020, there were 28 small refineries with petitions for the SRE.[8]

In December of 2021, the EPA published its *Notice to Comment on Proposed Denial of Petitions for Small Refinery Exemptions.* Alongside this notice, EPA published a document titled *Proposed RFS Small Refinery Exemption Decision* (EPA, 2021b). With this notice, EPA stated that it is seeking comment on a proposal to establish a change to its statutory interpretation of the Clean Air Act (CAA) small refineries provisions. According to EPA, this change in interpretation would result in the denial of 65 pending petitions[9] for small refineries to seek SREs from the RFS program. More specifically, EPA is proposing that the small refineries with pending petitions have failed to demonstrate the DEH that the CAA requires for EPA to grant such exemptions.

The conclusions relied upon by EPA are (EPA, 2021b) *(underline added for emphasis)*:

1. Regardless of the mechanism by which small refineries and other obligated parties comply with their RFS obligations, the RFS compliance costs are the same for all obligated parties and thus no party bears RFS compliance costs that are disproportionate relative to others' costs.
2. Obligated parties, including small refineries, recover their compliance costs through the market price they receive when they sell their fuel products and thus do not bear a hardship created by compliance with the RFS program.
3. With no disproportionality and no economic hardship, there can be no disproportionate economic hardship pursuant to the statute.

[7]Includes only operating refineries. Accurate as of January 1, 2021.

[8]The names of the refineries that have applied for this exemption are not available to the public. Although, assuming that each of these refineries has a 75,000 bpd capacity (the threshold for a small refinery), these would make up at most 12% of U.S. refining capacity. The actual share is likely lower.

[9]Note that these petitions span the compliance years 2016 to 2021. A single refinery can have petitions in multiple years. See page 6 of EPA (2021b).

Hereafter, these will be referenced as Claim 1, Claim 2, and Claim 3.

In this report, we provide an opinion on the plausibility of Claim 1 and Claim 2. Specifically, two questions will be considered. First *are RFS compliance costs plausibly the same for all parties?* Second, *is it plausible that small refineries recover their compliance costs through the market price they receive when they sell their fuel products to the market?* We view Claim 3 as a legal question. We therefore leave Claim 3 to be evaluated by legal experts perhaps guided by the answers to the questions above. Further, we will not address whether specific refineries should qualify for this DEH exemption. Instead, this report will narrowly focus on these two questions that are central to EPA's proposed denial of SRE petitions. This opinion will be informed by economic theory and corroborated with a review of prior literature, analysis of publicly available data, and the authors' general knowledge of liquid fuel markets.

There are many points made and specific data analyzed in EPA (2021b). Given the inherent quick timeline associated with the comment period, we focus on providing a broad assessment of these major claims as opposed to analyzing particular details or ancillary points in EPA (2021b). Additional analysis of other particular details or ancillary points would of course be possible with more time. The omission of a discussion on any specific claim made by EPA should not be interpreted as either agreeing or disagreeing.

Finally, we make no claims regarding whether the particular conditions and assumptions required for Claim 1 and/or Claim 2 to be valid for any one refinery in particular, or any specific refinery at all within the industry. We instead highlight whether these claims are plausible broadly. The burden of providing evidence of DEH for a specific refinery is on the refinery itself.

2 Economic Theory

Neoclassical economic theory is based on two related problems, the maximization of profits by firms and the maximization of utility (wellbeing) by individuals. It is the simultaneous solution of these two problems that yields an economic equilibrium where prices and quantities are observed. Through-

out the discussion, notation will be largely borrowed from Varian (2009)[10], but the general economic theory can be found in any modern micro-economic theory text.[11] Discussion of economic principles will be generally based on Krugman and Wells (2014), but again similar concepts can be found in any undergraduate introductory economics text book.

The purpose of this section is not to teach these principles. Instead the purpose is to provide a refresher for readers with prior undergraduate economics training, reference relevant texts, and discuss how these core economic principles apply to the questions at hand.

2.1 Supply Curve

The goal of a firm is to *maximize profits* subject to market prices and technological constraints. A firm's profit (π_i) can be written as:

$$\pi_i = r_i - c_i \tag{1}$$

Individual firms are indexed by i. r_i is the firm's revenue, and c_i is the firm's costs. Intuitively, Equation (1) simply states that a firm's profits are equal to its revenues less its costs.

Equation (1) can be expanded with additional details as follows:

$$\pi_i = \underbrace{(p_i \times q_i)}_{r_i} - \underbrace{\left[F_i + (w_i \times x_i)\right]}_{c_i} \tag{2}$$

The firm's revenues (r_i) are equal to the price that the firm sells its output (p_i) times the quantity of output it produces (q_i). The firm's costs (c_i) can be divided into two components, fixed and variable costs. Fixed costs (F_i) are costs that do not vary with the amount of output produced and are incurred by the firm even when they choose to produce nothing

[10]Modifications to notation will be utilized where appropriate for clarity and consistency within this context.

[11]The modern neoclassical economic framework, which is the standard economics curriculum taught in universities, can be traced back to Samuelson (1947), written by the winner of the Nobel Memorial Prize in Economic Sciences in 1970.

(e.g., the cost of constructing a building). It is usually assumed that firms cannot change their fixed costs in the short run. The second component, collectively referred to as variable costs ($w_i \times x_i$), is equal to the price of inputs (w_i) times the amount of inputs purchased (x_i). Variable costs, as the name suggests, change with the amount of output produced. In this simplistic example, the firm sells only one output (q) and purchases only one input (x), but this theory is generally applied to include multiple input and outputs. In the context of refining, three logical outputs are gasoline, jet fuel, and diesel fuel. Each of these outputs is produced in different quantities and sold at different prices. Two logical inputs are hydrocarbon feedstocks and labor.

Next, economic theory introduces a *production function* that describes the process through which inputs (x) are transformed into outputs (q). Equation (3) can be written to include the firm's production function ($q_i(x_i)$) as follows:

$$\pi_i = (p_i \times \underbrace{q_i(x_i)}_{q_i}) - \Big[F_i + (w_i \times x_i)\Big] \tag{3}$$

where the level of output produced by the firm (q_i) is a function of the inputs used (x_i). For example, a refinery can produce some quantity of outputs (i.e. gallons of gasoline, diesel, and jet fuel) for a given amount of inputs (i.e. hydrocarbon feedstocks such as crude oil). This production function is influenced by physical and technological constraints, as well as a specific refinery's configuration. Note that each refinery's production function is unique, as refineries have different configurations and therefore are able to process different varieties of crude oil, have different ratios of outputs (i.e. different shares of gasoline, diesel, jet fuel, etc), use different amounts of energy to run, among other factors (EIA, 2015).

A firm will choose the amount of output it produces (q_i) such that profits are maximized. Economic theory suggests that, in a purely competitive market, the firm's solution to this maximization problem results in a willingness to supply an additional unit of output (q_i) to the market as long as the extra revenue (Δr_i) gained by one more unit of output is greater than

the extra cost (Δc_i) of producing that unit. More rigorously, a firm will produce an additional unit of output as long as $\Delta r_i \geq \Delta c_i$. Under pure competition, the firm's supply curve is then equivalent to its *marginal* cost curve.[12]

Shutdown Condition The discussion above assumes that it is profitable to produce *something*; however, it could be that the most profitable option for the firm is to produce zero. If the profits from producing zero output and paying only the firm's fixed costs exceed the profits of producing where price equals marginal cost (the solution outlined above), the firm will choose to produce nothing. In this instance, the firm will not be profitable.

Another scenario is that a firm will choose to produce some amount of output up until the point where marginal revenues equal marginal costs, but that the revenues received are not large enough to pay the firm's total costs. In this instance, a firm might choose to produce some level of output in the short run, but will not be profitable and will make the economic decision to exit the market in the long run.

In both cases, although firms might choose to operate at a negative profit in the short run, in the long run the firm will choose to exit the market. It is possible for a policy, such as a RFS, to impact a firm's choice to continue to operate or shut down.

2.2 Demand Curve

The goal of an individual is to *maximize utility.* Philosophers and economists use the term "utility" to describe an individual's overall wellbeing, or happiness. In the same way that firms face tradeoffs to maximize profits as discussed in Section 2.1, people make tradeoffs in order to maximize utility. Individuals decide how much time to spend working (thus earning income) and how much time to spend on leisure. Individuals observe market prices of goods and services and a wage rate based on their skill level. The utility maximization problem is used to derive the individual's *demand curve.*

[12]See Chapters 19-22 of Varian (2009) for more information on profit maximization and supply.

Economic theory suggests that an individual is willing to purchase an additional unit from the market if the marginal benefit they receive from that unit is greater than or equal to the cost of purchasing that unit. Thus, the individual's demand curve is equivalent to their marginal benefit curve. As the current problem being addressed is largely focused on producers, the demand curve is considered fixed throughout the discussion.[13]

2.3 Market Equilibrium

In a competitive market with many buyers and sellers, the *market supply* curve (S) can be written as the aggregation of each firm's individual supply curve ($\sum_i s_i$).[14] Similarly, the *market demand* curve (D) can be written as the aggregation of each consumer's demand curve ($\sum_i d_i$).

This economic theory is summarized in Figure 1. P represents the market price and Q represents the total quantity of the good that is supplied to, and purchased from, the market.

S represents the market supply curve, which is equivalent to the summation of the marginal cost curves of all firms (MC). Notice that the market supply curve shows a positive relationship between the market price and the amount firms are willing to supply. Intuitively, as the price increases, firms are willing to supply more of the good or service.

D represents the market demand curve, which is equivalent to the summation of the marginal benefit of each consumer in the market from consuming an additional unit of this good or service. Notice that the market demand curve shows a negative relationship between the market price and the amount consumers are willing to purchase.

The intersection of the market supply and market demand curves creates the market equilibrium. P^* is the market equilibrium price that is observed and Q^* is the equilibrium quantity that will be produced (and consumed) at this price. Deviations from this equilibrium generate a mismatch in the

[13] See Chapters 4-6 of Varian (2009) for more information on utility maximization and consumer demand.

[14] More specifically, the market supply curve is the horizontal summation of the individual supply curves.

market between the quantity supplied and demanded.

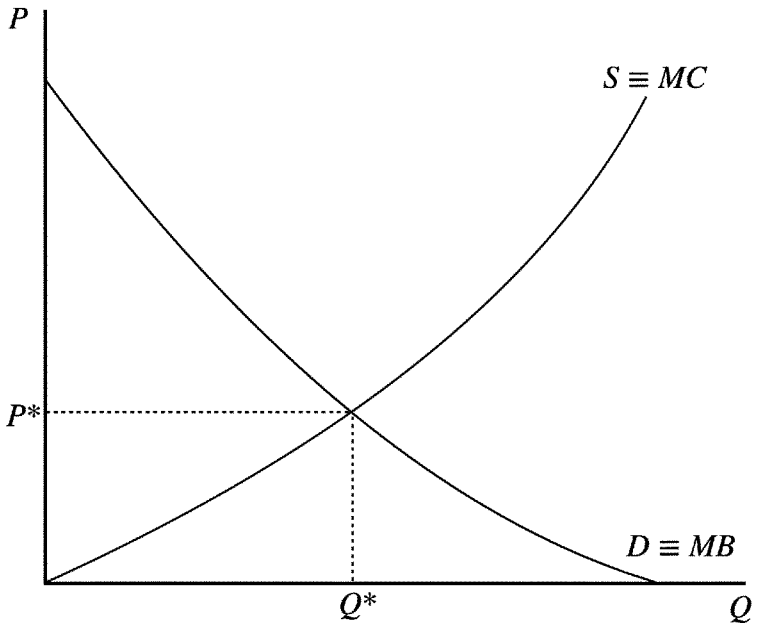


Figure 1: Market Equilibrium

Source: Authors' sketch

Unless stated otherwise, both individuals' demand curves and the market demand curve will implicitly be fixed. Any change in the equilibrium price or quantity of liquid fuels in the discussion will come from changes to the firms' cost curves and profit maximization problems in conjunction with movements along the demand curve.

2.4 Producer and Consumer Surplus

One way to measure the welfare of producers and consumers is through the concepts of *producer surplus (PS)* and *consumer surplus (CS)*.

Consumer Surplus (CS) CS is the difference between the price a consumer pays for a good or service and the consumer's willingness to pay for the good or service. Willingness to pay is defined as the maximum price at which the consumer would pay for a good or service. In other words, the consumer would choose to not purchase the good or service if the price is greater than the consumer's willingness to pay. The willingness to pay is represented by the consumer's demand curve.[15] The price the consumer faces is the market equilibrium price (P^*). Thus, an individual's consumer surplus is the difference between their willingness to pay and P^* while the aggregate market consumer surplus is the summation of all individuals' consumer surplus. The total consumer surplus is represented by the triangular area above the equilibrium price and below the market demand curve shown in Figure 2.

Producer Surplus (PS) Just as some buyers of a good would have been willing to pay more than the market price they face, some sellers of a good would have been willing to sell it for less than the price they actually receive. As a corollary to CS, PS is the difference between the price that a firm is willing to supply a good or service to market and the price it actually receives for the good or service. The price that the firm is willing and able to supply to the market is represented by the firm's supply curve. The price the firm receives for the good or service is the market equilibrium price (P^*). Thus, the aggregate market producer surplus is represented by the triangular area below the market equilibrium price down to the market supply curve shown in Figure 2.[16]

Total Surplus (TS) Total surplus is simply the sum of producer and consumer surplus. It can be written mathematically as:

$$TS = PS + CS \tag{4}$$

[15]See Module 11 of Krugman and Wells (2014) for more information regarding the consumer's demand curve and consumer surplus.

[16]Again, see Module 11 of Krugman and Wells (2014) for more information regarding the firm's supply curve, costs and producer surplus.

Although we do not include a detailed discussion here, it can be shown that once the market is in equilibrium, there is no way to increase total surplus. In other words, the equilibrium price and quantity that occurs where the supply and demand curves intersect maximize welfare (measured by total surplus), and any other outcome results in a reduction in total surplus.[17]

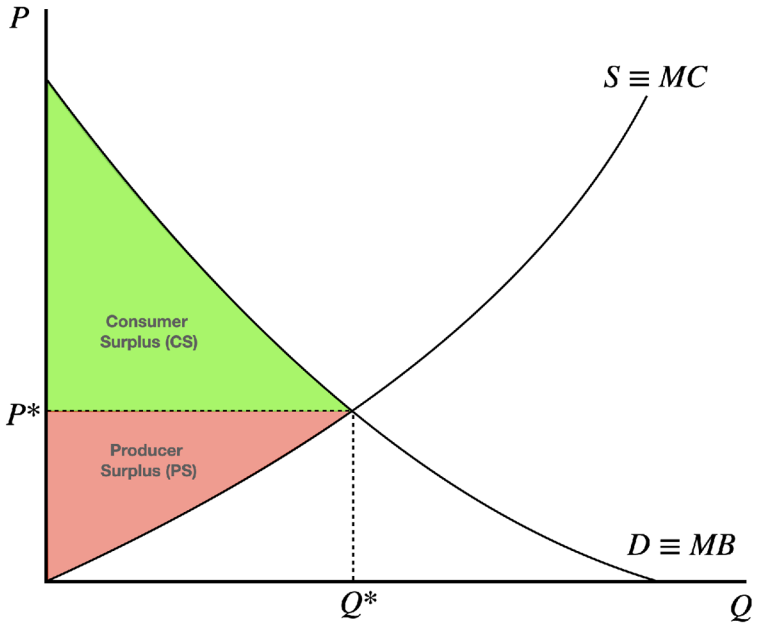


Figure 2: Consumer and Producer Surplus

Source: Authors' sketch

The simplified illustration of the theory presented in Figure 2 relies on several assumptions. Most notably, this basic model does not incorporate market failures, which may justify government intervention in the market and lead to situations where movements from the market equilibrium may improve the welfare of society. There are many examples, such as

[17]See Module 12 of Krugman and Wells (2014) for more information on total surplus.

the presence of externalities[18], concerns about fairness[19], presence of market power[20], among others that can be incorporated into this basic model. Indeed, the transportation sector is a large contributor of greenhouse gas emissions (i.e., a pollution externality). One of the stated goals of the RFS program is to reduce these emissions. Specifically, the transportation sector accounted for 29% of total GHG emissions in the U.S. in 2019, making the sector the largest contributor of such emissions.[21] The conceptual supply and demand framework presented above provides a useful framework to understand a policy's implications for consumers and producers, but we make no claim as to the overall net costs/benefits of the policy, as this is clearly outside of the scope of this specific EPA proposed decision.

2.5 Incorporating RFS into Economic Theory

We next consider how the prior-mentioned economic theory suggests the RFS will impact the market for liquid fuels. Firms can meet the requirements of the RFS in two ways. The first option is that the firm can choose to purchase renewable fuels and blend a sufficient amount into its fuel to meet the RFS obligation. If the firm blends more than its required amount, the firm can sell excess RIN credits to the market. The second option is that a firm can purchase RIN credits from firms that have excess RIN credits. In this instance, money will be shifted away from buyers of RINs to sellers. In effect, the RFS imposes a tax on each gallon of nonrenewable fuel and a subsidy on renewable fuels (Knittel et al., 2017). The contemporaneous price of RINs, and expectations about the future price of RINs, will influence a firm's decision to produce renewable fuels or purchase RINs from the market.

Recall from Section 2.1, that under pure competition, a firm's supply curve is equivalent to its marginal cost curve. Further recall from Section 2.3 that the market supply curve can be written as the summation of each firm's

[18] E.g. see Chapter 34 of Varian (2009).
[19] E.g. see Module 12 of Krugman and Wells (2014).
[20] E.g. see Chapters 24, 25, and 27 of Varian (2009).
[21] United States Environmental Protection Agency website. Greenhouse Gas Emissions. Sources of Greenhouse Gas emissions. Accessed Jan 12, 2022.

individual supply curves. Thus, because the RFS represents an increase in the marketwide marginal cost of supplying fuel to the market, it can be modeled as the vertical shift in the market supply curve from S to S' illustrated in Figure 3. Economic theory suggests that the vertical shift in the supply curve will be equal to the RIN price.[22]

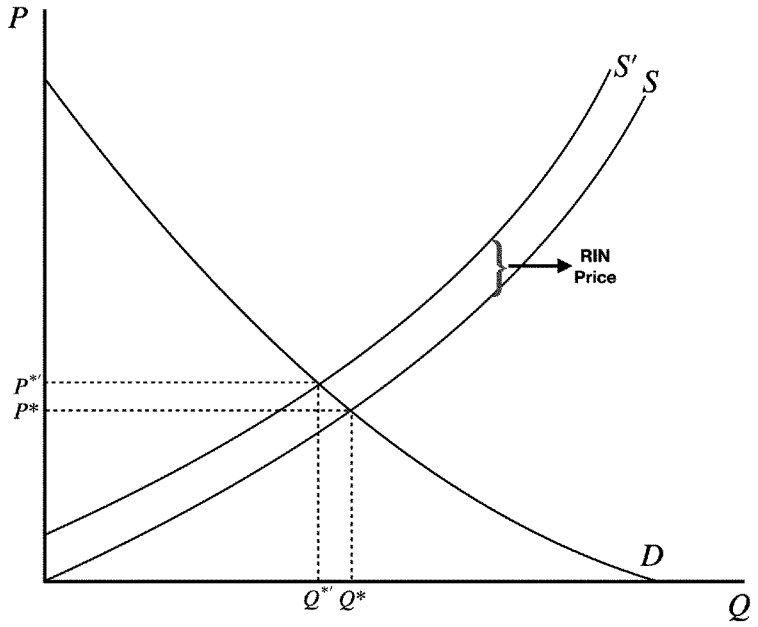


Figure 3: Market Equilibrium with Renewable Fuel Standard

Source: Authors sketch

Economic theory makes two predictions about the effect of the RFS on the market for liquid fuels. First, the price of fuels increases from P^* to $P^{*'}$. Consistent with EPA's claims, economic theory does predict that consumers will have to pay a higher price, and that producers will receive

[22]Tradable permits and taxes are both, in theory, capable of achieving the least-cost solution to increasing biofuel usage. See Chapter 5 of Hanley et al. (2007) for a discussion of practical tradeoffs.

a higher price for the liquid fuels sold. In addition, the quantity of fuel produced (and therefore consumed) will be reduced from Q^* to $Q^{*'}$. The aggregate net effect of the policy on total producer surplus will therefore be influenced by three factors:

1. Firms in aggregate will incur additional costs to comply with the policy. This will be either additional costs to purchase and then blend renewable feedstocks or the cost of purchasing RINs from the market to meet the standard. Although some firms might sell RINs for more than their increased costs, marketwide costs will increase in aggregate.[23] *Ceteris paribus*, this will reduce total industry surplus of firms.

2. Firms will receive a higher price for the liquid fuels sold. *Ceteris paribus*, this will increase total industry surplus of firms.

3. Firms in aggregate will sell less fuel. *Ceteris paribus*, this will reduce total industry surplus of firms. Reductions in fuels supplied will be borne by firms with high compliance costs.

Pass-through of taxes or input costs Pass-through of taxes or input costs into prices has been studied by economists in a number of contexts (Muehlegger and Sweeney, 2022). These concepts are so related, that economists have used cost pass-through to estimate the incidence of actual taxes (e.g., (Marion and Muehlegger, 2011; Fabra and Reguant, 2014)).

Input cost incidence is a measure of who incurs the burden of a change in input costs. Changes in input costs can come from changes in market conditions as well as government policies, such as taxes. Regardless of the source of the change in input costs, the *burden* of the cost increase cannot simply be determined by identifying the party that actually *incurs* the cost.[24] In practice, the burden of a cost increase is allocated between con-

[23]Note that if renewable fuels were less expensive to produce than fuel from crude oil, then all firms would produce renewable fuels regardless of the RFS, and RIN values would trade at zero.

[24]For example, see Module 15 of Krugman and Wells (2014) that states *"the burden of a tax cannot be determined by looking at who writes the check to the government."*

sumers and producers as a function of the price elasticity of supply and the price elasticity of demand as well as other factors that might be specific to the setting.

The consumer and producer surpluses with the RFS are illustrated in Figure 4. Comparison to Figure 2 yields two observations.[25]

1. Consumer surplus from consumption of the private good is reduced due to the RFS. Consumers will pay a higher price for liquid fuels. Further, there will be less liquid fuels sold to consumers due to the higher price.

2. The net effect on producer surplus is negative. Although in aggregate, producers will sell fuels at a higher price, there will be less fuel sold. Further, producers in aggregate will incur higher costs due to RFS compliance. The extent to which producers pass-through the cost of RFS compliance onto consumers is an empirical question.

3. A market subsidy for biofuels is introduced. Note that this biofuel subsidy can be shared across the value chain, from biofuel producers, transporters, blenders, and perhaps even gasoline stations.[26] To the extent that individual refineries are in the blending business, they may capture some of this subsidy. Therefore, the net effect of this policy on the refinery industry producer surplus as a whole is ambiguous.

In this setting specifically, the incidence of the policy will depend on the elasticity of (i) gasoline and diesel fuel supply, (ii) renewable fuel supply

[25]Though it is beyond the scope of this analysis, total surplus is also shown to be reduced. This reduction is referred to as "deadweight loss"; however, it is important to note that for simplicity, this illustrative example ignores market failures that the RFS may address. The authors therefore make no claim as to the actual welfare effects of the RFS.

[26]For example, Casey's General Store (Nasdaq ticker "CASY") stated in their Q1 2022 Earnings Call that "the company took advantage of a favorable renewable fuel credit environment and sold $18.7 million in RINS" and that "the fuel team has done a tremendous job balancing fuel volume and margin to optimize the profitability of this category." Note that we take no position on whether CASY's profits were actually positively impacted by the RFS in net.

and (iii) fuel demand (Yeh et al., 2016).[27] Economic theory suggests that the more inelastic, or less price sensitive, of the two groups (producers or consumers) will bear more of the policy's costs. Because consumer demand for fuel is inelastic, especially in the short run (Brons et al., 2008; Gillingham et al., 2015), the lion's share of the costs of the RFS are likely to be passed-through to consumers, although this is an empirical question that will be addressed in Section 3.2.

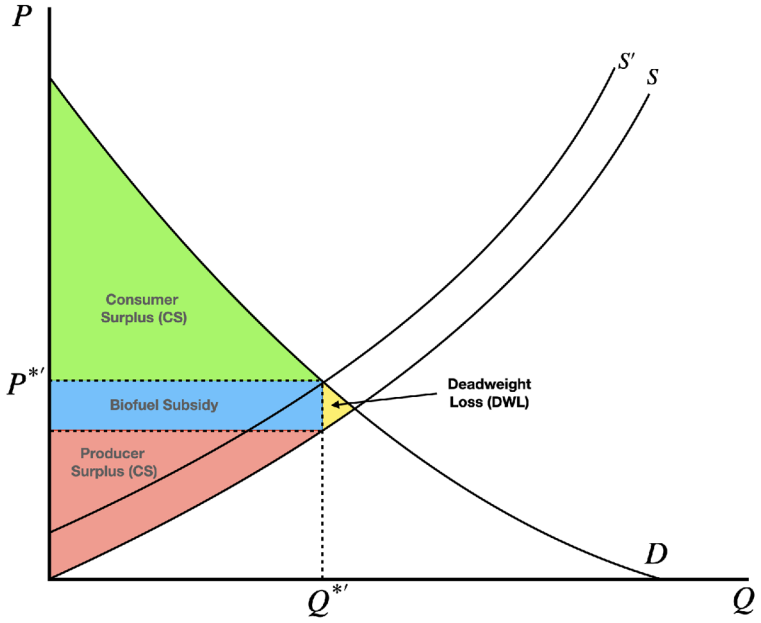


Figure 4: Consumer and Producer Surplus with Renewable Fuel Standard

Source: Authors' sketch

[27] In this specific example, the incidence can also depend on the specifics of the supply chain, i.e. ethanol production, transportation, blending, gasoline sales, etc.

2.6 Tradable Permits

The RFS is an example of a tradable permits program. Tradable permit programs for the purpose of regulating environmental externalities have been studied in the academic literature for decades (Hanley et al., 2007; Dales, 1968; Tietenberg, 2006; Stavins, 2003). Empirical analysis of specific tradable permit programs, both existing and proposed, are also ubiquitous across the literature (Young and Bistline, 2018; Bushnell et al., 2017; Upton and Snyder, 2017; Paltsev et al., 2008; Stavins, 1998). If functioning properly, tradable permit programs are designed to achieve policymakers' desired outcome—in this instance the desired level of biofuels integration into the market—in the least-cost manner. Given the context, we will consider the example of the RFS in discussing tradable permit programs more broadly.

It is important to note, though, that the economic logic for tradable permit programs, in lieu of simply requiring some level of biofuel blending for each individual firm, is based in the assumption that the costs for each firm to comply with a regulation differs across firms. Firms with relatively high marginal compliance costs will be buyers of permits, while firms with low marginal costs of compliance will be sellers of these permits (or "credits" in this context).[28] The tradable permit program, if implemented successfully, will allow these firms to trade credits, thus achieving the least-cost incorporation of biofuels into the market. In this way, economists would describe a well-functioning tradable permit program as "efficient."

Importantly, the total financial burden of a tradable permit program, such as the RFS, to an individual firm will be influenced by both the cost to the specific firm to comply with the program as well as the transfer payments made between firms when permits are bought and sold. Although all firms will have the option to purchase credits from the market at the same price, some firms will be able to produce that credit for less than the credit price. For other firms, the cost to produce credits internally might exceed the permit price, in which case the firm will choose to purchase credits from the market. The marginal compliance cost of the aggregation of all firms

[28] See Section 5.3 of Hanley et al. (2007).

alongside the number of permits required will determine the permit price.[29]

In this specific context, some firms will be able to acquire RINs by blending renewable fuel (that they purchased or produced themselves) for a lower cost than the market RIN price. A tradable permit program, such as the RFS, allows for these firms to over comply by blending more than their requirement and therefore acquiring and selling excess RINs. For other firms, the cost to blend renewable fuel will be higher than the RIN price, and thus these firms will choose to purchase RINs from the over complying firms in lieu of blending. Transfer of RFS obligations is formally accomplished through the market for RINs. The RIN price will be determined by the interaction of buyers (firms with high blending cost) and sellers (over complying firms with low blending costs) in the market.

Stated another way, the fundamental economic rationale for implementing a tradable permit program in lieu of a simple requirement for each individual firm is *because the costs of compliance differ across firms.* Thus, EPA's claim that compliance costs are the same for each firm regardless of whether they blend to produce credits for compliance or purchase credits from the market is not grounded in the economic theory of tradable permits. On a related note, the concept that tradable permit programs (such as RFS), or fluctuations in credit prices (such as RINs), place a proportional burden on all market participants is also not grounded in the economic theory of tradable permit programs.

2.6.1 Tradable Permits Program Example

For clarity, we next present an example of a tradable permit program to illustrate how firms are impacted differently by a tradable permit program, even if that program achieves the least-cost compliance and results in a "Pareto efficient" outcome.[30]

[29]See Figure 5.4 of Hanley et al. (2007) showing the marginal compliance curve is equal to the sum of all individual firms' marginal compliance curves. Note that we use the term "marginal compliance curve" which is the corollary to "marginal abatement curve (MAC)" in Hanley et al. (2007)

[30]Economists refer to a "Pareto efficient" outcome as one in which no individual (or firm in this example) can be made better off without making at least one individual worse

Figure 5 depicts three firms: Firm A, Firm B, and Firm C. Due to the context of the RFS, the vertical axis represents the *Marginal Blending Cost*, denoted MBC, where MBC_A is Firm A's marginal blending cost, MBC_B is Firm B's, etc. While three firms are shown in this example, this concept generally applies to a case with many firms. Also for simplicity, this example includes one type of biofuel and one type of RIN.

To clarify semantics, blending costs include the cost of obtaining, transporting and blending the biofuel into the final product (E10, E85, biodiesel, etc). In other words, blending costs can be described as the entirety of extra costs needed to produce the renewable fuel blend in lieu of producing fuel without the RFS.

In this example, there is a positive relationship between marginal blending cost and quantity blended, as is the classic example presented in economics curriculums, although, we will show below that the overall conclusion is similar in the case in which marginal blending costs is constant for each firm up until some physical capacity constraint is met.

Referencing Figure 5, the RIN cost (in dollars per gallon) is shared by all firms. In other words, each firm has the option to purchase RINs at the market price shown. The RIN price is represented as a dashed horizontal line. Each firm also has a renewable volume obligation (RVO) that is set by the EPA. The RVO is represented by a vertical dashed line. In this example, all three firms produce the same quantity of fuels subject to the RVO, and therefore have the same obligation. In practice, firms of different sizes will have different obligations, and firms will, with some limitations, be able to adjust the volume of fuels sold to impact their RVO obligation. In this simplistic example, the RVO is fixed.

Focusing first on Firm A: This firm is able to blend its RVO at lower cost than the RIN price. Instead of purchasing RINs from the market to meet the RVO, Firm A will instead blend the renewable fuel and satisfy the obligation itself. Once Firm A meets its RVO obligations, the marginal cost of blending additional units is still below the RIN price (i.e. $MBC < RIN$). Firm A will therefore make the profit maximizing choice to increase the amount

off. See Section 1.9 of Varian (2009).

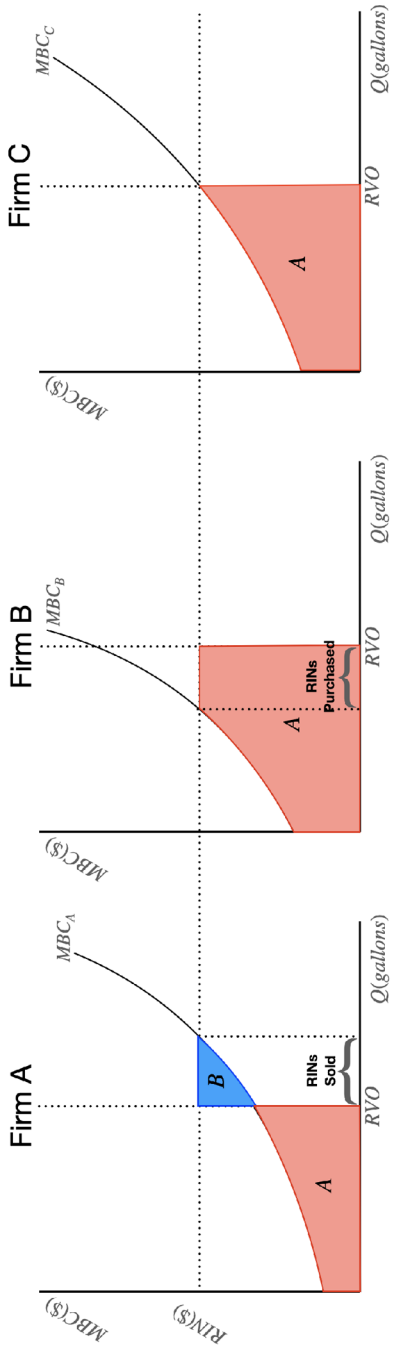


Figure 5: Marginal Blending Costs and Compliance

Source: Authors' sketch

of renewable fuel it blends up until the point where the marginal blending cost is exactly equal to the RIN price (i.e. $MBC = RIN$). At the point where blending one more gallon costs more than the revenues the firm would receive from selling the RIN, it will make the profit maximizing choice to not blend in the next gallon of renewable fuel.

In summary, Firm A will make the profit maximizing decision to satisfy its RVO by blending and then generate excess RINs, which it will sell to the market. Firm A's total compliance cost will be equal to the shaded area A less the revenues it receives in excess of blending costs for RINs sold to the market, shown in shaded area B.

Next, we focus on Firm B. Like Firm A, the marginal cost of purchasing RINs is higher than the blending cost up until some point. Unlike Firm A, Firm B will not blend its entire RVO. At the point where the marginal blending costs exceed the price of RINs, Firm B will make the profit-maximizing decision to purchase RINs from the market, in lieu of blending. Note that Firm B *could* choose to meet its RVO by blending, but the least-cost way to meet its obligation is a combination of blending and RIN purchasing. Both Firm A and Firm B are made better off by engaging in the trade of RINs.

In summary, Firm B makes the profit-maximizing decision to blend to achieve part of its RVO and also purchase RINs from the market to meet the residual RVO not met internally. Firm B's total compliance cost will be equal to the shaded area A. Comparison of Firm A and Firm B shows that the total compliance cost to Firm B is larger than the total compliance cost to Firm A.

Finally, focusing on Firm C, we see that, like Firm A, Firm C will also meet its RVO entirely by blending. Once the RVO has been reached, the marginal cost of blending additional gallons of biofuels will be higher than the RIN price. Firm C will therefore choose to meet its RVO exactly by generating RINs through blending and will not engage in the market for RINs. Their total compliance costs are again equal to the red shaded area A.

The main takeaway from Figure 5 is that although each firm has the option to purchase RINs from the market at the same price, each firm will

have different compliance costs. Thus, although the market for RINs might be considered "efficient" and allow for the least-cost compliance, individual firms are impacted differently by the policy.

RIN Price Change Next consider the effect of a change in RIN prices for these three firms by comparing Figure 5 and Appendix Figure A1.

In the event that the RIN price were to increase *ceteris paribus*, Firm A would be better off. This is because area A that represents the firm's compliance cost would remain unchanged, but area B that represents the producer surplus from the sale of RINs would get larger for two reasons. First, the difference between Firm A's marginal blending cost and the RIN price will increase for the RINs the firm is already selling to the market. Second, the firm will make the profit maximizing choice to now blend more biofuels up until the point where $MBC = RIN$. Firm A will now sell more RINs at a higher price. Thus, if RIN prices increase, *ceteris paribus*, Firm A will be better off.

Consider the effect of an increase in the price of RINs next for Firm B by again comparing Figure 5 and Appendix Figure A1. In this example, Firm B would be worse off for two reasons. First, Firm B will choose to blend more in lieu of purchasing RINs, but this blending will come at a higher cost than it's prior option to purchase RINs at the lower price. If the price of RINs were to increase sufficiently, Firm B might even decide to blend all of its RVO instead of purchasing RINs. Second, Firm B will still purchase some RINs from the market in this example, but at a higher price than before the RIN price increase. Thus, if RIN prices increase, *ceteris paribus*, Firm B will be worse off.

Finally, consider the effect of a RIN price increase for Firm C, *ceteris paribus*. Like Firm A, Firm C was already meeting its RVO internally through blending. When the price of RINs increases, Firm C will not incur any additional costs to meet its RVO, but Firm C will at that point make the profit-maximizing decision to blend more than its RVO and sell RINs up until the point where $MBC = RIN$. Firm C will increase its blending, generating excess RINs that it can then sell to the market for a profit. Thus,

if RIN prices increase, *ceteris paribus*, Firm C will be better off.

Note that in reality, RIN prices and firm specific marginal blending cost (MBC) curves will have some feedback (i.e. a change in marketwide MBC can cause a change in RIN prices); however, this simple example illustrates that changes in RIN prices can affect refineries differently.

Constant Marginal Blending Cost Curve Example The examples in Figure 5 and Appendix Figure A1 include specific assumptions about the marginal blending cost (MBC) for each refinery. Specifically, economists would describe the MBC curves as depicted in these figures as *monotonic* and *convex*. Perhaps a more simplistic representation is one in which the blending cost is the same for each unit, up until some threshold that represents a physical constraint such as the "blend wall" or some refinery specific constraints. An illustration is shown in Appendix Figure A2.

Notice that in Figure 5, each firm's marginal blending curve (MBC) is *upward sloping*;[31] each additional unit of blending was more expensive than the prior unit. In contrast, the blending cost *is the same* for each unit blended (until the threshold is met) in the example shown in Appendix Figure A2.

Focusing now on the example shown in Appedix Figure A2, Firm A will blend sufficient quantities to meet its RVO. At that point, Firm A will make the profit maximizing decision to exceed its RVO by blending additional volumes because the value of the RIN the firm sells to the market exceeds the marginal blending cost (i.e. $RIN > MBC$). It will do so until it reaches its constraint where it can no longer blend.[32] Firm A's compliance costs are again shaded area A less shaded area B.

Firm B in this example has marginal blending costs that are above the price of RINs ($MBC > RIN$). Firm B will therefore make the profit maximizing decision to purchase all RINs from the market. Note that Firm B *could* choose to blend and generate the RINs internally, but the tradable

[31] In math, has a positive slope.

[32] Another way to state this is that the marginal cost of blending increases rapidly once the blend wall or technological constraint is met.

permit program allows the firm to instead purchase RINs from the market at a lower cost. Although this trade would be described as efficient by economists, Firm B's compliance costs (shaded area A) are larger than the compliance costs of Firm A.

Firm C's blending cost is exactly equal to the RIN price. Firm C will be indifferent between blending to meet its RVO and purchasing RINs from the market. Regardless of which option Firm C chooses (blending or purchasing RINs), its compliance costs will be the same as Firm B, i.e. the shaded area A.

Notably, the option to purchase RINs from the market puts an implicit cap on the total compliance costs that is equal to the RVO times the RIN price. But again in this example, the RIN market does not ensure that compliance costs are the same for all obligated parties.

The main takeaway from comparison of Figures 5 and Appendix A2 is that, regardless of the assumptions made about the shape of the marginal blending cost curves, as long as different firms have different MBC curves, the compliance costs of individual firms will be different. This is true even though each firm has the option to purchase RINs from the market at the same price.

2.7 Conclusions Reached from Economic Theory

In Section 2, economic theory has been presented and applied to the market for liquid fuels to assess the effects of a RFS on consumers and producers. We conclude by assessing what economic theory predicts regarding EPA's two claims.

Claim 1 Recall that Claim 1 by the EPA was that the RFS compliance costs are the same for all obligated parties. As discussed in Section 2.1, each individual firm can experience differences in input prices, output prices, as well as cost curves. As discussed in Section 2.3, the market supply curve is the aggregation of each individual supply curve.[33] Thus, economic theory

[33]Again, the aggregation is the horizontal summation of the individual supply curves.

does not require that each firm's supply curve be identical. Nor does economic theory require that the effect of a tradable permits program, such as an RFS, or fluctuations in permit prices (such as RINs) will be the same for all parties. An illustrative example under different assumptions about individual firms' costs of blending is presented in Section 2.6 to illustrate this point.

As will be discussed in Section 3.1, in practice it is implausible that each refinery has the identical marginal blending costs in the context of the refining industry. While economic theory does not rule out the possibility that the supply curves and marginal blending cost curves of every firm are identical, this is not an intuitive or required assumption of standard economic models. In fact, one of the fundamental purposes of tradable permits, such as an RFS program, in lieu of a simple requirement for each individual firm, is based in the assumption that the costs of compliance differ across firms.

Claim 2 Recall that Claim 2 by the EPA was that obligated parties recover their compliance costs through the market price they receive, and thus do not bear a hardship created by compliance with the RFS program. Economic theory predicts that compliance with the RFS will lead to higher costs for consumers.[34] The effect of the RFS program on market-wide refinery profits, however, will be determined by three factors: (1) the compliance cost incurred by the refineries; (2) the increase in price received for liquid fuels; and (3) the reduction in total liquid fuels sold.

Again, while economic theory does not rule out the possibility that the compliance costs are fully passed onto consumers, this outcome depends on the relative elasticities of supply and demand in the market. Therefore, the extent to which refineries are able to pass-through the cost of compliance (either through production or purchasing of RINs) to customers is ultimately an empirical question that will be addressed in the subsequent sections of this report.

[34]In this context, we refer to "consumers" are the final users of the fuel.

3 Empirical Evidence of Theoretical Predictions

We next evaluate how the empirical evidence and existing literature support the plausibility of Claims 1 and 2 made by the EPA.

3.1 EPA Claim 1: RFS compliance costs are the same for all obligated parties

The executive summary of EPA (2021b) contains the following quote:

> *Regardless of the mechanism by which small refineries and other obligated parties comply with their RFS obligations, the RFS compliance costs are the same for all obligated parties and thus no party bears RFS compliance costs that are disproportionate relative to others' costs.*[35]

In this section, we will assess the plausibility of this claim utilizing the economic theory presented in Section 2 alongside results of empirical research.

Recall equation 3 above that is reproduced here:

$$\pi_i = (p_i \times \underbrace{q_i(x_i)}_{q_i}) - \Big[F_i + (w_i \times x_i)\Big] \tag{5}$$

where π_i is firm i's profits. p_i is the price firm i receives for its output, and q_i is the quantity of output sold. w_i is the price of the inputs the firm purchases and x_i is the quantity of inputs the firm purchases. Each of these factors can impact the firm's marginal blending costs described in Section 2.6.

We will next conduct a review of the empirical literature to document the extent to which these factors might differ across refineries. Further, the effect of the introduction of the RFS, or changes in the market prices of RINs, can impact each firm differently based on these factors. This can be shown by delving briefly into each factor.

[35] Underline added for emphasis.

Output Price (p_i) The price for which a refinery sells its outputs will vary for a multitude of reasons. Refineries are located in different geographic locations, thus selling into different markets. While it is theoretically possible for a refinery to transport its fuel to any market in the country (or world), this ability varies across refineries due to differences in access to refined product pipelines and other modes of transportation. Transportation costs limit the ability of refiners to economically compete in geographically distant markets. Further, some refineries have access to international markets via export, while others do not.

In addition to a varying ability to economically compete in geographically distant markets, the price of fuels varies greatly across regions. Some of the difference is in part determined by the transportation costs mentioned above, but other factors are also important. Environmental regulations like Reformulated Gasoline and Reid Vapor Pressure regulations lead to variation in prices at a very local level (Brown et al., 2008; Chakravorty et al., 2008; Nehiba, 2022).[36] Gasoline and diesel taxes also vary considerably across space, with the gas tax ranging from under \$0.10/gallon to over \$0.57/gallon.[37] These fuel taxes have been shown to have varying levels of pass-through to drivers in some circumstances, suggesting producers and consumers share their burden to some extent (Marion and Muehlegger, 2011; Kopczuk et al., 2016). Further, the rate of this pass-through has been shown to depend on local market structures and proximity to jurisdictional boundaries (i.e., distance to a region with a different fuel tax) (Hurtado, 2019; Stolper, 2021). Other regional transportation policies are likely to affect the market and thus fuel prices. In addition, it is possible for the demand for renewable fuels to vary across regions.

As will be discussed in more detail in Section 3.2, RIN price pass-through to wholesale and retail prices has also been shown to vary across products (i.e. E10 and E85 (Knittel et al., 2017; Li and Stock, 2019)) and across

[36]These regulations are often levied at the county level, but can sometimes be applied to even smaller geographies.

[37]U.S. Department of Transportation. Federal Highway Administration. Policy and Governmental Affairs. Office of Highway Policy Information. Monthly Motor Fuel Reported by States. Tax Rates on Motor Fuels. Cents Per Gallon.

geographic locations (i.e. different regions of the country (Burkhardt, 2019) and urban versus rural areas (Li and Stock, 2019)). Burkhardt (2019) also finds that RIN cost increases are associated with higher jet fuel production and lower jet fuel prices, thus impacting the relative price of outputs.

Thus, the effect of the RFS, and fluctuations in RIN prices, on the price of the final output likely impacts individual refineries differently.

Production function ($q_i(x_i)$) Each refinery has different processing units which make up its configuration. Processing units include: atmospheric distillation, coker, hydrocracker, thermal cracker, alkylation, reformer, vacuum distillation, and many other types of units (Olsen, 2014). While the goal of this report is not to outline the refining process, suffice it to say the types, quantity, and capabilities of units at refineries are varied. Each firm's production function is therefore different due to the availability of capital. In other words, the quantity and share of outputs q_i could be different for each refinery even if they were provided identical inputs x_i.

Refineries do have some ability to change the outputs they produce in the short run by shifting their operations. For example, the EIA noted that downstream units associated with gasoline production, like catalytic crackers, were operated at a lower intensity than other downstream units in response to the drop in demand for gasoline at the start of the COVID-19 pandemic.[38] Changes in other inputs (e.g., feedstocks discussed below) can also lead to changes in output shares. These capabilities of course have physical limitations, but they do highlight the potential for some refineries to "avoid" the RFS by changing outputs to those that are not covered by the standard. An individual firm's ability to do this will depend on that specific refinery's production function.

In the case where some firms produce multiple products that are differentially affected by a policy, it is possible for the policy to have distributional consequences due to firms' disproportionate ability to reoptimize outputs when RIN prices change (Lesser et al., 1997). As previously mentioned,

[38] U.S. Energy Information Administration. Today In Energy. August 28, 2020. *Changing demand for petroleum products has led to operational changes at U.S. refineries.*

Burkhardt (2019) finds that RIN cost increases are associated with higher jet fuel production, providing empirical evidence that firms substitute between outputs in response to the program.

Specifically, EPA claims that the "RFS program places a proportional burden on all obligated parties based on their gasoline and diesel fuel production volume." Although it is true that each party will have the same RIN requirement based on their gasoline and diesel fuel production volume, differences in the firms' production functions and the ability to substitute between RFS regulated outputs and non-RFS regulated outputs suggest that the burden of the RFS program, and fluctuations in RIN prices, will disproportionately affect parties based on, in part, their production function that is relatively fixed in the short run. Although firms have the ability to make some changes to their production functions in the long run, this requires firms incur costs in the short run with the (hopeful) payout being influenced by future market conditions and the price of RINs.

All of these factors considered, the effect of an RFS on an individual refinery is influenced by the specific production function of that refinery, and the production function of the larger chemical complex that some refineries are integrated into.

Input Quantities (x_i) The main input of refineries is of course crude oil, but there can be significant variation in crude oil that impacts the refining process and the outputs produced. Crude oil is traditionally categorized along two dimensions, density and sulfur content.[39] Density is measured using the API gravity index with higher values indicating lower density (lighter) oil. Lighter crude oil tends to be higher in value because refineries can produce high-value products (e.g., gasoline, diesel, or jet fuel) with simple distillation. Heavy crude requires additional and expensive refining to yield the same high-value outputs as lighter crude oil and is therefore more generally associated with creating feedstock for petrochemicals and plastics or for road surfacing.

[39]U.S. Energy Information Administration. Oil and petroleum products explained. Refining crude oil. Inputs and Outputs. Last updated: October 15, 2021.

High-sulfur crude oil, often called "sour" crude, has a sulfur content above 0.5% by weight. Sour crude requires more impurities to be removed from it throughout the refining process than low-sulfur or "sweet" crude. Thus, the type of crude oil a refinery uses as an input can determine what share of its output is high-value light products like gasoline or diesel fuel. Given the variation in refining requirements to create outputs from different types of crude, a refinery's configuration (i.e. its production function as discussed in the prior section) will play a role in its input decisions. Thus, inputs of a refinery are directly related to the refinery's production function. This is another channel through which the RFS requirement, and fluctuations in RIN prices, can impact individual refineries differently.

Input Prices (w_i) As discussed above, refineries can purchase a variety of different crude oils. Their decisions are determined both by the availability of crude oil variants and their particular configuration, which itself may be in part determined by the ease of accessing different crude inputs and current market conditions (EIA, 2015). Although refineries can adjust their configurations based on market conditions, these adjustments take time and can require the refinery to incur additional costs.

Although crude oil prices across locations generally move in tandem, there are significant spatial differences that vary across time (Plante and Strickler, 2021; Luong et al., 2019). For example, the West Texas Intermediate crude oil price is often viewed as the benchmark for domestic oil, but it is certainly not the only price oil is traded for in the U.S. One reason for spatial differences is that transportation costs can limit the ability of firms to engage in spatial arbitrage (Agerton and Upton, 2019; McRae, 2017), i.e. to move products from an area of low prices to an area of high prices to take advantage of the price difference.

In addition, crude oil is not the only input used in the production of fuels used by drivers. Other products, like lease condensates, naphthas, and biofuels, are often blended in to create a final product. Like any commodity, access to and prices for these inputs vary spatially and temporally.

For example, access to bio-feedstocks in the U.S. is concentrated in the

Midwest. Figure 6 depicts the refineries across the country and the ethanol capacity of each state. As can be seen, Nebraska, Iowa, Illinois, Minnesota, and South Dakota have the highest concentration of ethanol production. Not surprisingly, there is a very strong correlation between ethanol capacity[40] and corn stover production[41] across states.[42] This is intuitive, as logically one would build an ethanol fuel plant in geographic proximity of its feedstock, corn. Midwestern refineries likely therefore have greater access and lower transportation costs to acquire these bio-feedstocks. These refineries are likely impacted differently to changes in RIN prices relative to refineries that are not in close proximity to ethanol production.

Conclusion EPA's claim that the RFS compliance costs are the same for all obligated parties is implausible. There are many factors that impact an individual firm's output prices, production function, input quantities, and input prices. The effect of the RFS, and changes in RIN prices, on an individual refinery will depend on a combination of these factors.

3.2 EPA Claim 2: obligated parties recover their compliance costs through the market price

EPA (2021b) contains the following quote:

> *Obligated parties, including small refineries, recover their compliance costs through the market price they receive when they sell their fuel products and thus do not bear a hardship created by compliance with the RFS program.*[43]

As a corollary to Section 3.1, in this section, we will assess the plausibility of this claim utilizing economic theory presented in Section 2 alongside results of empirical research. From an empirical perspective, the measurement

[40] U.S. Energy Information Administration. Website. Petroleum & Other Liquids. U.S. Fuel Ethanol Plant Production Capacity (Mbpd). Contains data for U.S. fuel ethanol plants, as of January 1, 2021. Accessed Jan 12, 2022.

[41] National Renewable Energy Laboratory (NREL). Website. The Biofuels Atlas. Crop Residuals - Corn Stover. Accessed January 12, 2022.

[42] Specifically, the correlation coefficient is 0.94.

[43] Underline added for emphasis.

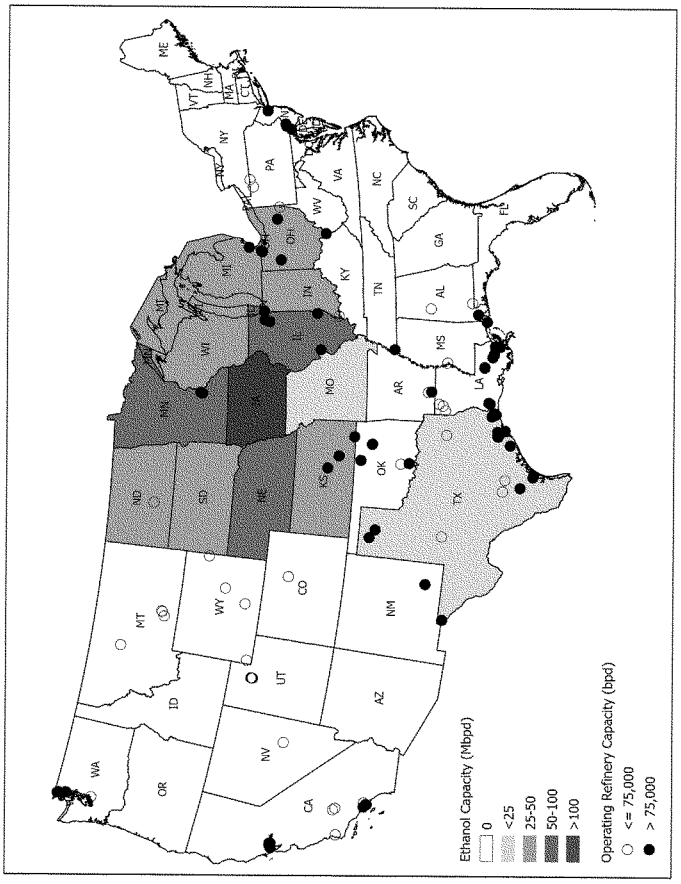


Figure 6: Ethanol Production Capacity and Refinery Locations

Source: U.S. Energy Information Administration. Ethanol production capacity from: Petroleum & Other Liquids. U.S. Fuel Ethanol Plant Production Capacity (Mbpd). Operating refining capacity from: Refining Capacity Report. Data from January 1, 2021. Note that SRE eligibility is based on a firm's actual production, not capacity thus some refineries might be eligible to apply for the exemption even though their capacity exceeds 75,000 bpd.

of pass-through of costs generally has proved to be challenging mainly because marginal costs and markups are typically non-observable in practical applications (Fabra and Reguant, 2014). These challenges are particularly salient in sectors that require large up-front investments (like refining) that necessitate high markups in equilibrium (Miller et al., 2017).

As discussed in Section 2, the incidence of compliance costs between producers and consumers in a competitive market theoretically is determined by the relative elasticities of the supply and demand. However, both the relative elasticities and the incidence of the policy between producers and consumers are empirical questions.

The price elasticity of demand for fuel is a widely studied topic in economics due to its policy relevance. Though obtained using varying empirical methodologies and data sets, estimates of this short-run demand elasticity have most often fallen in the range -0.1 to -0.4 (Levin et al., 2017; Coglianese et al., 2017; Graham and Glaister, 2002; Hughes et al., 2008; Li et al., 2014; Bento et al., 2009). Long-run demand elasticities of gasoline consumption tend to be larger in magnitude than their short-run counterparts, often falling between -0.6 and -0.8 (Graham and Glaister, 2002; Hausman and Newey, 1995). These larger long-run estimates suggest that consumers are more capable of adjusting their fuel consumption over longer time horizons. For example, these adjustments may take the form of purchasing a more fuel efficient vehicle or relocating to reduce commutes that may be difficult to accomplish immediately when fuel prices increase.

In contrast to the demand elasticity, the elasticity of supply has received less attention in the empirical literature. Researchers have often made assumptions about the magnitude of the supply elasticity—assumptions have included an elasticity of 2.0 and perfectly inelastic in the short run and perfectly elastic in the long run (Davis and Lutz, 2011; Austin and Dinan, 2005). However, Coyle et al. (2012) estimate a supply elasticity of gasoline of 0.29.

Assumptions and estimates of the supply elasticity appear to be larger in magnitude than the demand elasticities, suggesting more of the burden of the RFS program will fall on consumers. Given the general lack of estimates

of the supply elasticity of gasoline and that the existing estimates overlap with demand elasticity estimates, it is difficult to infer what share of the RFS compliance costs will fall on consumers and producers using this literature alone. However, several empirical papers have conveniently aimed to directly measure the extent that RIN prices are passed-through to consumers.

Utilizing daily price data from January of 2013 to March of 2015, Knittel et al. (2017) find that RIN prices pass-through to wholesale and retail fuel prices. Notably, while this study does find evidence of RIN price pass-through, the study states that "the fluctuations in the net RIN obligations are sufficiently small that for many spreads the pass-through coefficients and dynamics are imprecisely estimated." The paper also states that due to "the short span of the data . . . controlling for seasonal [fluctuations] also introduces imprecision." The authors also note that RIN prices do not appear to be passed-through to the national average E85 retail price.

Utilizing monthly confidential refinery-level data from 2012 to 2014, Burkhardt (2019) also finds that changes in the RIN prices were passed-through to nationwide wholesale gasoline and diesel prices on average. However, their results exhibit some spatial heterogeneity, with less pass-through occurring on the East Coast. This analysis finds the pass-through rates of the smallest and largest firms are not statistically significantly different from one another in the gasoline market. Interestingly, it appears that diesel production decreases with RIN prices while jet fuel production increases, suggesting refineries may attempt to avoid the costs associated with the RFS by shifting production to fuels not included in RFS. Further, they note that although aggregate crude oil price changes are fully passed-through, *refinery specific* crude oil costs are *not* fully passed-through.

Lade and Bushnell (2019) utilizes daily RIN and commodity price data from August 2012 through May of 2014, focusing on E85. The analysis estimates that half to three-quarters of the E85 subsidy is passed-through to consumers. However, this pass-through takes six to eight weeks, and station-level pass-through rates exhibit substantial heterogeneity, with the retailers' market structure influencing both the speed and level of pass-through.

Finally, Li and Stock (2019) analyze monthly data from 2007 to March

of 2015 on wholesale and retail prices for 274 Minnesota gas stations that sell both E10 and E85. They find evidence of RIN price pass-through to E10, but incomplete pass-through to E85. They argue the incomplete pass-through of E85 is a function of local market structure. In particular, the E85 market is sparse in many areas: "In the Twin Cities, which has a high density of E85 stations, pass-through is nearly complete, but outside the Twin Cities slightly less than half the wholesale discount of E85, relative to E10, is passed on to the consumer."

The literature appears to agree that RIN prices are largely or completely passed-through to national average E10 prices. Pass-through rates, however, appear to vary across space and are influenced by the local market structure. RIN price pass-through to diesel prices has received less attention than E10 and E85 prices, though the studies estimating this have found approximately full pass-through (Burkhardt, 2019; Knittel et al., 2017). Further, the literature does not find full pass-through to E85 prices. Indeed, the same disparities in pass-through to E10 prices that occur due to variation in local markets structure may be exacerbated for the much smaller E85 market.

In reviewing the literature, it is important to note that prior research largely has focused on ethanol based fuels, which are represented by D6 RINs. This is perhaps for good reason, as in 2019, D6 RIN retirements made up approximately 75 percent of the quantity of RINs.[44] D6 RINs also traded for the lowest value in 2019, averaging less than 20 cents per RIN throughout the year.[45] D6 RINs made up approximately half of the market value of all RINs, with D4 RINs (needed to meet biomass based diesel and advanced biofuels RVO) making up approximately 35 percent of market value.[46] Thus, empirical evidence finding complete pass-through of

[44]Source: United States EPA. Annual Compliance Data for Obligated Parties and Renewable Fuel Exporters under the Renewable Fuel Standard (RFS) Program. Table 3: Total RIN Retirements for Annual Completion. Data current as of November 10, 2020. Most recent compliance year available was 2019.

[45]Source: United States EPA. RIN Trades and Price Information. Simple average of Q-RINs for the 2019 transfer year.

[46]Market value obtained by multiplying total RIN retirements for annual compliance in 2019 times the Average RIN trading price in 2019. This calculation is meant to be descriptive. Not all RINs generated will be traded. Further, some traded RINs have

a specific RIN type to a specific market average product price should not be interpreted to mean that the cost of *all* RINs passes-through to final product prices for *all* obligated parties.

Conclusion EPA's claim that obligated parties recover compliance costs through the market price they receive when they sell their product is partially true.

The empirical literature corroborates EPA's claim that the RFS has lead to an increase in the price of fuel for consumers, thus increasing the price received by refineries. A review of the literature suggests that RIN prices are passed through to nation-wide average wholesale and retail prices, especially for E10. But the evidence does not suggest full pass-through of all RINs to all fuels in all locations. Thus, it is unlikely that market participants *in all situations* are able to recover their firm-specific compliance costs through the market price they receive when they sell fuel.

Further, EPA's statement notably omits that refineries will sell less liquid fuels because the market price is higher. The literature suggests a 1%–4% drop in short-run demand for a 10% increase in fuel prices and even larger decreases over longer horizons. The net effect of the RFS on aggregate refining producer surplus will be determined by a balance of (1) compliance costs, (2) higher market prices, and (3) reduced market demand due to higher market price. Thus, some of the incidence of the RFS very likely falls on refineries.

prices that are unverified by EPA, and therefore not included. Also, RIN prices change over time and this number represents the average weekly price as listed by EPA over the 2019 calendar year.

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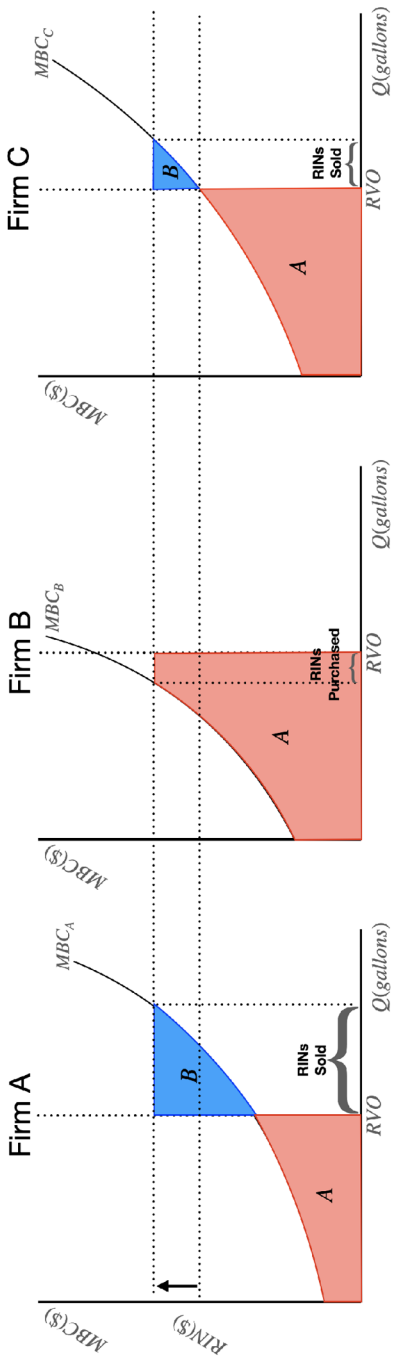


Figure A1: RIN Price Increase Illustrative Example

Source: Authors' sketch

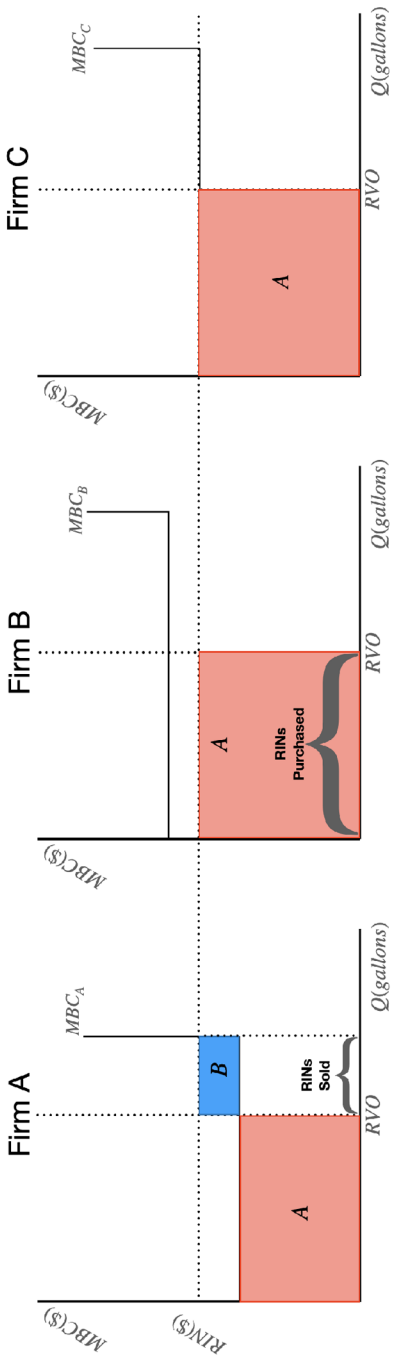


Figure A2: Marginal Blending Costs and Compliance - Constant Marginal Cost

Source: Authors' sketch

TAB D

Comments on EPA Proposed RFS Small Refinery Exemption Decision

Timothy Fitzgerald

I offer four major comments regarding the economic analysis presented in the Proposed RFS Small Refinery Exemption Decision.

1. Academic literature does not support the competitive market assumption asserted by EPA
2. EPA ignores jointness of production and implications for compliance
3. Competitive model asserted by EPA makes claims about market share ambiguous
4. EPA failed to provide evidence to substantiate the assumption of ratable RIN compliance

Detail of each of these issues follows.

1. Academic literature does not support the competitive market assumption asserted by EPA

EPA makes a strong assertion that "all obligated parties recover the cost of acquiring RINs by selling the gasoline and diesel fuel they produce at the market price, which reflects these RIN costs (RIN cost passthrough)." (p26 IV.D.2) As stated, this claims that all transactions fully recover RIN costs. EPA maintains this position throughout the proposed decision. This claim is not consistent with the empirical results relevant to this issue in the academic literature. EPA is relying too heavily on a very small number of results and making an interpretation that is unduly strong given the entire available empirical record. EPA has chosen its interpretation, but in so doing ignores complementary evidence that helps paint a more complete picture of how RFS compliance is achieved by different obligated parties.

a. EPA bases its review of the academic literature on a single study

EPA bases its position on single academic study (Knittel et al., 2017) and the working paper version of the published article that examined data from a subsequent period.[1] One other EPA document is also cited,[2] but only the single external study is cited in support of EPA's interpretation. While the Knittel et al. (2017) study is indisputably and influential study in this area, it is not the only work on the work in this area, and even taken by itself it does not fully support the position that EPA has elected to take.

b. EPA makes an overly strong interpretation of Knittel et al. (2017) results

Knittel et al. (2017) infer economic pass-through from a series of statistical tests on a collection of major wholesale fuel price spreads. While the statistical results are consistent with the notion that wholesale price spreads reflect changes in the calculated RIN obligation *on average*, it is a substantial leap to suggest that this happens in all cases. While the best guess in any particular case is that the obligation is passed through within a couple business days, and a vast majority of cases will be characterized by complete pass-through, that does not mean that every particular instance will be fully passed through in that timeframe.

[1] Knittel, C.R., Meiselman, B.S., and Stock, J.H. 2017. The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard. *Journal of the Association of Environmental and Resource Economists* 4(4), 1081-1119. The working paper examining subsequent data: Knittel, C.R., Meiselman, B.S. and Stock, J.H., 2016. The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard: Analysis of Post-March 2015 Data. Working Paper.

[2] Burkholder, D., 2015. A preliminary assessment of RIN market dynamics, RIN prices, and their effects. Office of Transportation and Air Quality, US EPA.

EPA's interpretation appears to be most consonant with the pooled results reported in table 3 of Knittel et al. (2017), but even in that case the standard error of the pooled estimate is not zero and gasoline and diesel evidence different pass-through. Even the closely estimated pooled result allows for variation around the point estimate. EPA ignores the proper statistical interpretation of the only external study that it cites by claiming that there is complete and immediate pass-through in all cases in all submarkets.

c. Other studies provide strong evidence for imperfect pass-through

The substantial academic literature that provides evidence of imperfect pass-through undermines EPA's chosen interpretation. Lade & Bushnell (2019) is one such study,[3] concluding that between half and three-quarters of the RIN cost is passed through to E85 prices. It is worth noting that this occurs over the substantially longer period of 6-8 weeks rather than two business days. Even while allowing for the possibility of complete pass-through on average, this result undermines the position that EPA has taken in the proposed decision. The results contrast subtly with the long-run pass-through model of Knittel et al. (2017) and provides more recent empirical support for the conclusion presented by Pouliot and Babcock (2016) that short-run compliance costs for obligated parties can be substantial.[4] Lade and Bushnell (2019) highlight the heterogeneity in pass-through in part depending on market size and integration of retail.

[3] Lade, G.E. and Bushnell, J., 2019. Fuel subsidy pass-through and market structure: Evidence from the renewable fuel standard. *Journal of the Association of Environmental and Resource Economists*, *6*(3), 563-592.
[4] Pouliot, S. and Babcock, B.A., 2016. Compliance path and impact of ethanol mandates on retail fuel market in the short run. *American Journal of Agricultural Economics*. *98*(3), 744-764.

The Lade and Bushnell (2019) result of less than full pass-through to E85 is consistent with the result from Li and Stock (2019),[5] which used a different dataset and concluded that pass-through depends on the depth of the market for E85. Introducing the geographic variation in pass-through underscores that some assets in transportation fuel supply are not fully flexible in the short run, and hence compliance costs can differ across obligated parties.

Because E85 is the only finished fuel that can absorb additional required volumes of biofuels in the gasoline markets beyond standard oxygenate requirements, the slow and incomplete pass-through indicates that the marginal gallon of biofuel in transportation fuel may not be passed through as smoothly as inframarginal gallons are. Indeed, for RVOs below a traditional E10 blend, RINs did not have substantial economic value because blenders voluntarily chose to blend biofuels to enhance fuel performance and meet other requirements. Only after EPA increased RVOs beyond the blend wall was the financial incentive of the RIN needed to promote additional or excess blending of biofuels into the transportation fuel supply. The disparity in the retail gasoline market can explain the divergence between empirical estimates of average and marginal pass-through.

Burkhardt (2019) presents further useful results by studying margins across which pass-through varies.[6] The aggregate pass-through result corroborates the Knittel et al. (2017) result of pass through on average, with a tighter relationship estimated in gasoline markets as opposed to diesel markets. The size of the obligated parties and the region of the country where obligated parties are located affect the pass-through relationship. These results are important because they show

[5] Li, J. and Stock, J.H., 2019. Cost pass-through to higher ethanol blends at the pump: Evidence from Minnesota gas station data. *Journal of Environmental Economics and Management*, *93*, 1-19.
[6] Burkhardt, J., 2019. The impact of the Renewable Fuel Standard on US oil refineries. *Energy Policy*, *130*, 429-437.

that average pass-through can mask relevant variation in the ability of obligated parties to recover RIN costs.

Further evidence that the complicated structure of the fuel supply sector may affect pass-through comes from Pouliot et al. (2017),[7] which documents the variation in pass-through at gasoline terminals depending on the number of products offered and the region of the terminal. In particular, there is evidence that pass-through does not occur on the East Coast, and data from the West yields imprecise estimates of pass-through. These results corroborate the findings in Burkhardt (2019) that pass-through on average can mask local or specific instances where the mechanism does not operate in the same way. The results from the West also suggest that evidence of pass-through at one time does not necessarily mean there will be pass-through in a different time period.

Ignoring the substantial evidence from other academic papers that pass-through is imperfect further undermines the strongly competitive interpretation that EPA has elected to make based on results from a single external study. In light of the fact that many of these studies have a similar finding that pass-through does occur on average, but there are circumstances in which pass-through is incomplete; EPA could consider the implications for the assertion that the RIN market is everywhere and always competitive.

d. National policies increase pass-through on average, but also pass-through heterogeneity

Recent research indicates pass-through depends on the nature of cost shocks. In work that addresses pass-through of price shocks in the oil refining sector, but does not address RINs

[7] Pouliot, S., Smith, A. and Stock, J.H., 2017. RIN pass-through at gasoline terminals. Working Paper.

explicitly, Muehlegger and Sweeney (2021) find evidence of variable pass-through.[8] This work helps resolve a standing economic puzzle about pass-through. If compliance costs vary across firms, then the extent of pass-through will also vary. If compliance costs are uniform, then the pass-through across the industry is likely to be comparable. The model and matching results in Muehlegger and Sweeney (2021) suggest that pass-through does vary across relevant margins. This suggests that compliance costs—costs directly attributable to RFS—may also vary in statistically and economically significant ways across firms. These important results from the same industry deserve consideration for firms that bear a higher-than-average share of costs, which could be restated as "disproportionate economic harm" directly attributable to the RFS.

More pointedly, Muehlegger and Sweeney (2021) demonstrate that increasing pass-through on average (such as shown by Knittel et al. (2017)) also increases the variation in ability to pass-through costs across firms within the industry. If EPA recognizes that RFS is a national policy affecting all firms, then it must also recognize that this increases heterogeneity in the ability of firms to pass-through higher costs, introducing the possibility that some firms are disproportionately affected by the program

To conclude, the strong assertion by EPA overstates the empirical record, in particular where the academic literature has documented examples of differences in pass-through across various margins. Recent results about the tradeoff between average pass-through and pass-through heterogeneity are especially relevant but ignored by EPA.

[8] Muehlegger, E. and Sweeney, R.L. 2021. Pass-Through of Own and Rival Cost Shocks: Evidence from the U.S> Fracking Boom. *Review of Economics and Statistics.* Forthcoming.

2. EPA ignores jointness of production and implications for compliance

Because of RIN convertibility, firms can choose how to comply with RFS requirements, though not all strategies taking advantage of convertibility are likely to be advantageous. Obligated parties understand the nesting and overall cap, but the assumption that transportation fuels markets are strongly separable ignores the linkage provided by RFS and the jointness in production that may limit ability to alter obligations, even over an extended time horizon. EPA ignores these issues in the proposed decision rule and simplifies its narrative of the industry. This is starkly exhibited in the expression of Equations (1) and (2) in the proposed decision rule.

a. EPA ignores recent academic literature suggesting that the marginal RIN is D4

Irwin et al. (2020) provide evidence that factors related to policy interactions complicate RIN price dynamics.[9] Specifically, the peripatetic authorization of the biomass-based diesel tax credit has introduced policy uncertainty to the nested structure of RIN compliance. In practical terms, this means that it can be cheaper and easier to comply with the RFS by paying for a D4 RIN that tracks the higher production cost of biodiesel relative to petroleum-based diesel than it is generate additional D6 RINs by blending E85 that must be sold at an uncertain discount.

This development differs from the model presented in figure 4 in Knittel et al. (2017), which presumes separation between the D4 and D6 RINs. Put another way, when the D4 subsidy is sufficiently small, obligated parties can reduce costs by surrendering D4 rather than D6 RINs. But the difficulty that EPA faces in anticipating regulatory regimes when setting RVOs means

[9] Irwin, S.H., McCormack, K. and Stock, J.H., 2020. The price of biodiesel RINs and economic fundamentals. *American Journal of Agricultural Economics*, *102*(3), pp.734-752.

that there can be both persistent and volatile spreads in D4 RINs that can provide a time-dependent fluctuation in compliance costs.

b. Linkages between fuels markets limit flexibility for specialized obligated parties

Refiners accrue obligations based on refinery throughput, which is determined in part by configuration. Refinery configurations can change with investment over time but may be fixed in the short term. As an example, an obligated party producing mostly diesel fuel will not have the option to blend to separate RINs for compliance and is forced to purchase D4 RINs to meet the RVO. Given that diesel markets exhibit less pass-through on average than gasoline markets, this may limit the ability to recover costs. Conversely, a gasoline-heavy obligation can try to enter the blending market to take advantage of separation, or exploit nesting to use wither D6 or D4 RINs as prices allow.

EPA could present a joint model of equations that would reflect the jointness in compliance created by RIN convertibility and physical limitations that exist in the short run. If EPA conceives of Equations (1) and (2) as long-run conditions, that should be explicit. Constraints on adjustment between the short run (cf. Pouliot and Babcock (2016)) and EPA's view of industry dynamics in the long run exist and are uneven across regions and firms. This creates potential for disproportionate economic harm.

3. Competitive model asserted by EPA makes claims about market share ambiguous

EPA asserts that the underling RIN market is competitive and that pass-through is complete and immediate in all cases. It further typifies the transportation fuels market as "highly competitive" (p26 IV. D. 2.) both in terms of refining and fuel blending. Given this assertion, it is peculiar that EPA focuses on the dynamic by which "competitors will give up the revenue from the sale of RINs to gain a greater market share" (p35, IV.D.2.b.) because market share would not seem to be a valuable end to itself in a highly competitive market.

There are possible explanations for the focus on market share in a competitive setting, such as developing or enhancing local market power or costs that depend on share or volume. It is not clear from the brief mention of market share which, if any, of these channels EPA has in mind.

The most intuitive explanation is that there are varying degrees of local or regional market power, and obligated parties seek to develop and exploit such power. This reality contrasts starkly with EPA's assertion that refined products are competitive and always and everywhere facilitate pass-through of RFS compliance costs for all parties.

4. EPA has failed to provide evidence to substantiate the assumption of ratable RIN compliance

EPA relies on the notion that if obligated parties comply with RFS requirements by acquiring RINs as obligations accumulate—which is termed *ratable* compliance—then the obligated parties will be assured of meeting RFS requirements. EPA goes a step further by suggesting that any non-ratable compliance strategy cannot be the basis for disproportionate economic harm. EPA has the means to provide evidence on this front, which has been lacking to date.

a. Academic literature indicates that timing of pass-through varies

EPA relies on the Knittel et al. (2017) result that RIN obligations are reflected in fuel prices on average within about two business days. As mentioned above, other studies indicate that the period for pass-through can be substantially longer. Lade and Bushnell (2019) find that pass-through to E85 prices can take as long as six to eight weeks on average. Burkhardt (2019) uses monthly data in assessing pass-through. Pouliot et al. (2017) use weekly data in assessing pass-through at gasoline terminals, finding that multiple regions of the country do not show signs of pass-through in that time period. If pass-through varies in time, then an obligated party would want to match its compliance strategy with the timing of pass-through. EPA has made a strong assumption about the timing of pass-through that ignores differing results in the literature.

Given these differing results, which vary by product and region, it would be understandable for obligated parties to match their compliance strategy with the timing of pass-through in the markets most relevant to their operations. EPA apparently does not agree, stating "all obligated parties have the ability to match their RIN costs with the price they receive when they sell their fuel (i.e., to pass through their RIN costs)." (p49. IV.D.2.d.i.) If empirical results indicate that pass-through is not immediate, then ratable compliance will necessarily force an obligated party to hold an uncovered position in the RIN market. EPA regards this behavior as speculation, and "EPA strongly disputes that costs resulting from an individual refinery's business decisions…represent DEH *caused* by the RFS program." [emphasis original] (p49 IV.D.2.d.i.) EPA claims that all compliance should be ratable yet chooses to ignore evidence of differences in timing of pass-through that would lead obligated parties to make decisions about RINs over longer time periods. This inconsistency could lead an obligated party to try to ratably comply yet

not receive complete pass-through because of fluctuations in RIN or fuel markets over a longer time required for pass-through to occur in certain product or regional markets. Such situations cast doubt on EPA's assertion that trading activity to comply with the RFS cannot cause disproportionate economic harm.

b. Academic literature assumes ratable compliance, but price dynamics matter

How RIN prices vary has attracted substantial attention. Mason and Wilmot (2016) account for the effect of price jumps in the RIN market,[10] and underscore the importance of this modeling assumption in understanding price behavior. This becomes significant because of the underlying presumption that firms are able to pass price changes through to customers. If price dynamics are such that RIN prices jump while an obligated party is holding RINs and waiting for those costs to pass-through to product markets, the obligated party could be exposed to unwitting and unwelcome price risk. Yet EPA claims that such an event would be speculation on the part of the obligated party. The position staked out by EPA ignores recognized price dynamics that put an obligated party in an impossible situation.

Two factors are relevant to this issue. One is liquidity in the RIN market. EPA asserts that "RINs are widely available in an open and liquid market" (p26, IV.D.2.), but does not quantitative metrics of that liquidity. Providing evidence of the market liquidity in all RIN categories across time periods would help reduce concerns about illiquidity as a cause of disproportionate economic harm because of the RFS program.

[10] Mason, C.F. and Wilmot, N.A., 2016. Price discontinuities in the market for RINs. *Journal of Economic Behavior & Organization*, *132*, pp.79-97.

A second issue is the costs of transaction, and particularly how those might vary across firms. The Burkholder memo address the issue of transactions within and between firms being fundamentally the same (p6), but does not explore potential cost differences. Providing evidence on this issue would help reduce concerns about this channel for disproportionate economic harm as a result of the RFS program. Reports of RIN generation provided by the EMTS program report overall caps but do not differentiate between RINs that remain within one firm and those that change hands between parties.

c. EPA has conducted analyses that are not shared

EPA repeatedly refers to "analyses" it performed (e.g., p44, IV.D.2.d.) but there is no transparency to evaluate the methods by which EPA has reached its conclusions. There is no description of data or empirical methodology, nor are results provided. Instead, EPA provides only conclusions. It is possible for EPA to share more detail about additional analyses that bear on the decision. To the extent that these analyses use different models or data than publicly-available results, sharing the analyses would improve understanding and improve transparency.

d. EPA has data that could demonstrate ratable compliance

EPA's argument about RIN compliance relies heavily on the ratable basis for compliance. EPA clearly states that any EPA does have access to RIN logs, which could be used to demonstrate that obligated parties have similar compliance patterns and costs. While providing the raw data might not be practical for confidentiality concerns, EPA could do more to provide transparency

about analyses and key results. As it stands today, EPA is relying on a single external study and one internal memo from 2015.

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PROFESSIONAL EXPERIENCE

Associate Professor (without tenure), Rawls College of Business, Texas Tech University
August 2015–present

Chief International Economist, Council of Economic Advisers, Executive Office of the President April 2018–December 2018

Senior Economist, Council of Economic Advisers, Executive Office of the President
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Assistant Professor, Agricultural Economics & Economics, Montana State University
January 2009–August 2015

Adjunct Instructor, Agricultural Economics & Economics, Montana State University
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EDUCATION

Ph.D., Agricultural and Resource Economics, University of Maryland, January 2009
Dissertation Title: *Essays on Split Estates in Energy Development*

A.B., *summa cum laude* in Economics and Environmental Studies, Bowdoin College, 1997

PUBLICATIONS

Refereed Journals

Fitzgerald, Timothy and Michael Giberson. *2021.* Wind Project Performance with Age: Policy, Technology, Markets, and the Maturing Wind Power Industry. *The Electricity Journal*. 34(10): 107047.

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Book Chapters

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Fitzgerald, Timothy. 2018. Regulatory Obsolescence through Technological Change in Oil and Gas Extraction. *Environmental Law and Policy Review* 43(1): 137–171.

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Fitzgerald, Timothy. 2020. *George P. Mitchell: Fracking, Sustainability, and an Unorthodox Quest to Save the Planet* by Loren Steffy. *The Energy Journal*. 41(6):

283–284.

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Other Publications

Fitzgerald, Timothy. 2020. Environmental Costs of the Jones Act. Policy Analysis #886. Cato Institute: Washington, DC.

McGowen, Patrick, Jaydeep Chaudhari, Brian Church, Janelle Booth, Timothy Fitzgerald, Daniel Richter, and Robert J. Eger III. 2011. Montana Fuel Tax Refunds: Final Report. Western Transportation Institute, Bozeman, MT.

Fitzgerald, Tim. 2000. Federal Land Exchanges: Let's End the Barter. *PERC Policy Series* #18. PERC: Bozeman, MT.

Current Working Papers

Whose Frac is It, Anyway? Using Innovations to Explain Industrial Organization in Oilfield Services (with Charles F. Mason)

The Economic Costs of Green Recovery Plans (with Casey B. Mulligan)

The Environmental Costs of the Jones Act

Regulatory Capture in a Resource Boom

The Effects of Oil and Gas Fiscal Regimes on Exploration and Production Decisions (with Andrew Stocking)

Achieving Negative Carbon Leakage through Sectoral Border Adjustment Reductions

Permanent Working Papers

The effects of Biden's tax and regulatory agenda on long run economic activity (with Kevin Hassett, Casey B. Mulligan, and Cody Kallen) *2020*

Protecting Rhinos through Legal Horn Trade (with Michael t' Sas-Rolfes) *2013*

FELLOWSHIPS AND AWARDS

Nonresident Fellow, American Center for Capital Formation, 2019
John V. Krutilla Research Fellow, Resources for the Future, 2012–2013
Meridian Institute Conservation Leadership Partnership Fellow, 2012
Lone Mountain Fellow, Property and Environment Research Center, 2012, 2016
Noyes Political Economy Prize, Bowdoin College, 1997
Surdna Foundation Undergraduate Research Fellowship, 1996–1997

GRANTS

Hayek Fund for Scholars, Institute for Humane Studies, 2020
USDA NIFA AFRI, Effects of Oil and Gas Development on Agriculture, 2014–2019
Faculty Excellence Grant, Montana State University, 2013–2014
Faculty Development Award, Montana State University, 2011
Research Enhancement Award, MSU Letters & Sciences, 2009–12
Jacob Goldhaber Travel Grant, University of Maryland, 2007

PRESENTATIONS

Invited

2020 Air Force Academy; Bowdoin College (postponed); Cornell University (Dyson).
2019 University of Tennessee; Baylor University.
2017 Dallas Federal Reserve; Texas Christian University; Texas Tech University (AAEC).

Conference

2021 AERE Virtual Summer Conference; IEW Workshop, Freiburg, DE; CU Environmental and Resource Economics Workshop, Vail, CO; Energy Policy Conference, Boise, ID; USAEE/IAEE Virtual Conference.

2020 Rice Center for Energy Policy, Houston, TX; Hoover Institution, Stanford, CA (postponed); AERE Virtual Summer Conference; 40th OECD Round Table on Sustainable Development, Paris, FR.

2019 AERE Summer Conference, Lake Tahoe, NV; EMEE Workshop, Quebec City, QC; JPMCC International Workshop, Denver, CO; USAEE/IAEE North American Conference, Denver, CO; NU-CMU Energy Workshop, Chicago, IL; Southern Economics Association, Ft. Lauderdale, FL.

2017 ASSA Annual Meeting, Chicago, IL; AERE Summer Conference, Pittsburgh, PA; SIOE Conference, New York, NY.

2016 ASSA Annual Meeting, San Francisco, CA; Center for Energy Studies, Houston, TX; AERE Summer Conference, Breckenridge, CO; CAES-WAEA Joint Annual Meeting, Victoria, BC; USAEE /IAEE Conference, Tulsa, OK.

2015 AAEA-WAEA Joint Annual Meeting, San Francisco, CA; 17th Annual University of Colorado Environmental and Resource Economics Workshop, Vail, CO; 34th USAEE/IAEE Conference, Pittsburgh, PA; Southern Economics Association Meeting, New Orleans, LA.

2014 ASSA Annual Meeting, Philadelphia, PA; Unconventional Gas and Oil Development Workshop, Morgantown, WV; Western Economic Association Annual Conference, Denver,

CO; NBER EEE Summer Institute, Cambridge, MA; CREE Annual Meeting, Saskatoon, SK; National Tax Association, Santa Fe, NM.

2013 Big Sky Energy Forum, Billings, MT; AERE Summer Conference, Banff, AB; WAEA Annual Meeting, Monterey, CA; Western Economic Association Annual Conference, Seattle, WA; CESifo Venice Summer Institute, Venice, IT; 32nd USAEE/IAEE Conference, Anchorage, AK; 14th Occasional California Workshop in Environmental and Resource Economics, Santa Barbara, CA.

2012 ASSA Annual Meeting, Chicago, IL; Providing Environmental Services from Agriculture Conference, Washington, DC; Congressional Budget Office, Washington, DC; WAEA Annual Meeting, Park City, UT; 31st USAEE/IAEE Conference, Austin, TX.

2011 30th USAEE/IAEE Conference, Washington, DC; CAES-WAEA Joint Annual Meeting, Banff, AB; 13th Annual University of Colorado Environmental and Resource Economics Workshop, Vail, CO.

2010 29th USAEE/IAEE Conference, Calgary, AB.

Other Workshops

2021 NBER Economics of Energy Innovation (invited); NBER New Directions in Transport Economics; EMEE Virtual Conference; J.P. Morgan Center for Commodities Annual Research Workshop; Annual Conference on Innovation Economics.

2020 Workshop on Gas Flaring, Austin, TX (participant); NBER Economics of Transportation and Infrastructure in the 21st Century (participant); CEBRA Workshop on Commodities and Macroeconomics; FRB Richmond Climate Workshop (invited); Dallas and Kansas City Fed's Energy and the Economy Conference (invited).

2019 Oil & Gas Volatility Workshop, Golden, CO (panelist); Breakthrough Dialogue, Sausalito, CA (panelist); International Commodities Symposium, Denver, CO (panelist); Texas Stata Microeconometrics Workshop, Houston, TX (attendee).

PROFESSIONAL ACTIVITIES

Editorial

Advisory Board, *Energy Research Letters*, 2020–present
Book Review Editor, *The Energy Journal*, 2017–present

Reviewer

American Economic Journal: Economic Policy, *Ecological Economics*, *Economic Inquiry*, *Energy Economics*, *Energy Journal*, *Energy Policy*, *Journal of the Association of Environmental and Resource Economists*, *Journal of Environmental Economics and Management*, *Journal of Law & Economics*, *Journal of Political Economy*, *Land Economics*, *Regional Science and Urban Economics*, *Resource and Energy Economics*, *Review of Environmental Economics and Policy*

TAB E

Overview

Daily bulk sales data from a collection of small refiners were analyzed to assess the extent of pass-through of RIN costs. This methodology follows directly from Knittel et al. (2017), is similar to that adopted by other more recent analyses such as Lade and Bushnell (2019). It also seems to be the preferred methodology of EPA in the proposed final decision rule (though it's a bit hard to tell from the description).

Data

Sales data were reported from 19 sales locations for 76 products over the calendar years 2019–2021. These data differ from other publicly-available analyses in three ways. First, they are drawn from a more recent time period than previous analyses, allowing for more timely inference about market conditions. Second, these data are detailed in terms of daily (and in some cases lot by lot) sales of specific refined products with specific counterparties at specific locations, which reflects the commercial conditions faced by obligated parties and contrasts with other studies that compare price spreads between index and average prices. By the same token, these detailed data allow inference in market segments rather than relying on pooled results. Third, the data are drawn exclusively from a group of small refiners as sellers; this group has asserted disproportionate economic harm from RFS and is directly affected by the proposed rule.

The 19 locations are located across 10 states and 4 PADDs (PADD 2 has no observations). The 76 products are quite specific, such as B2 #2 dyed ULSD (15ppm) or 87 octane E10 gasoline with branded additive. This broad array reflects the strength of the assumption that RIN prices pass through completely and immediately in all product markets. It also provides an opportunity to test the assumption in a large number of applications to determine if it is justified.

To facilitate analysis, these specific products are aggregated into fuel type categories, with pricing for the category reflecting a volume-weighted average of reported transaction prices. For example, 11,031 daily transactions across 10 distinct fuel types are aggregated into the E0 category and 26,346 daily transactions across seven fuel types are aggregated into the E10 category. The estimates compare pairs of fuels priced at the same location and yield parameter estimates that reflect the average tendency across all pairs in all locations. It is worth considering that the aggregation means that the E10 price can reflect an average across two grades of E10, such as 87 and 93 octane or branded and unbranded 87 octane, at a given location on a given day. To the extent different grades of E10 are sold at the same location on different days, the series treats the different grades as substitutes.

An important issue in these data is the treatment of weekend fuel sales. Knittel et al. (2017) drop weekends, and RIN price quotes are not available for weekends and major holidays. Refining and fuel supply is a 24/7/265 industry, which is borne out in the

data, with about 28 percent of all transactions logged on Saturday or Sunday. This has serious implications for the assumption of ratable compliance asserted strongly by EPA. To investigate further, a linear interpolation of missing RIN prices was created (the difference between Friday and Monday quotes is split between Saturday and Sunday for a regular weekend). This permits comparison with the transactions on reported days and all observed sales using the interpolated values. Not that this method does not introduce additional variance into the regressors, but it does increase the variance of the prices to be explained.

Empirical Strategy

EPA stylizes the refined product market in the proposed final decision rule in their equations (1) and (2). These equations are rearranged slightly to afford empirical estimation of the extent to which product prices reflect complete and immediate pass-through of RIN costs in all cases as asserted by EPA.

The analysis focuses on three bulk price spreads that identify how the difference in prices between obligated and unobligated fuels are related to movements in RIN prices. These three price spreads are E0 - E10, B0 - B2, and B0 - JET/KERO. The obligations in each case are slightly different. The B0-B2 spread is a very tight differential that has not previously been used as the basis for estimation. These particular data permitted testing it as an application of pass-through.

For each blend represented as ϕ (e.g., $\phi = 0.10$ for E10), the net RIN obligation can be represented as

$$R_t^{ij} = \mathbf{RVO}\ \mathbf{P}(1-\phi) - \phi RIN_t \tag{1}$$

This allows for an estimable equation to explain the difference in prices between fuels i and j as a function of R_t^{ij} at the time (t) and location (ℓ) of sale

$$\Delta p_{\ell t}^{ij} = \alpha_{\ell ij} + \beta_{ij} R_t^{ij} + \varepsilon_{\ell t}^{ij} \tag{2}$$

where ε is an error term. This is identical to equation (2) in Knittel et al. (2017).

Results

The first set of results estimate equation 2 for each of three fuel spreads in 2019–2021 using OLS with Newey-West standard errors to account for autocorrelation. This is the methodology used by Knittel et al. (2017) for an earlier period and endorsed by EPA. Results are reported in table 1, The results for E0 - E10 indicate that there is pass-through on average, consistent with earlier findings (e.g., Knittel et al. (2017)). It is worth noting, however, that the point estimate is 0.123, which indicates that contemporaneous product pricing reflects only 12.3% of RIN variation. The wide variation in the ability of sellers to affect product pricing means that there is not a statistical difference between 12.3% and 100%, even as there is a large commercial difference.

Table 1: Pass-Through Estimates without Weekends

	E0 - E10	B0 - B2	B0 - KERO/JET
	0.123	-0.034***	1.574***
	(0.799)	(0.013)	(0.059)
N	3,977	1,902	1,172

Each column reports β coefficient from a separate regression of equation 2 with the dependent fuel price spread listed at the top of the column. Regressions also include seasonal, facility, and volume controls that are not reported. Standard errors in parentheses are Newey-West, allowing for autocorrelation. Stars indicate whether the hypothesis that the parameter is equal to 1 is rejected, with $*p < 0.1, **p < 0.05, ***p < 0.01$.

The B0-B2 diesel spread has not been estimated elsewhere and may be too tight to provide meaningful inference, but does not show evidence of pass-through. The point estimate is very close to zero and is significantly different from one. This suggests that the price differential between B0 and B2 does not reflect changes in RFS compliance costs.

The ULSD-KERO/JET spread shows evidence of pass-through (coefficient 1.574 and significantly greater than 1), though there may be physical differences and segmented markets that account for that difference. Buyers of jet fuel cannot substitute to diesel (and vice versa) the way most buyers of E0 and E10 can substitute between the two. Note that pooling across all fuels (like Knittel et al. (2017)) would indicate that there is near-complete pass-though on average.

For all three fuel spreads the volumetric controls are statistically significant and negative for all specifications reported in tables 1 and 2. This suggests that there may be relevant economies of scale. The estimates reported here control for that effect.

The second set of results estimate equation 2 for each of three fuel spreads using the data that include weekends. The results indicate that there is less evidence of pass-through when weekend transactions are included. Notably, the results presented in table 2 suggest that the degree of pass-through in the gasoline market is significantly different from 1. The results for the diesel spreads do not change substantively when weekends are included—the degree of pass-through is significantly different from complete and immediate.

The point estimate and large confidence interval when including interpolated RIN obligation data over weekends draws into question the relevance of ratable compliance assumptions, because trading arrangements for RINs are substantially less liquid on weekends, and waiting until the next weekday may expose obligated parties to price risk inherent to

compliance. EPA expressly ignores such a pathway as being "caused by RFS."

Table 2: Pass-Through Estimates with Weekends

	E0 - E10	B0 - B2	B0 - KERO/JET
	-0.789**	-0.027***	1.630***
	(0.747)	(0.016)	(0.096)
N	5,246	2,630	1,672

Each column reports β coefficient from a separate regression of equation 2 with the dependent fuel price spread listed at the top of the column. Regressions also include seasonal, facility, and volume controls that are not reported. Standard errors in parentheses are Newey-West, allowing for autocorrelation. Stars indicate whether the hypothesis that the parameter is equal to 1 is rejected, with $*p < 0.1, **p < 0.05, ***p < 0.01$.

Table 3: Pass-through Estimates by PADD (with Weekends)

	E0 - E10	B0 -B2	B0 - KERO/JET
PADD 1	-7.461***	-0.044***	
	(2.909)	(0.017)	
PADD 3	-1.631***	0.045***	0.535
	(0.582)	(0.031)	(0.747)
PADD 4	3.278**		1.686***
	(0.896)		(0.105)
PADD 5	12.352***		1.469*
	(1.604)		(0.239)

Each column reports β coefficient from a separate regression of equation 2 with the dependent fuel price spread listed at the top of the column. Regressions also include seasonal, facility, and volume controls that are not reported. Standard errors in parentheses are Newey-West, allowing for autocorrelation. Stars indicate whether the hypothesis that the parameter is equal to 1 is rejected, with $*p < 0.1, **p < 0.05, ***p < 0.01$.

The third set of results explore differences in pass-through by PADD using similar approaches to those reported in table 2. These are reported in table 3. In all but one case,

the hypothesis that pass-through is complete and immediate is rejected. Taken together, the results indicate widely varying conditions around the country. Weekends are included here to bolster sample sizes as the transactions data are divided to explore regional heterogeneity. This may be asking too much of the data, as the number of observations for each regression dips as low as 92. More transactions, potentially over a longer time period, are needed to remedy this fault. The results can be taken as illustrative of the variation that accumulates in the fuels supply chain in different regions, but should not be regarded in the same light as the pooled regressions.

Conclusions

1. These specifications account for differences in pass-through due to volume effects. Larger sales lots consistently and significantly receive higher prices, and the differences also appears to be commercially significant. While economies of scale are likely present in oil refining and bulk fuel sales, this isolation of this effect in the context of RFS compliance is relevant to the statutory allowance for SRE. It also isolates all remaining variation as directly attributable to RIN cost variation, having controlled separately for size effects.

2. In this sample of sales by small refineries, pass-through rates appear to be lower and more variable than in larger samples such as Knittel et al. (2017). For example, the gasoline pass-through coefficient in table 1 falls by nearly 30 percent when weekends are included in table 2. Neither coefficient is significantly different from 1 because there appears to be wide variation in the extent to which pass-through is occurring.

3. Excluding weekends appears to overestimate estimates of pass-through, with less pass-through when weekends are included. This is relevant to discussions of ratable compliance, because RIN markets are likely not as liquid during weekends for lack of price discovery and deepness of the market.

4. Pass-through varies substantially across fuels. This is evident from the analysis of one bulk gasoline and two bulk distillate spreads, which yield substantively different estimates pass-through, and is consistent with earlier work on this topic.

5. There appears to be substantial variation in pass-through by region, and by fuel. These estimates are straining the available data and should be taken as suggestive rather than definitive.

6. Variation in estimates of pass-tough suggests that EPA's assumption of complete, immediate, and comprehensive pass-through does not hold in all cases.

References

Knittel, Christopher R, Ben S Meiselman, and James H Stock, "The pass-

through of RIN prices to wholesale and retail fuels under the renewable fuel standard," *Journal of the Association of Environmental and Resource Economists*, 2017, *4* (4), 1081–1119.

Lade, Gabriel E and James Bushnell, "Fuel subsidy pass-through and market structure: Evidence from the renewable fuel standard," *Journal of the Association of Environmental and Resource Economists*, 2019, *6* (3), 563–592.

Senator CARPER. Ms. Koch, thank you so much.

Before we begin questions, I am going to ask unanimous consent to place into the record materials on historical fuel and energy prices.

Hearing no objections, so ordered.

[The referenced information follows. Due to size constraints a document is not included below but is available in Committee files.]

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Source: https://www.statista.com/statistics/1109332/us-oil-and-gas-rigs-in-use-covid19/

Active oil and gas rigs in the U.S. 2019-2022

Published by N. Sönnichsen, Mar 1, 2022

The number of operational U.S. oil and gas rigs totaled 650 in the last week of February 2022. Figures had decreased to a low of 251 units in July 2020. This was a decline of over 500 units compared to February of that year and a direct result of the oil crisis and falling oil prices, which resulted from lower fuel demand during the coronavirus pandemic.

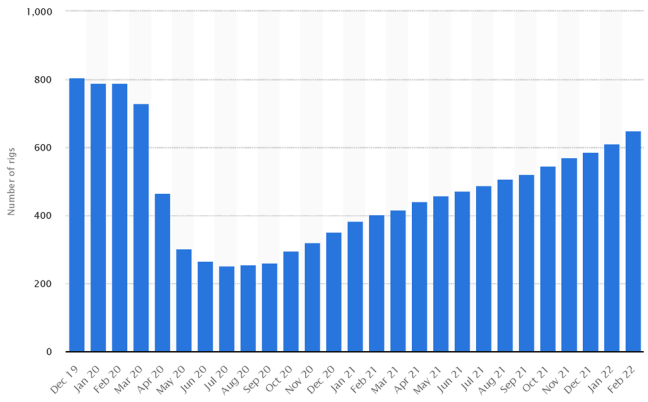
Most common rig types

Oil rigs are the most common wells drilled in the U.S. At the end of 2021, there were some 480 active oil rigs compared with roughly 106 gas rigs. This discrepancy has been exacerbated over the years, with there being a less pronounced difference in 2011. 2011 was also the year when new well drilling numbers peaked within the past decade, with roughly 2,000 newly bored oil and gas extraction sites. The majority of oil rigs are found in the Permian Basin. Located in Texas and parts of New Mexico, the Permian Basin has been a harvesting ground for petroleum since the early 1920s and since established itself as the most productive U.S. oil basin.

Future U.S. oil production

A February 2021 forecast sees U.S. shale gas and tight oil production reach roughly 34 trillion cubic feet by 2050. Between 2020 and 2025 production is projected to increase by four trillion cubic feet.

Number of United States oil and gas rigs in operation at the end of each month from December 2019 to February 2022



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Region
United States

Survey time period
December 2019 to February 2022

What is behind soaring energy prices and what happens next?



Carlos Fernández Alvarez, Senior Energy Analyst
Gergely Molnar, Energy Analyst – Natural Gas
Commentary — 12 October 2021

Cite Share

Gas, coal and electricity prices have in recent weeks risen to their highest levels in decades. These increases have been caused by a combination of factors, but it is inaccurate and misleading to lay the responsibility at the door of the clean energy transition.

In this commentary, we provide an overview of the main drivers behind the current price increases and their near-term consequences.

Gas and coal prices have jumped to all-time highs, taking electricity prices with them

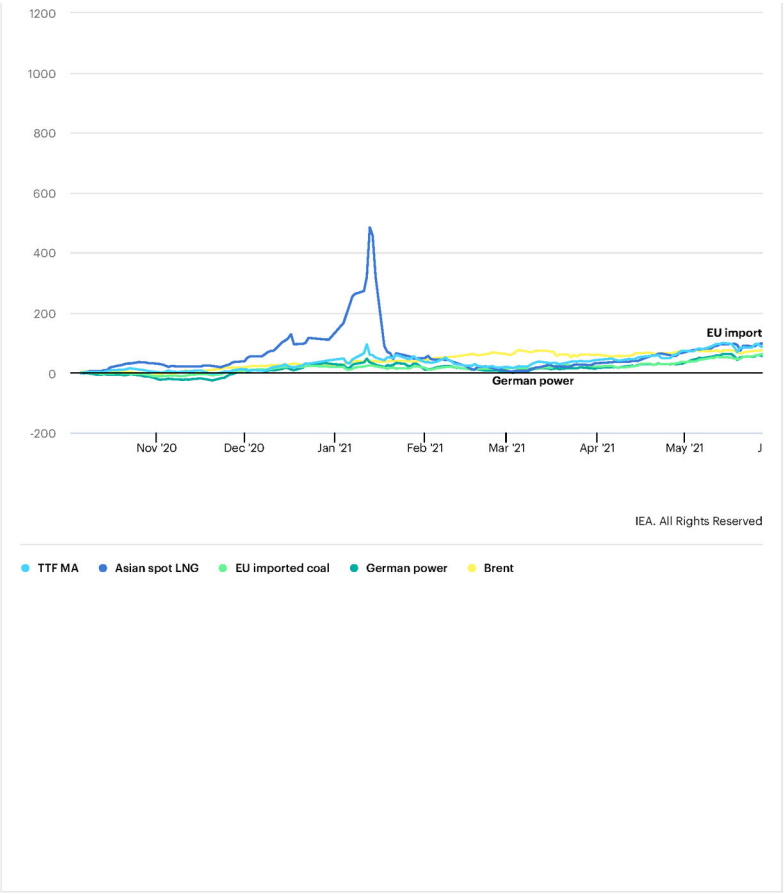
The historic plunge in global energy consumption in the early months of the Covid-19 crisis last year drove the prices of many fuels to their lowest levels in decades. But since then, they have rebounded strongly, mainly as a result of an exceptionally rapid global economic recovery (this year is on track for the fastest post-recession growth in 80 years), a cold and long winter in the Northern Hemisphere, and a weaker-than-expected increase in supply.

Natural gas prices have seen the biggest increase, with European and Asian benchmark prices hitting an all-time record last week – around ten times their level a year ago. US month-ahead natural gas prices have more than tripled since October 2020 to reach their highest level since 2008. International coal prices are around five times their level a year ago, and coal power plants in China and India, the world's two largest coal consumers, have very low stocks ahead of the winter season.

The strong increases in natural gas prices have prompted substantial switching to the use of coal rather than natural gas to generate electricity in key markets, including the United States, Europe and Asia. The increased use of coal is in turn is driving up CO2 emissions from electricity generation globally.

Evolution of energy prices, 2020-2021 Open

%



The higher gas and coal prices, combined with rising European carbon prices, have resulted in higher electricity prices. In Germany, electricity prices leaped last week to their highest level on record, up more than six times from a year ago. In Spain, where gas-fired power generation plays a larger role in setting electricity prices, the increase was even higher. In recent weeks, lower-than-expected wind generation has provided additional upward pressure.

Meanwhile, global oil demand continues to recover from its 2020 lows, and prices at the pump in many countries are at or near their highest levels in years. Companies around the world are expected to continue to draw on their oil stocks to help meet demand until the end of this year.

Consumers and businesses are feeling the squeeze

The price increases are expected to result in sharp upward pressure on household energy bills and also present broader risks to economic activity, especially for sectors that are directly exposed to the price rises. Many governments have taken measures to alleviate electricity bills, especially for vulnerable consumers.

In Europe, many businesses are likely to face the double impact of rising energy costs and a potential decline of consumer spending due to households' increased energy-related expenses. Rising power prices are already impacting operations of electricity-intensive industries. And several companies have

temporarily curtailed ammonia and fertilizer production, citing deteriorating margins due to the sharp increase in gas prices.

In China, rigid electricity tariffs have not followed the large increase in coal prices. As a result, coal power producers have insufficient coal on hand and rolling blackouts have occurred across two-thirds of Chinese provinces. Large energy-intensive industries – including steel, aluminium and cement – have been directed to cut production. The effect on global supply chains is not yet clear. In the northeast provinces of Heilongjiang, Jilin and Liaonin, even households are suffering power cuts, which is likely to have policy implications.

In India, the economic recovery and related increase in energy demand are causing a coal shortage. India's domestic coal mining, which accounts for 80% of the country's supply, has been unable to keep pace with demand, and higher international prices are making imports uneconomical. Power plants that rely on imported coal have slowed or even halted operations, and some plants that rely on domestic coal are starting to run out. Despite government efforts to address the shortages, several Indian states have suffered serious power shortages in recent days, affecting both residential and industrial customers.

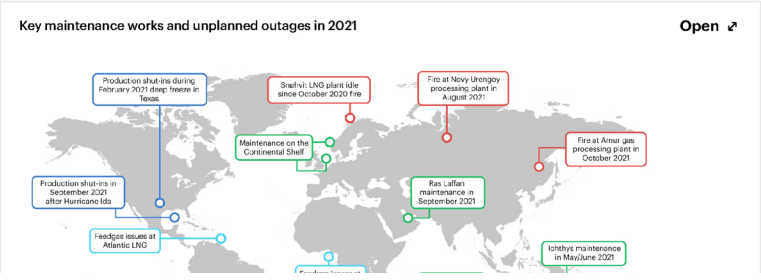
An energy crunch caused by a combination of factors – on both the supply and demand sides

The current high coal and gas prices are not the result of a single "shock event" on the demand or supply side. Rather, they result from a combination of supply and demand factors that gradually tightened markets over the course of several months and even years.

Investments in oil and natural gas have declined in recent years as a result of two commodity price collapses – in 2014-15 and in 2020. This has made supply more vulnerable to the sorts of exceptional circumstances that we see today. At the same time, governments have not been pursuing strong enough policies to scale up clean energy sources and technologies to fill the gap.

Against this backdrop, both coal and natural gas demand recorded strong gains across key markets in the first half of 2021 as the global economy rebounded. Initial estimates suggest that natural gas and coal consumption in these key markets increased by 8% and 11% respectively, compared with the first half of 2020. As well as the economic recovery, these rises were driven by a number of weather-related events, including a cold winter in the Northern Hemisphere, droughts that curtailed hydropower output in Brazil and elsewhere, and lower-than-average wind generation in Europe.

In terms of supply, both natural gas and coal have faced constraints. The Covid-19 lockdowns pushed some maintenance work from 2020 into 2021, which weighed on supply at a time when demand was recovering. The impact was particularly tangible in the UK and Norwegian areas of the North Sea Continental Shelf. In addition, unplanned outages at LNG liquefaction plants, upstream supply issues, unforeseen repair works, and project delays all further tightened the global gas market. The amount of global LNG supply affected by outages in the first nine months of 2021 was up by an estimated 27% compared with the average for the same period throughout 2015-2020 – with most of the outages unplanned. Russia's Gazprom, while honouring its long-term supply contracts, reduced its exposure to short-term sales and has not replenished its own storage sites in Europe to the levels seen in previous years. Gas supplies from the Groningen fields in the Netherlands, which are being closed in 2022, continue to be reduced as planned.





We estimate coal demand in China was up more than 10% in the first half of 2021 from the same period a year earlier, but coal production increased just over 5%, pushing up prices. With China by far the world's largest coal consumer and the price setter for global coal markets, international prices followed those in China. Disruptions among major exporters – in particular Indonesia, the world's largest thermal coal exporter, and to a lesser extent Australia and South Africa –pushed up prices further. High prices for natural gas, the main competitor of coal in power markets, also supported coal prices.

Temperature trends likely to set the tone for markets this winter

Due to strong demand growth and tighter-than-expected supply, European underground gas storage levels at the end of September were 15% below their five-year average levels. Low storage levels are expected to further increase Europe's reliance on gas imports through the heating season. In Brazil, the prolonged drought left the country's huge water reservoir levels 25% below their five-year average by the beginning of October, which could lead to further demand for LNG imports in the coming months. Prospects for the coal market, with low inventories ahead of the winter season not only in China but in all key consuming regions, are little better.

Current market dynamics (forward curves as of beginning of October) suggest that European benchmarks for natural gas (TTF) and coal (Rotterdam coal) will remain high, averaging USD 30/MBtu and USD 190/t through the 2021-22 heating season respectively.

Globally, the key drivers of energy market dynamics over the coming months will be the severity of the Northern Hemisphere winter, the strength of economic growth trends and the magnitude of unplanned supply outages. Prices of both natural gas and electricity will fluctuate in Europe depending on temperatures, wind output and many other factors. In this sense, weather conditions will affect markets from both the demand and supply sides. These fluctuations may be exacerbated by reduced natural gas storage levels, since these result in lower pressure levels that weigh on the ability to withdraw gas from storage sites during periods of high demand.

Responses should help consumers without hurting clean energy transitions

It is legitimate for countries to take emergency measures such as temporary relief from some taxes or charges to ease the burden on consumers, especially the most vulnerable, from periods of short-term market turmoil. But these measures should be implemented in such a way that they do not worsen the investment environment for low-carbon energy sources and technologies – such as renewables, energy efficiency, electricity grids, nuclear power and sustainable biofuels – which are vital for the transition to cleaner and more resilient energy systems.

The Energy Mix

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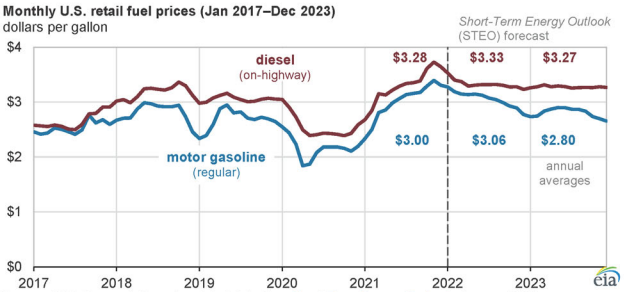
U.S. Energy Information Administration

Skip to sub-navigation

Today in Energy

January 13, 2022

EIA expects gasoline and diesel prices to fall in 2022 and 2023 as demand growth slows



Source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, January 2021

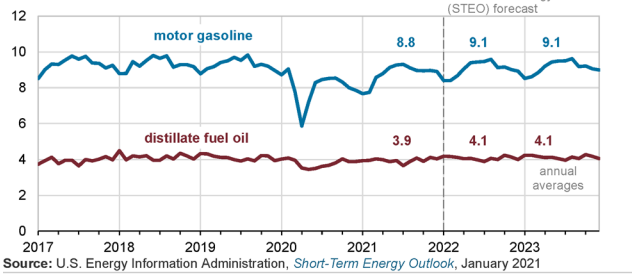
In our latest *Short-Term Energy Outlook*, we expect regular gasoline retail prices to average $3.06/gal in 2022, up from $3.00/gal in 2021, and then down to $2.80/gal in 2023. We expect on-highway diesel prices to increase to average $3.33/gal in 2022 before decreasing to $3.27/gal in 2023. In our forecast, annual average diesel demand reaches 2019 levels in the United States in 2022.

We expect that slower demand growth and increasing crude oil production through 2022 and 2023 will contribute to lower crude oil and petroleum product prices. Crude oil prices are the largest driver of retail gasoline and diesel fuel prices.

In 2022, we expect recently reduced retail gasoline prices to continue to decline as demand growth slows. We estimate that annual average motor gasoline consumption, which fell by an estimated 1.2 million b/d in 2020, increased by 0.7 million b/d in 2021. We expect an additional increase of 0.3 million b/d in 2022 and before a minor increase of less than 0.1 million b/d in 2023.

We expect U.S. gasoline consumption to remain below 2019 levels (9.3 million b/d) on an annual basis through the STEO forecast. However, we forecast that driving trends will surpass pre-pandemic levels in 2022 and 2023, but they will be offset by continued increases in vehicle fleet fuel economy that will limit U.S. growth in gasoline demand.

Monthly U.S. motor gasoline and distillate fuel oil consumption (Jan 2017–Dec 2023)
million barrels per day



Source: U.S. Energy Information Administration, *Short-Term Energy Outlook*, January 2021

Distillate fuel oil consumption (much of which is consumed as diesel) decreased from 4.1 million b/d in 2019 to 3.8 million b/d in 2020. In 2021, we estimate consumption increased to 3.9 million b/d. We expect distillate demand will return to just below 2019 levels in 2022.

Additional information on our forecasts for petroleum consumption, production, inventories, and prices is available in the *Short-Term Energy Outlook*.

Principal contributor: Kevin Hack

U.S. Energy Information Administration

GASOLINE EXPLAINED

GASOLINE PRICE FLUCTUATIONS

BASICS

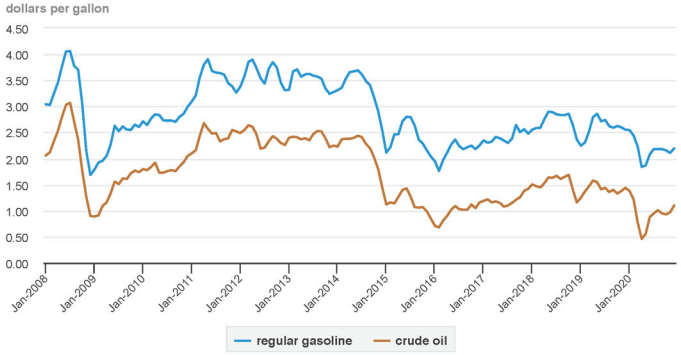
Why do gasoline prices fluctuate?

Retail gasoline prices are mainly affected by crude oil prices and the level of gasoline supply relative to gasoline demand. Strong and increasing demand for gasoline and other petroleum products in the United States and the rest of the world can place intense pressure on available supplies.

did you know?

Gasoline prices generally follow crude oil prices.

U.S average monthly gasoline and crude oil prices, 2008-2020



Source: U.S. Energy Information Administration, *Petroleum Marketing Monthly*, August 2021
Note: Regular gasoline price is the retail price including taxes for all formulations of regular grade gasoline. Crude oil price is composite refiner acquisition cost of crude oil.

Gasoline prices tend to increase when the available supply of gasoline decreases relative to real or expected gasoline demand or consumption. Gasoline prices can change rapidly if something disrupts crude oil supplies, refinery operations, or gasoline pipeline deliveries. Even when crude oil prices are stable, gasoline prices fluctuate because of seasonal changes in demand and in gasoline specifications.

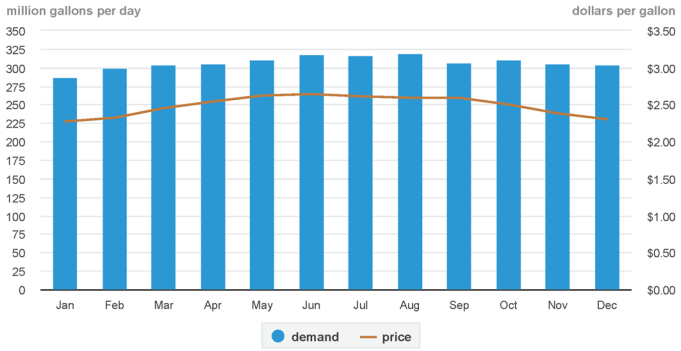
Crude oil and gasoline prices reached record levels in 2008

World crude oil prices reached record levels in 2008 as a result of high worldwide oil demand relative to supply. Significant growth in demand in China, the Middle East, and Latin America, combined with market uncertainty in world supply, contributed to the run-up in oil prices and, in turn, to record-high gasoline prices in the United States.

Seasonal demand and specifications for gasoline

Historically, retail gasoline prices tend to gradually rise in the spring and peak in late summer when people drive more frequently. Gasoline prices are generally lower in winter months. Gasoline specifications and formulations also change seasonally. Environmental regulations require that gasoline sold in the summer be less prone to evaporate during warm weather. This requirement means that refiners must replace cheaper but more evaporative gasoline components with less evaporative but more expensive components. In 2000 through 2020, the average monthly price of U.S. retail regular-grade gasoline in August was about 32 cents per gallon higher than the average price in January.

U.S. monthly average regular grade gasoline demand and retail price, 2000-2020

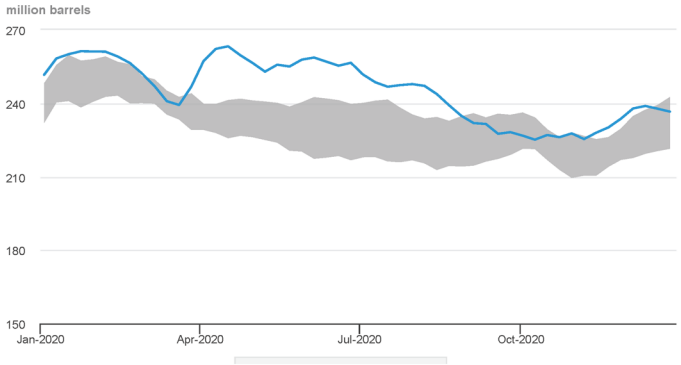


Source: U.S. Energy Information Administration, *Petroleum Marketing Monthly*, Prime Supplier Sales Volumes, August 2021, and *Gasoline and Diesel Fuel Update*

Gasoline inventories provide a cushion

The supply of gasoline is largely driven by crude oil supply and refining, imports of gasoline, and gasoline inventories (stocks). Stocks are the cushion between major short-term supply and demand imbalances, and stock levels can have a significant impact on gasoline prices.

U.S. weekly total gasoline stocks/inventories in 2020 and five-year range



If refinery or pipeline problems or reductions in imports cause unexpected declines in supply, gasoline stocks may drop rapidly. This drop in inventories may cause wholesalers to bid higher for available supply over concern that future supplies may not be adequate.

Imbalances may also occur when a region changes from one gasoline formulation to another, and refiners, distributors, and marketers adjust supply for the new product.

Last updated: September 9, 2021

Senator CARPER. All right. Let's ask some questions.

Ms. Wind, the past Administration's mismanagement of the Renewable Fuel Standard, along with the ongoing fuel impacts of the pandemic, have created volatile swings in compliance costs for the Renewable Fuels Program in recent years, making it hard for all stakeholders to plan and invest to meet the program's requirements. It is my understanding that Oregon has not experienced the same volatility in compliance costs with its Clean Fuels Program.

My question is this: How have the flexibilities built into Oregon's low carbon fuel standard, along with the additional cost containment and other measures within Oregon's program that differ from the Federal program, how do they help to mitigate compliance cost spikes?

Ms. Wind.

Ms. WIND. Yes, thank you for that question, Chair Carper. I think a lot of what is built into the program is the ability for the agency to monitor the costs. We do, of our neighboring States in comparison to the State of Oregon, we do routinely track the fuel retail and wholesale prices of fuels that are delivered in California and Washington, and in Idaho.

For the past years that we have been operating the program in Oregon, we have not seen a significant increase in comparison to those States. Those are States that also don't necessarily, in the State of Idaho, don't have any kind of additional fuel standards.

We do keep track of those prices, and we are legislatively required to have cost containment mechanisms in the program to be able to monitor those fuel prices. I think it is a combination of the monitoring and the cost containment mechanisms that have not caused these large volatilities in the fuel prices in Oregon.

Senator CARPER. All right, thanks a lot. Just a quick follow up: It is my understanding that Oregon tracks consumer fuel costs and the surrounding States' consumer fuel costs as part of its implementation of the low carbon fuel standard. Very briefly, are there surrounding States that do not have a low carbon fuel standard today that have higher fuel costs than Oregon?

Ms. WIND. Thank you for that question, Chair Carper. As I previously stated, in the most recent analysis of the data that we have been looking at, we do compare our fuel prices, both retail and wholesale, to the States of Washington and California and Idaho. It is noted that our fuel prices in Oregon have shown that we are lower than even the State of Idaho.

The State of Idaho does not have any additional fuel regulations. They don't have a low carbon fuel standard in place there. We feel confident that the prices of the fuels in Oregon are not being disproportionately impacted by the fact that we do have a low carbon fuel standard.

Senator CARPER. All right, thanks for that.

One question for Ms. Skor, if I could, on E15 and advanced biofuels.

Ms. Skor, recent court decisions prevent the sale of fuels that have blends of ethanol to 15 percent, known as E15, this coming summer, unless Congress or the Administration takes some further action. At the same time, EPA, over the course of several different

Administrations has been slow to approve advanced biofuel applications for new pathways and fuels for the Renewable Fuel Standard.

The question is this: In your mind, would the approval of additional advanced biofuel applications and Congress acting to allow E15 to be sold year round help mitigate some of the volatility in the renewable fuel program costs that we are seeing today?

Ms. SKOR. Thank you, Chairman. It most certainly would. The easiest path to bring down the price of the RIN is to blend more biofuel. It is basic supply and demand. The more biofuels blended, in particular higher blends like E15, the more RINs created. That is how you bring down the price of the RIN.

Not only will it address the stated cost, but you are also going to be introducing a lower cost fuel into the fuel supply for consumers, and there are also technologies languishing in EPA that I have got producers currently producing cellulosic ethanol. They are not getting credit for it, because the application has been sitting around for 5 years.

There is more innovation that we can do to bring low cost, low carbon fuels to the table, but we do need some certainty and some predictability and for the regulations to keep up with the marketplace and the innovation.

Senator CARPER. All right. I have plenty more questions, but I am going to yield, at this point, to Senator Capito. Thank you for those responses.

Senator CAPITO. Thank you, Mr. Chairman.

Ms. Koch, in your remarks, you were pretty clear about the small refinery exemption. Obviously, I mentioned that in my opening remarks, my concern. You are probably aware of the case that I brought forward of Ergon in West Virginia, who has two favorable court decisions from the Fourth Circuit.

Shouldn't EPA take into consideration that our courts have actually taken into consideration making regulatory decisions, and that this was causing hardship to this small refinery? How would you respond to EPA's blanket denial of everything, when the courts have actually come forward and said it is not a sound decision?

Ms. KOCH. Yes, Senator Capito. You are exactly right. For the 2016 to 2018 compliance years, the Fourth Circuit Court of Appeals vacated and remanded EPA's decision to deny hardship relief to Ergon West Virginia. Ergon runs about 23,000 barrels per day. It is truly one of the smallest refineries in the country. And the court summarily rejected EPA's decision because EPA did not consider the facts of Ergon's specific case: Its location, how it distributes its fuels, the fact that 70 percent of its then production was diesel, and it remanded to EPA.

EPA then took another shot at Ergon and again, denied Ergon's petition, even though it had been vacated and remanded by the court, and again, determined that Ergon was ineligible. The second time, the Fourth Circuit vacated EPA's decision again, this time, finding that EPA had been arbitrary and capricious in treating Ergon differently than any other small refinery.

Now, this is the third attempt to prevent Ergon West Virginia from receiving hardship relief. Essentially, what EPA is proposing to do is Ergon and every other small refinery in the United States will be denied hardship relief.

If EPA proceeds on this path, ironically, on the basis that every refinery in the United States, from the largest multinational oil company to the tiniest, small refinery in Newell, West Virginia, has exactly the same cost of compliance. It doesn't matter that a large, integrated oil company can export. It doesn't matter that a large, integrated oil company has excess RINs and makes millions in speculation. Everybody's cost is the same.

I always go back to the DOE study prepared for Congress, which explains the hardship that small refineries will suffer as a result of their inability to blend, as a result of their inability to take massive amounts of capital and joint venture. So yes, you are correct, Senator, that this is the third attempt to divest Ergon of relief.

Senator CAPITO. Right. We specifically in the law made provisions for a small refinery exemption, correct?

Ms. KOCH. Specifically made provisions for each petition to be decided on its merits, that is correct.

Senator CAPITO. Right, thank you.

Mr. Pugliaresi, your last chart, I was looking through your charts, because we have them in our book, talks to me about where we see gas prices going and who really gets hurt the most. This talks about the rising costs of transportation fuels harm low income and many minority communities. We know that if you have to pay an extra $10 to $15 to fill your car up, that hits that person that, at the end of the month, is looking for an extra $10 or $15 to help pay their electric bill or some other bill that is also rising at the same time.

You talked about the cost of blending is about 28 to 30 cents per gallon, so there is a cost there. You also mentioned to me earlier, before we got started, that you think, as we are moving forward, there are some guardrails that EPA needs to have as we are moving forward, that we could provide for them.

If you want to talk about that issue, I would like to hear that, but I would also like to hear your opinion on the overall cost of what we see now, the high cost of gasoline and how we can deal with this issue of who is hitting it the hardest, and how it can move. There are proposals out here to get rid of the gas tax, but that is 18 cents. That is not even close to this.

Mr. PUGLIARESI. First, let's talk a little bit about the sort of government mandated energy transition, because we are the largest oil and gas producer in the world. We are very concerned that certain policies are now seeking to constrain the North American production platform before the alternatives are ready.

We are going to produce a lot of EVs; we are going to produce a lot of alternative fuels and technologies, but if we proceed with—between 2010 and 2020, the United States alone, plus the application of biofuels, provided over 80 percent of world increases in demand for liquid fuels. That is the first thing we need to think about.

We should treat this North American production platform as a strategic and economic asset. We should be very careful before we decide to disrupt it. That is the biggest incentive, the biggest program we have to keep gas prices under control.

The next thing is that we are fighting over a small volume. Because in the absence of a mandate, we would still be blending any-

where from 8 to 10 percent. Ethanol is a valuable feedstock. It helps to meet octane requirements, and other biofuels, but if we proceed with a mandate, we kind of prohibit innovation and alternatives to come forward. We have no idea what the fuels of the future really are going to look like.

Your final point, this is devastating for low income communities, as you can see from that chart. Everyone who wants to proceed with these exotic fuels of the future should keep in mind that I don't believe the American people will react very positively if we go into a period of sustained high gasoline prices.

Senator CAPITO. Thank you.

Thank you.

Senator CARPER. All done? OK. All right, thanks so much, Senator Capito.

Senator Cardin was here earlier. He is now joining us, I think, by Webex remotely.

Senator Cardin, if you are there, please proceed with your questions. Thanks for joining us.

Senator CARDIN. Well, thank you, Chairman Carper. I appreciate this very much.

This hearing is long overdue. The history of the Renewable Fuel Standards is something that needs to be understood, and we need to update this, so I very much appreciate your leadership on these issues. There are many competing priorities. We have energy security issues, we have the environment and our concerns for climate change. We have the cost issues, that we have just talked about.

By the way, there are lots of governmental subsidies in regard to energy that affect the cost issues, not just here. And then the food stock.

I would like to get the view from our members of the panel as to what we can do if we want to focus on development and growth of domestic advanced biofuels derived from non-food based food stocks. How should we be adjusting our policy in regard to renewable fuel standards?

Mr. PUGLIARESI. I think the way to do this is to allow a lot of alternative biofuels to compete in the marketplace for the liquids market. And for those fuels which have a lot of promise and for which we think are substantial public, long term public benefits, we should have a good research and development program, even some support for, probably, deployment.

But in the end, we should allow a large opportunity for consumer choice and for competition to take place between manufacturers or processors of fuel to deploy these into the marketplace.

Ms. SKOR. I will go ahead, and I will follow on those themes of choice and competition, two themes that we wholeheartedly support. When it comes to choice, consumers do need choices. They need options at the pump. It is very unfortunate that come June 1st, one of the lowest carbon, low fuel, low cost options available to them is going to be eliminated because a few refineries sued and won in court.

So we have to reintroduce higher blends of biofuel, year round access to E15. That is giving consumers one low cost choice.

When it comes to competition, as we all pursue lower carbon intense energy, that is very important. Critical to that is making

sure that the modeling, that the standards, that the incentives, the performance standards, are technology neutral. In this country, let the best win, right? So, let's make sure that we are looking at the full life cycle analysis of all of the technologies and all of the available solutions.

We are going to need everything to be able to achieve these ambitious climate goals, so make sure that the modeling reflects up to date science, it reflects innovation taking place within agriculture to bring down carbon intensity, and then I think you are going to have a competitive environment with choice for consumers.

Senator CARDIN. I would just mention in that regard, Senator Carper and I both serve on the Senate Finance Committee. We have looked at proposals to try to have it neutral in regards to the tax issues and reward those that are lower in carbon emissions and help our environment. We agree with that.

The problem is that today's structure does reward certain high carbon sources, and we really don't have a level playing field. I don't know if the other panelists want to respond on this or not.

Ms. WIND. Yes, thank you for the question. This is Cory-Ann Wind.

I think this is, what I would say is that, so this is what the core of a low carbon fuel standard does, and so it really does reward the carbon intensity of that fuel.

As you mentioned, going from a crop based fuel to a waste oil for biodiesel, for example, the fact that they do have lower emissions means that they do have higher incentives in a low carbon fuel standard. Those higher incentives actually bring down the cost of those fuels.

That is how it is scored in a low carbon fuel standard, and I think it has been working really well to incent the lowest of the lowest carbon fuels.

Senator CARDIN. That is some of the debate we are having now on the price of carbon. If we had a true price of carbon, I think we would have a fair competitive standard, giving choice to the consumer.

Thank you, Mr. Chairman.

Senator CARPER. Thank you, Senator Cardin.

Before we turn to Senator Inhofe, I want to ask unanimous consent to submit for the record various materials demonstrating recent strong economic growth, including a statement from the Assistant Secretary for Economy Policy at the Department of the Treasury from January 31st, 2022. According to this statement, real GDP grew 5 and a half percent over the four quarters of 2021, the fastest annual pace in, get this, 37 years. This is in addition to the materials I submitted earlier, which show energy prices today are still lower than they were in 2007, and today's prices at the pump are driven by growth in fuel demand as the economy emerges from the pandemic.

Without objection.

[The referenced information follows. Due to size constraints some documents are not included below but are available in Committee files.]

U.S. DEPARTMENT OF THE TREASURY

Economy Statement by Benjamin Harris, Assistant Secretary for Economy Policy, for the Treasury Borrowing Advisory Committee January 31, 2022

January 31, 2022

Real GDP growth accelerated in the fourth quarter of 2021, returning to a pace consistent with that seen in the first half of the year. Economic growth this quarter was driven primarily by inventory investment—as firms restocked depleted inventories—as well as strong export growth and robust consumer spending on services. By the end of 2021, household balance sheets were exceptionally healthy due in part to the American Rescue Plan (ARP), other government pandemic assistance, and brisk wage growth. The pace of GDP growth in the fourth quarter ended 2021 on a historic note: over the four quarters of 2021, real GDP grew 5.5 percent, the fastest annual pace in 37 years.

Over the course of 2021, the labor market approached full employment. Over the twelve months ending December 2021, the economy enjoyed the greatest number of jobs gained on record and the fastest calendar year drop in the unemployment rate. In this environment, workers were able to leverage a high degree of job mobility to achieve strong wage gains—most notably in low-wage sectors.

A mismatch between supply and demand led inflation to rise substantially in 2021 as energy demand recovered to pre-pandemic levels, goods demand remained high, and supply chains experienced disruptions due to the rapid recovery in demand and Covid impacts on manufacturing supply chains. By the end of the year, principal measures of total and core inflation climbed to multi-year highs. While the inflation outlook is uncertain, a receding pandemic, weaker demand for goods, and easing supply bottlenecks can be expected to reduce inflationary pressure throughout the year.

GDP GROWTH

According to the advance estimate released last week, real GDP growth accelerated sharply to 6.9 percent at an annual rate in the final quarter of 2021, following a 2.3 percent gain in the third

quarter. Given the robust pace of growth in the fourth quarter, GDP at the end of 2021 was 5.5 percent higher on a year-over-year basis, the strongest annual pace since 1984.

Real private domestic final purchases (PDFP)—the sum of personal consumption, business fixed investment, and residential investment—grew 2.8 percent at an annual rate in the fourth quarter, after increasing 1.4 percent in the third quarter. PDFP growth in the second half of 2021 was slower than in the first half—in the first quarter, PDFP surged by 11.8 percent and by 10.1 percent in the second. By this measure, demand has returned to pre-pandemic trend.

Real personal consumption expenditures (PCE)—the largest component of PDFP and roughly two-thirds of real GDP—rose by 3.3 percent in the fourth quarter on an annualized basis, accelerating from the 2.0 percent gain in the third quarter. The fourth-quarter print reflected continued rotation of consumption from goods to services. Real purchases of durable goods increased just 1.6 percent in the fourth quarter—held down by reduced purchases of motor vehicles and household durable items – while nondurable goods PCE ticked down by 0.1 percent. Expenditures on services increased by 4.7 percent in the fourth quarter, propelled by higher spending on health care and strong recovery in pandemic-sensitive sectors, such as recreation and transportation services. Despite the rotation toward pre-pandemic consumption patterns, the composition of PCE remains weighted more heavily toward goods than services—as of the fourth quarter of 2021, PCE goods was still 15.4 percent higher than just before the pandemic while PCE services was 0.4 percent lower.

Business fixed investment (BFI) increased by 2.0 percent at an annual rate in the fourth quarter, following a 1.6 percent gain in the third quarter. Investment in structures continued to be a drag on BFI growth, dropping by 11.4 percent in the third quarter. Investment in mining-related structures, including oil and gas wells, rose in the fourth quarter as rising oil prices made domestic rigs more profitable. Meanwhile, both equipment investment and investment in intellectual property products increased in the fourth quarter—by 0.8 percent and 10.6 percent, respectively.

Real residential investment—the third and final component of PDFP—slipped by 0.8 percent at an annual rate in the fourth quarter, the third consecutive quarterly decrease. Rising construction prices were partly responsible for the decrease in real investment. Although nominal residential spending rose 8.6 percent on an annualized basis, the price index for residential construction jumped by 9.5 percent. Higher construction costs have been driven in part by shortages of materials and labor. However, residential investment remains well above pre-pandemic trend.

The change in private inventories (CIPI) was the strongest contributor to real GDP growth in the fourth quarter, adding 4.9 percentage points. Unlike in the third quarter, the impetus to GDP growth from CIPI was due to inventory build-up, rather than slower inventory draw down. During the pandemic, inventories have been depleted to historically-low levels. Between the first quarter of 2020 and the third quarter of 2021, total real private inventories were drawn down by over $81 billion (not annualized). The increase in the fourth quarter recovered only about half of the loss. However, inventories for some industries remain very lean despite buildup in the fourth quarter, such as retail motor vehicle inventories which recovered only 7 percent of the net drawdown since the beginning of the pandemic. That is, inventories are stretched, and restocking needs have extended into the current year.

The trade deficit widened by $21.4 billion to $1338.0 billion in the fourth quarter; a change that neither added nor subtracted from GDP growth. Total imports of goods and services jumped 17.7 percent at an annualized rate, while total exports of goods and services jumped 24.5 percent. Over 60 percent of the increase in services exports was due to the return of international travel to the United States.

Total government spending declined 2.9 percent at an annual rate in the fourth quarter, after rising 0.9 percent in the third quarter. A 4.0 percent decline in federal spending drove the overall pull-back, largely reflecting fewer purchases of defense-related intermediate goods. State and local government consumption was down 2.2 percent at an annual rate in the fourth quarter; the decrease reflected lower real spending on compensation for state and local government salaries as well as less real investment in structures—which was significantly affected by rising construction costs.

In sum, real GDP accelerated to 6.9 percent in the fourth quarter on an annualized basis. The acceleration primarily reflected sizeable contributions from a private inventory build (4.9 percentage points) as well as increased consumer spending (2.3 percentage points) and business fixed investment (0.3 percentage points). Government consumption and investment was the sole significant drag on fourth quarter growth (-0.5 percentage points).

LABOR MARKETS AND WAGES

The economy made impressive strides in 2021 in generating payroll jobs and in reducing headline as well as broader measures of unemployment. Over the twelve months ending December 2021, the economy generated 6.5 million payroll jobs, the largest number of jobs added in a single year on record. Over the same period, the headline unemployment rate

dropped 2.8 percentage points to 3.9 percent as of December. The broadest measure of labor market slack, the U-6 unemployment rate, fell by 4.4 percentage points over the year to 7.3 percent in December 2021—also the sharpest decrease on record and ending the year only 0.3 percentage points above the pre-pandemic level in February 2020. The long-term (27 or more weeks) unemployment rate has declined rapidly to 1.2 percent of the labor force in December 2021, falling by half over the previous 12 months.

These rapid improvements have translated into tight labor market conditions, which have put upward pressure on nominal wages. Nominal average hourly earnings for production and non-supervisory workers increased 5.5 percent over the year through December 2021. The Employment Cost Index (ECI), which better controls for changes in labor composition and is a more comprehensive measure of total compensation, showed private sector wages increasing 5.0 percent over the four quarters ending in December 2021, roughly double the 2.8 percent gain over the four quarters ending December 2020, and the fastest four-quarter wage gain since the first quarter of 1984. Lower wage occupations and industries continue to see the fastest growth in wages. In leisure and hospitality industries, the ECI for private wage growth jumped 8.9 percent over the year ending in the fourth quarter of 2021, while the retail trade ECI was 7.0 percent higher.

Unlike in 2020 and early 2021, wage gains in the past several months have been driven by tight labor markets and churn rather than compositional effects. Recovery in the prime-age (ages 25 to 54) labor force participation rate has been incomplete, with the participation rate ranging between 81.6 percent and 81.9 percent—well below the pre-pandemic participation rate around 83 percent. At the same time, the participation rate for those older than 55 years may have shifted lower permanently. Population growth has also stalled in the last two years with substantially lower immigration and significant Covid mortality impacts.

These factors have left labor supply constrained and increased the ability of workers to negotiate for wage gains or move to higher-paying jobs. As evidence, the Job Openings and Labor Market Turnover Survey (JOLTS), typically thought to convey worker confidence in finding employment, showed quits rising to a record-high 4.5 million in November, equivalent to 3.0 percent of employment. Prior to the pandemic, the series' high quits rate was 2.4 percent

PRICES

Inflation picked up markedly in 2021. Some of the factors were largely anticipated. Given the sharp drop in energy prices at the beginning of the pandemic in 2020, any recovery of global

prices would spur headline inflation in 2021. Similarly, rising house prices due to high demand were likely to filter into shelter inflation; the re-opening of pandemic-sensitive services would mean higher sector-specific prices.

However, other factors were unanticipated. Energy inflation was further exacerbated by a global energy shortage due to cutbacks in production at the start of the pandemic. High household savings and the slow re-opening of services due to new variants delayed the rotation of demand from goods to services. In addition, the pandemic constrained supply chains as international ports shuttered with outbreaks and domestic labor supply was unable to fully meet high demand.

In the fourth quarter of 2021, the Consumer Price Index (CPI) for all items rose 0.9 percent in October before slowing to 0.5 percent growth in December. Over the 12 months through December 2021, headline CPI rose 7.1 percent while core CPI inflation—which excludes food and energy prices—registered 5.5 percent. Energy price growth accounted for 1.5 percentage points of headline CPI inflation, while food inflation added 0.9 percentage points. Inflation from durable goods was led by motor vehicles, which added 1.2 percentage points to growth as high demand and a shortage of semiconductors for motor vehicles reduced production and pushed up prices. For core services, shelter costs contributed 1.2 percentage points to year-over-year inflation. Re-opening effects from pandemic-sensitive services were relatively mild, contributing only 0.3 percentage points to headline inflation in 2021.

Over the same period, the PCE price index rose 5.8 percent while core PCE inflation was 4.9 percent in 2021. Although the CPI and PCE indices have different methodologies and weighting for components, the PCE price index showed similar drivers of inflation.

HOUSING MARKETS

Throughout 2021, housing markets were marked by an imbalance between supply and demand, driving rapid home price growth and eroding affordability. The Case-Shiller national house price index—which measures sales prices of existing homes—was up 18.8 percent over the year ending in November 2021, a sharp acceleration from the 9.5 percent and 3.4 percent rates seen in November 2020 and November 2019, respectively. Moreover, in each of the past seven months, year-over-year increases this index have run between 17 percent and 20 percent.

In the fourth quarter, however, there were positive signs for housing supply in coming quarters. Single-family housing starts rose by a combined 9.8 percent from September to December 2021, and single-family permits, which signal future starts, have increased by 8.4 percent over the same period. In 2019 and 2020, construction of a new single-family home took about eight months from authorization to completion (the estimated time-to-completion is not yet available from the Census Bureau), suggesting fresh supply will come on to the market in 2022 and ease some house price pressures. Indeed, the number of homes under construction at the end of 2021 is the highest since 2007. Moreover, surveys of homebuilders reflect optimism about the state of the housing market. The National Association of Home Builder's confidence index rose for the fourth consecutive month in December, ending the year at 84, just 6 points shy of record high reached in November 2020.

Meanwhile, sales of homes trended lower at the end of 2021. In December, existing home sales —which account for 90 percent of all home sales—declined 4.6 percent over the month and were down 7.1 percent over the year. Although new single-family home sales rose by 11.9 percent in December, the level of sales was still down by 14.0 percent over the year. One net, existing and new home sales were lower by around 600,000 over the year ending December 2012. The downtrend of existing home sales reflected in part very lean inventories. At the end of December 2021, existing home inventories dropped to an all-time low of 910,000, dropping by 14.7 percent over the year and equivalent to 1.8 months of sales. (Realtors consider a seven-month supply to be a balanced market.) By contrast, the inventory of new single-family homes available for sale has moved closer to a balanced market. Inventories of new homes rose by 34.8 percent over the year to 403,000, equivalent to a 6.0-month supply.

RISKS TO THE OUTLOOK –

There are multiple downside and upside risks to the economic outlook. Primary among the downside risks are concerns about the pandemic, supply chains, energy prices, and shelter costs.

Pandemic: Since the previous Economy Statement to the Treasury Borrowing Advisory Committee, the Omicron variant was identified in South Africa and quickly spread to the United States. Although symptoms and deaths from Omicron appear to be less severe than from previous variants, it also appears to be more effective than previous variants at evading the immunity from vaccination or previous infection. According to the most recent data, the seven-day average of COVID infections due to Omicron

peaked in mid-January above 800,000 cases, causing significant labor absences as sick workers stayed home. Future variants may have worse symptoms and fatality rates or may be fully resistant to current vaccines and present a significant risk to the economic outlook. On the other hand, given the level of vaccinations and prior infection, the US population may be nearing herd immunity.

The persistence of the pandemic endangers the recovery of supply-chains, which poses risk to production and inflation. Continued lockdowns in China or southeast Asia may result in delays or further reducing production, keeping goods prices elevated. Omicron could further disrupt shipping or transportation chains, resulting in price pressures.

The pandemic has also negatively affected labor supply and population growth. To date, labor supply from the elderly has likely permanently shifted lower due to pandemic-related early retirements. Some people's work preferences may have changed due the new normal of pandemic-era work, while others may have stepped away from work due to other factors, such as limited availability of childcare. If these losses in labor supply are permanently lost due to the pandemic, then potential economic growth has been shifted lower.

Energy prices: Energy producers—including the United States—have been slow to recover the production lost in 2020. Members of OPEC+ have fallen behind production targets and the Energy Information Agency expects that domestic production in 2022 will trail pre-pandemic production by roughly 500,000 barrels per day. Currently, it is expected that energy prices will stabilize in 2022, but geopolitical instability could result in higher energy prices.

Shelter costs: House prices and rents are out of sync. Since owning a home and renting an apartment are imperfect substitutes, prices and rents tend to be in long-run equilibrium. Yet given current house valuations, the price-to-rent ratio has risen sharply to 1.5, an historically high ratio, up from suggesting an imbalance between types of shelter.

While there is the potential for negative shocks to the economy, some developments imply the potential for strong GDP growth, an easing of labor market tightness, or decreased inflationary pressures.

Household finances: In 2021, household balance sheets were in healthy positions. Even as pandemic assistance waned in the second half of the year, personal income continued to rise largely due to strong wage and salary growth. By the third quarter of 2021 (last available data), households' net worth stood at a record-high of 796 percent of disposable personal income

(DPI), nearly 40 percentages from the end of 2020. At the same time, debt service as a share of DPI remained about 70 basis points below pre-pandemic norms.

Structures investment: Energy, commercial, and residential investment all have upside potential. High energy prices would continue to spur structures investment in oil- and gas-related mining structures, while a quicker return to in-person work may help relieve the overhang in commercial properties and speed re-investment in the sector. Meanwhile in housing markets, the high number of units permitted, units authorized but not yet started, and units under construction bode well for residential investment in the coming year.

State and local governments: At the beginning of the pandemic and heading into 2021, state and local governments reportedly worried about their finances following the wide-spread stay-at-home orders. Due to the ARP and stronger-than-expected recovery in revenues, fiscal balances are in solid shape. At the end of the 2021 fiscal year (ending June for the vast majority of state governments), state budget officers preliminarily reported that state general funds roughly tripled to $153 billion while rainy day funds rose by 47 percent to $113 billion. They also projected that general fund spending will increase by 9.5 percent from fiscal years 2021 to 2022, indicating the potential for state and local spending to be a key contributor to GDP growth, in stark contrast to the experience after the 2008 recession.

CONCLUSION

As of December 2021, the economic expansion is in its twentieth month. Real GDP growth accelerated in the fourth quarter to 6.9 percent at an annual rate, bringing growth over the four quarters of 2021 to a historically strong 5.5 percent. At the start of 2022, key investment sectors are poised for strong growth, despite ongoing supply chain difficulties and the specter of new COVID variants. Private forecasts of GDP growth predict a return to trend GDP late this year, whereby the level of GDP reaches the level it would have been absent the pandemic-induced recession. As of early January, before the release of the advance estimate for Q4 GDP, private forecasters projected growth in real GDP of 3.3 percent in the first quarter of this year. On a fourth-quarter over fourth-quarter basis, private projections put real GDP growth at the end of 2022 at 3.3 percent

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Macro Matters

U.S. labor market shrugs off Omicron surge, economy strong ahead of rate hikes

By Lucia Mutikani

5 minute read

Summary

Nonfarm payrolls increase 467,000 in January

My View

Employment gains spread across all industries

Economy created 709,000 jobs in December and November

Unemployment rate at 4.0%; participation rate at 62.2%

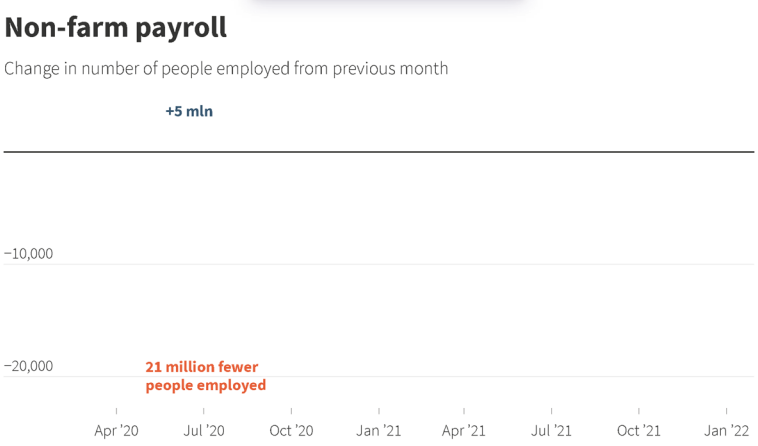
Average hourly earnings rise 0.7%; up 5.7% year-on-year

WASHINGTON, Feb 4 (Reuters) - The U.S. economy created far more jobs than expected in January but despite the disruption to consumer-facing businesses from a surge in COVID-19 cases, pointing to underlying strength that should sustain the expansion as the Federal Reserve starts to raise interest rates.

The Labor Department's closely watched employment report on Friday also showed a whopping 709,000 more jobs were added in November and December than previously estimated. Wage gains accelerated last month and the labor pool expanded.

The upbeat report ended days of anxiety among economists and White House officials who had frantically tried to prepare the nation for a disappointing payrolls number.

"This is a strong jobs report," said Chris Low, chief economist at FHN Financial in New York. "The odds of quelling inflation without a recession look better today than yesterday."



Source: Thomson Reuters Datastream

Nonfarm payrolls increased by 467,000 jobs last month, the survey of establishments showed. Economists polled by Reuters had forecast 150,000 jobs would be added in January. Estimates ranged from a decrease of 400,000 to a gain of 385,000 jobs.

Employment is 2.9 million jobs below its pre-pandemic peak.

Part of the broad increase in payrolls likely reflected low layoffs after the holiday hiring season, with 10.9 million job openings at the end of December. Though the drop in actual employment in January was in line with prior years, there were large differences at the industry level.

The government also reported that 374,000 more jobs were created in the 12 months through March 2021 than previously reported. January capped President Joe Biden's first year in office, which saw 6.6 million jobs added. Despite the strong economy, Biden's popularity is declining amid soaring inflation.

"We still have a lot of work to do," said Biden at the White House. "Making sure every American has a job, it's a great start, but it's not the finish."

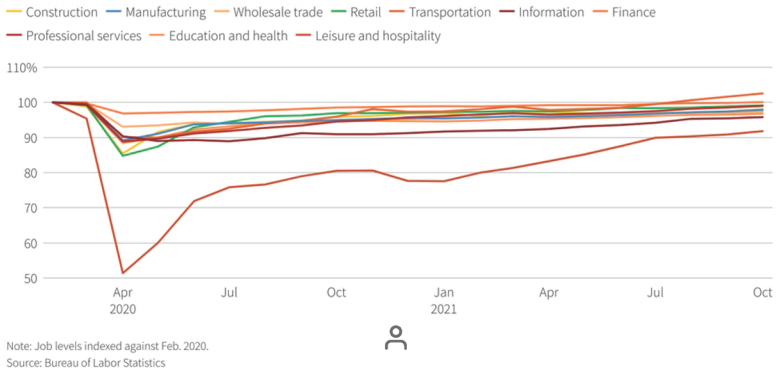
The labor market resilience could alter expectations that economic growth would slow significantly in the first quarter, after consumer spending exited 2021 with a whimper. The economy grew at a 6.9% annualized rate in the fourth quarter. Growth estimates for the first quarter are below a 2% pace.

Strong employment gains, accompanied by the biggest annual increase in wages since May 2020, pave the way for the U.S. central bank to raise interest rates in March by at least 25 basis points to tame high inflation. Economists expect as many as seven rate hikes this year.

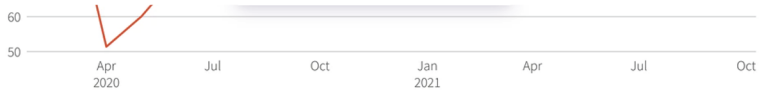
"The report is unequivocally good for the economy, but not for markets as the strength in the numbers presents another data point which supports more aggressively hawkish Fed action," said Cliff Hodge, chief investment officer at Cornerstone Wealth in Charlotte, North Carolina.

Jobs by industry

The recovery has been slowest in the leisure and hospitality industry where early job losses were steepest. But it has turned higher in recent months.



Note: Job levels indexed against Feb. 2020.
Source: Bureau of Labor Statistics



Note: Job levels indexed against Feb. 2020.
Source: Bureau of Labor Statistics

Reuters Graphics Reuters Graphics

LABOR POOL EXPANDS



People wait in line to enter the Nassau County Mega Job Fair at Nassau Veterans Memorial Coliseum in Uniondale, New York October 7, 2014. REUTERS/Shannon Stapleton/File Photo

Economists had anticipated a weak jobs report as the government surveyed businesses for payrolls in mid-January, when Omicron infections were peaking. The Labor Department said a record 3.616 million people who had a job were absent during the survey week because of illness.

Workers who are out sick or in quarantine and do not get paid during the payrolls survey period are counted as unemployed in the establishment survey even if they still have a job. Lower-paid hourly workers in industries like healthcare as well as leisure and hospitality, who typically do not have paid sick leave, bore the brunt of the winter COVID-19 wave.

According to the latest government data, paid sick leave was available to 79% of civilian workers in March 2021.

The leisure and hospitality industry added 151,000 jobs in January. Healthcare employment increased by 18,000. There were gains in retail, professional and business services employment as well as transportation and warehousing, and wholesale trade.

Manufacturing payrolls rose by 13,000, but construction employment fell 5,000, likely because of freezing temperatures. Government payrolls increased by 23,000 jobs.

Employment could increase further as coronavirus infections continue to subside. First-time applications for unemployment benefits **dropped for a second straight week** last week.

The United States is reporting an average of 354,399 new COVID-19 infections a day, sharply down from the more than 700,000 in mid-January, according to a Reuters analysis of official data.

The government introduced new population estimates for the household survey, from which the unemployment rate is derived. The new assumptions had a negligible effect on the unemployment

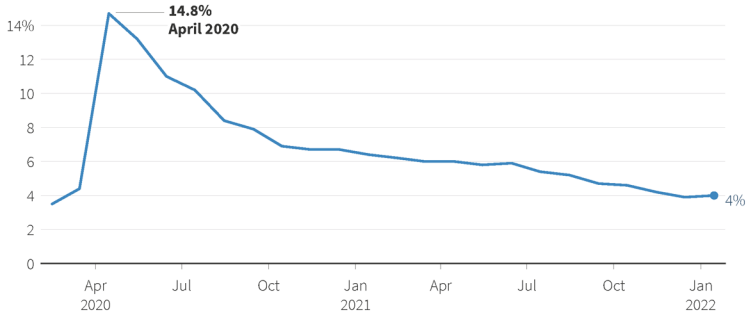
rate, which rose to 4.0% from 3.9% in December.

But the labor force participation rate, or the proportion of working-age Americans who have a job or are looking for one, increased to 62.2% due to the changes in the composition of the population, from 61.9% in December.

The workforce increased by 1.393 million people. The employment-to-population ratio rose to 59.7% from 59.5% in December.

Unemployment rate

Rate of unemployment since the start of the Coronavirus pandemic in Feb. 2020



Source: Thomson Reuters Datastream

Other details of the household survey were strong. Employment increased by 1.199 million jobs. The survey counts people who have a job as employed regardless of whether they got paid during the survey week if they were temporarily absent from their jobs because of illness or other reasons.

A broader measure of unemployment, which includes people who want to work but have given up searching and those working part-time because they cannot find full-time employment, dropped to 7.1%, the lowest since February 2020, from 7.3% in December.

With some lower hourly paid workers at home, wage growth accelerated. Average hourly earnings surged 0.7%, which raised the annual increase to 5.7%, the largest gain since May 2020.

But Omicron's surge cut the average workweek to 34.5 hours, the shortest since April 2020, from 34.7 hours in December.

"All in all, the U.S. economy appears to be on a strong footing," said Noah Williams, an adjunct fellow at the Manhattan Institute.

Reporting by Lucia Mutikani Editing by Andrea Ricci, Chizu Nomiyama, and Paul Simao

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My View Following Saved

Union Jobs in Ethanol & Biodiesel Industries: An American Success Story

Study and Analysis

Charles Carson
Jason Klumb
María José Vidal Román

November 2021

Executive Summary

AMERICA'S ETHANOL AND BIODIESEL[1] industries are **growing union jobs** and helping rebuild America's middle class. The percentage of American workers who are union members in the ethanol and biodiesel industries continues to grow. This is good for America. Numerous studies show that union membership in the U.S. results in higher wages and greater equality.[2]

Using U.S. Department of Labor's Bureau of Labor Statistics (BLS) data on union membership,[3] and building on a 2014 report on employment in the ethanol and biodiesel industries prepared by Guerrilla Economics for Fuels America, we estimate that there are **over 30,000 union members** working directly for and in supplier industries to the ethanol and biodiesel sectors. Perhaps most striking is that **union gains are found in farm country and among agricultural workers, both areas where union membership has historically lagged.** The ethanol and biodiesel industries are growing union jobs and helping rebuild America's middle class.

The ethanol and biodiesel industry's positive impact on union density runs counter to national trends. The percentage of American workers who are union members has declined steadily since its peak at around 30 percent in 1954. In 2020, according to the BLS, only 10.8 percent of American wage and salary employees were union members, including only 6.3 percent of private-sector employees. This decline in "union density" has paralleled two other important economic trends that are damaging to American workers: a decline in the percentage of middle-wage, middle-skills jobs in America, and decades-long stagnation in real wages. The perilous result for our country has been a **shrinking middle class.**

> This report finds that America's ethanol and biodiesel industries are creating union jobs for middle-skill American workers both directly and indirectly, and thereby helping to re-build the American middle class.

Our findings are consistent with analyses performed by the Energy Futures Initiative (EFI) in its U.S. Energy and Employment Report for 2019[4] and the U.S. Department

[1] Ethanol is renewable fuel from grains such as corn, sorghum, and barley. Biodiesel is renewable fuel primarily from soybean oil, but also waste grease, *available at* https://afdc.energy.gov/fuels/biodiesel.html

[2] Tom Van Heuvelen and David Brady, "Labor Unions and American Poverty," *ILR Review* (2021): 00197939211014855, citing Kalleberg, Wallace, and Althauser 1981; Freeman and Medoff 1984; Card 1996; Rosenfeld and Kleykamp 2012; Rosenfeld 2014; Rosenfeld, Denice, and Laird 2016; Kristal and Cohen 2017.

[3] U.S. Bureau of Labor Statistics, Union Members 2020 (Jan. 22, 2021) available at https://www.bls.gov/news.release/union2.nr0.html

[4] Energy Futures Initiative and National Association of State Energy Officials, U.S. Energy and Employment Report (Mar 2020), *available at* https://www.usenergyjobs.org/s/USEER-2020-0615.pdf.

of Energy in its U.S. Energy and Employment Report for 2017.[5]

The Energy Futures Initiative found a **union density rate of 7 percent in the ethanol and biodiesel industries in 2019, above the estimated national workforce average of 6 percent.** From the first iteration of the EFI reports, the percentage of union members in the ethanol and biodiesel industries has consistently been higher than the national average.

Higher union density rates in the ethanol and biodiesel industries contrasts favorably with conventional agriculture, where most agricultural workers do not have rights to organize and bargain collectively protected by federal or state law. Also, self-employment is significantly more common in agriculture, which makes union organizing less likely. As a result, conventional agriculture is an industry with a union density rate well below the national average.

The innovation in this report is that we have analyzed union membership rates at the industry level rather than the national level. Outside of the agriculture sector, which creates some complications when analyzing union density, we estimate that **union members in the ethanol and biodiesel industries are concentrated in manufacturing, transportation and utilities, construction, and professional and business services.** Together, these four sectors employ two-thirds of all union members working in the ethanol and biodiesel industries.

This is an important supplemental finding because **manufacturing, transportation, and construction jobs, and some business services jobs, are middle-wage, middle-skill jobs that can help employees and their families sustain middle-class lifestyles.** Unions are important contributors to those good outcomes.

[5] U.S. Department of Energy, U.S. Energy and Employment Report (Jan. 2017), *available at* https://www.energy.gov/downloads/2017-us-energy-and-employment-report.

About the Authors



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Why Union Membership Matters

UNIONS HAVE LONG PLAYED an important role in ensuring that workers secure a fair share of U.S. economic prosperity. At the turn of the 19th Century, union density reached its peak in the U.S. Union density is defined as the percentage of American works who were union members, and at that time nearly 1/3 of American workers were union members. Unemployment was low and real wages were rising for workers at every income level.[6] **America's economy has consistently been fueled in part by union members with middle-class incomes who buy goods and services produced by American workers in a virtuous cycle.** But the virtuous cycle has faded with the decline in union density.

Beginning in the late 1970s and accelerating in the decades to follow, the bargaining power of labor declined, with private-sector union membership now at 6.3 percent. Around the same time, wages and compensation stalled for most workers. **Adjusted for inflation, the average hourly wage of workers is now roughly the same as it was in 1978.**[7]

This study finds that the ethanol and biodiesel industries are growing union jobs and helping rebuild America's middle class.

As a result of slow wage growth among middle-income jobs, the U.S. is currently experiencing record levels of inequality with wealth concentration among top income earners not seen since the 1920s. According to researchers at the Economic Policy Institute (EPI), the decline in union representation directly accounts for a third of the increase in income inequality.[8]

The benefits of unions have long been studied and understood. **There is extensive literature linking union membership to higher wages and greater equality.**[9] Unions also increase the likelihood that workers will receive various forms of non-cash benefits, like health insurance and retirement plans, and reduce wage disparity.[10] Unionized workers are significantly more satisfied with their jobs than their nonunionized counterparts in the

[6] World Inequality Database, available at https://wid.world/country/usa/

[7] Drew Desilver, "For most U.S. workers, real wages have barely budged in decades," Pew Research Center (Aug. 7, 2018), available at http://www.pewresearch.org/fact-tank/2018/08/07/for-most-us-workers-real-wages-have-barely-budged-for-decades/

[8] Colin Gordon, "Union decline and rising inequality in two charts," Economic Policy Institute (June 5, 2012), available at https://www.epi.org/blog/union-decline-rising-inequality-charts/

[9] Tom VanHeuvelen, David Brady, "Labor Unions and American Poverty." ILR Review (2021), citing Kalleberg, Wallace, and Althauser 1981; Freeman and Medoff 1984; Card 1996; Rosenfeld and Kleykamp 2012; Rosenfeld 2014; Rosenfeld, Denice, and Laird 2016; Kristal and Cohen 2017.

[10] See e.g., Unions Help Reduce Disparities and Strengthen our Democracy, Economic Policy Institute (Apr. 23, 2021), available at https://www.epi.org/publication/unions-help-reduce-disparities-and-strengthen-our-democracy/

post-Great Recession period.[11] Unions also protect their members, and others working alongside their members, against dismissals and discipline without good cause, and ensure workers will have a voice in their workplaces, with a result that union members tend to have longer job tenures than non-union workers.[12]

All these benefits that flow from unions in American workplaces help to define what it is to be a member of the middle class in our country. For this reason, supporters of the American union movement, and those committed to restoring the American middle class, should welcome the growth of industries that employ a sizable number of unionized workers, particularly in industries that have declined over the last few decades. **This study's results indicate that the ethanol and biodiesel industries are growing union jobs and helping rebuild America's middle class.**

By the Numbers

We find that of the 313,371 employees directly employed in ethanol production, an estimated **8,776 are union members.** Additionally, supplier industries to ethanol production employ 355,206 employees, **18,686 of which are union members.**

In the biodiesel sector, of the 16,802 employees directly employed in biodiesel production, we estimate that **774 are union members.** Of the estimated 48,798 employees working in supplier industries to biodiesel production, **2,472 are union members.**

Impressively, considering both direct and induced employment, we estimate that there are **over 30,000 employees who are union members in the ethanol and biodiesel industries.**

Because of the sizable percentage of ethanol and biodiesel workers concentrated in agriculture, these high results tend to surprise readers. The union density rate in agriculture is substantially below the national private-sector average (1.7% vs. 6.2%). One reason that union density in agriculture is a fraction of the national rate is that agricultural workers are excluded from the coverage of the National Labor Relations Act (NLRA), the law defining and protecting employees' rights to union organizing and collective bargaining in the U.S. private sector and establishing an administrative agency and system to vindicate those rights. Agricultural workers can organize and bargain collectively pursuant to state law, but only ten states have laws (or judicial decisions) safeguarding those rights and establishing systems like the NLRA model.[13]

[11] Benjamin Artz, David G. Blanchflower, and Alex Bryson, "Unions Increase Job Satisfaction in the United States," No. w28717. National Bureau of Economic Research, 2021.

[12] Katharine G. Abraham and James L. Medoff, "Length of Service and Layoffs in Union and Nonunion Work Groups," ILR Review, Vol. 38, No. 1 (Oct. 1984), pp. 87-97 https://www.jstor.org/stable/2523802

[13] Arizona - (Arizona General Laws §§ 23-1381 to 1395); California - (California Code §§ 1152 through 1155); Idaho - (Idaho Code §§ 22-4101 to 22-4113); Kansas - (Kansas General Statutes §§ 44-818 to 44-831); Louisiana - (Louisiana Code §§ 23:881 to 23:889); Maine - (Maine General Statues §§ 1321 to 1334); Massachusetts - (Mass. General Laws, Chapter 150A § 5A); Nebraska - (Nebraska revised Statutes §§ 48-901 to 48-911); Oregon - (§§ 662.805 to 662.825, enacted in 1963); and Wisconsin - (Wisconsin Code §§ 111.01(2)(6)(c) and 111.115(3)). In New Jersey, a 1947 amendment to the New Jersey Constitution (article 1, paragraph 19) states "persons in private employment shall have the right to organize and bargain collectively." In a 1989 decision, the state supreme court held that this provision applies to agricultural workers, see Comite Organizador de Trabajadores Agricolas v. Molinelli, 552 A.2d 1003 (NJ 1989).

A second potentially important factor affecting the union density rate among agricultural workers is that self-employment is four times more prevalent in agriculture than it is in other industries.[14] Union organizing requires that a workplace have employees, so we would not expect to find union members where we also find self-employment. As such, **many of the union jobs in the ethanol and biodiesel industries are in areas like manufacturing, construction, and transportation that have substantially higher-than-average union density rates.**

For example, the four newest ethanol plants built in California, which are owned by three different companies and collectively constitute more than **$500 million in investment**, were all built pursuant to "project labor agreements" between the companies and the building trades unions that represent construction workers. Project labor agreements, or PLAs, are pre-hire collective bargaining agreements that govern the terms and conditions of employment for all craft workers on a construction project. PLAs protect companies from added construction costs by eliminating costly delays that might result from labor conflicts or shortages of skilled workers. In addition to PLAs, **all outside maintenance and new construction projects for these California ethanol plants are committed to union shops.**

In another example, World Energy plans to convert and modernize a former petroleum refinery in Paramount, California, into a 100 percent renewable energy operation. An estimated **1,000 local union construction jobs** will be created, through a collaboration between World Energy and the State Building and Construction Trades Council, for a facility producing low-carbon intensity biofuel for motor vehicles, trucks, heavy-duty equipment, and aviation.

Unionized workers can also be found operating ethanol plants. For example, as of 2019, Pacific Ethanol's[15] Illinois ethanol plants provide **187 jobs, or one-third of all plant employees, to members of the United Steelworkers of America with payroll and benefits of over $17 million per year**. In another example, Local 103G of the Bakery, Confectionery, Tobacco Workers and Grain Millers International Union represented **600 employees** at a 1,000-acre manufacturing complex in Illinois that processes corn into ethanol and other products. **Unionized workers can be found working for companies that produce ethanol in nearly 20 states, including Alabama, Iowa, Indiana, Kansas, Louisiana, Michigan, Minnesota, Missouri, Nebraska, Ohio, Oklahoma, Tennessee, Texas, and Wisconsin.**

Unionized workers also play a sizable role in the transportation of ethanol and biodiesel. Thirteen unions, some affiliated with larger international unions, represent more than 140,000 employees working for America's freight rail companies. The freight rail industry is one of the country's most heavily unionized industry sub-sectors. Looking at ethanol alone, it cannot be shipped through pipelines because of its alcohol content, so other transportation

[14] See, e.g., "National Trends in Self-Employment and Job Creation," Pew Research Center (Oct. 22, 2015), available at http://www.pewsocialtrends.org/2015/10/22/national-trends-in-self-employment-and-job-creation/

[15] Pacific Ethanol, Inc. recently changed it corporate name to Alto Ingredients, Inc., see https://ir.pacificethanol.com/press-releases/detail/559/pacific-ethanol-completes-name-change-to-alto-ingredients.

modes must be used. **Rail union members help to ship roughly 70% of all ethanol in the United States.** According to the Renewable Fuels Association, since 2010, annual ethanol rail carload originations have held steady at 320,000 to 340,000 per year.[16] This means that approximately **11 billion gallons of ethanol are shipped by rail each year** with the help of workers who are represented by unions.[17]

Data Sources

JOBS ESTIMATES: Union density in the ethanol and biodiesel industries was extrapolated from a report by Guerrilla Economics for Fuels America in 2014. That report estimated that the biofuels industry had created 313,371 jobs that were directly involved in ethanol production. The biofuel industry created another 355,206 jobs among suppliers, according to the Fuels America report. We have updated these estimates by applying industry growth estimates from the annual U.S. Energy and Employment Report (USEER). The "biofuel industry" is defined for statistical analysis to include components of related industries including agriculture, manufacturing, refining, and transportation. In the biodiesel industry, our analysis is based on an economic impact analysis report produced by LMC International for National Biodiesel Board in 2019. Both economic impact reports captured employment in the supply-chain components of ethanol and biodiesel and biodiesel production using an input-output (I-O) model that linked multiple data sources, including both private-sector lists of manufacturing and refining sites and government data on industry employment and economic output. The reports highlighted three types of economic activity: direct, which is economic activity in ethanol and biodiesel production itself; supplier, which is economic activity at firms that provide goods or services used in ethanol and biodiesel production; and induced, which is the economic output across the broader economy from re-spending by employees of industry and supplier firms. Our analysis focused only on direct and supplier economic activity.

UNION DENSITY: Most national union density estimates are based on an annual BLS report. The "union members" report includes data that are broken down by major industry sectors, including both public sector and private sector. State-by-state union density measurements are also available, but these do not include breakouts by industry or public/private sector because the samples would be too small. Because we were able to look at industry sectors by states, we made an important adjustment to our analysis involving agricultural workers that is explained in greater detail in the methodology section below.

OTHER REPORTS: Until 2018, the Department of Energy produced an annual report on energy and jobs in the United States. That report, the U.S. Energy and Employment Report (USEER), is now produced by the Energy Futures Initiative (EFI), a nonprofit think tank based in Washington, D.C. We relied on the 250-

[16] Renewable Fuels Association, Best Practices for Rail Transportation of Fuel Ethanol, found at https://ethanolrfa.org/wp-content/uploads/2017/10/RFA-Best-Practices-for-Rail-Transport-of-Fuel-Ethanol-2017.pdf

[17] U.S. Energy Information Association, Energy-by-rail Methodology, found at https://www.eia.gov/petroleum/transportation/methodology.pdf

page comprehensive 2020 USEER,[18] which reported demographics from 2019, Q4 and showed union membership rates of 7 percent in ethanol, 4 percent in "ethanol and non-woody biomass fuels (including biodiesel)," and 8 percent in "woody biomass fuel for energy and cellulosic biofuels." The combined raw number of union employees in their data is 6,002. They also noted that 44.2 percent of employment identified as ethanol was in agriculture, which traditionally has a significantly lower-than-average union membership rate. Related, most employees in the non-woody biomass fuel, including biodiesel category were in "professional and business services," totaling 47.3 percent, also a category that has lower-than-average union membership rate. Despite this, the union membership in the ethanol and biomass sectors as outlined by the EFI still rated higher than the national average of union membership.

Methodology

ESTIMATES OF TOTAL direct and supplier employment by industry were produced by Guerrilla Economics using the IMPLAN Input-Output model in 2014. Direct employment includes all direct employment in the production or sale of ethanol and biodiesel. It is concentrated in agriculture, manufacturing, and retail sales. Supplier employment includes all indirect employment in supplier industries, and includes professional and business services, financial activities, transportation, and construction, among other industries.

Estimates of union density by industry were produced by the Bureau of Labor Statistics, Current Population Survey, Union Members Supplementary Survey. These were supplemented with Energy Department/EFI Report data, which found a higher overall union density among corn ethanol biofuel production than the national average. However, in consultation with EFI economists, we used only limited data from this survey because the small sample size would result in very large confidence intervals if broken out by industry.

We used the EFI overall estimate of union density to estimate an upper bound to direct employment union density, using the following formulas:

Formula 1

[DOE Total Union Rate] x [EFI Total Emp] = [DOE Total Union Emp]

[BLS Industry Union Rate] x [EFI Industry Emp] = [unadjusted Union Emp] Sum [unadjusted Union Emp] / [EFI Total Emp] = [unadjusted Total Union Rate] [unadjusted Total Union Rate] / [EFI Total Union Rate] = [adjustment factor] [unadjusted Union Emp] x [adjustment factor] =

[adjusted Union Emp]

For the direct employment union members results published in Table 1, the estimates are the midpoint between the lower bound (estimated using solely BLS union density) and the upper bound (estimated using the adjustment factor above). In Table 3, we used LMC's most conservative estimate of

[18] 2020 U.S. Energy and Employment Report (USEER), produced by the Energy Futures Initiative (EFI), available at https://static1.squarespace.com/static/5a98cf80ec4eb7c5cd928c61/t/5ee78423c6fcc20e01b83896/1592230956175/USEER+2020+0615.pdf

domestic biodiesel production as the baseline for biodiesel industry employment and union density. **This approach likely undercounts union membership in this rapidly growing sector.** For the supplier employment union members, the estimates use the BLS union densities, and the following formula:

Formula 2

[BLS Industry Union Rate] x [FA Industry supplier Emp] =
[FA industry supplier Union Membership]

Because agricultural workers are expressly excluded from the coverage of the NLRA, and only ten states provide protections to workers to organize,[19] we modeled agricultural union density separately from non-agricultural union density. Direct agricultural employment in ethanol and biodiesel is concentrated in just a handful of states, and the top seven states, accounting for over 50 percent of direct employment in agriculture, do not provide organizing and collective bargaining protections for agricultural workers. For our estimates, we assumed states without these protections had zero union members, and we used the methodology described above only for the ten states where agricultural workers have protections to organize. **This highly conservative approach likely undercounts union members in this area.** We were not able to make a similar adjustment for the effects of self-employment on union density in agriculture because it is geographically dispersed.

Employment in non-agriculture was not similarly concentrated. We tested our results using statewide union membership rates, and we found no correlation between ethanol and biodiesel employment and statewide union membership. This is because non-agricultural employment was not concentrated in any particular state; employment included states with higher union density like California as well as states with lower union density like Iowa. BLS only publishes industry union membership nationwide, and the only published statewide estimates of union density do not provide industry detail. Using statewide estimates of union density could bias the results based on states with stronger public-sector unions, unrelated to industries involved in ethanol and biodiesel production, so it was appropriate to rely on the national rates to produce our estimates.

The estimates produced here are extrapolations based on existing surveys and model output. Any survey is subject to both response and non-response (also known as sampling) error. BLS data is based on a survey of 60,000 households sampled nationwide and is considered very reliable. Table 2 shows BLS estimates of the 90-percent confidence intervals around union membership rates by industry. It is important to note that confidence intervals are larger when the sample size is smaller, so industries with less employment have less confidence in the estimates of union membership than industries with more employment. Confidence intervals were not available from EFI data, but after consultation with economists and statisticians involved in the production of these estimates, we know that the sample size of this survey would be too small to

[19] See supra note 15 and accompanying text.

produce reliable data on union membership rates by industry. For our purposes in this analysis, we have used EFI data to provide an upper bound on industry union membership rates for direct employment.

Model error is more difficult to estimate. Confidence intervals are not available (and the combination of inputs to the model utilized are proprietary). However, IMPLAN is a well-regarded model, relying on inputs from BLS, Census, and BEA data to estimate industry output and employment based on industry inputs.

Overall, we are combining data from a variety of sources, so it is not possible to directly estimate the error ranges of our estimates. It is possible the establishments that work in ethanol and biodiesel production are systematically more or less likely to have union membership than other establishments in the same industry not involved in ethanol and biodiesel production. The EFI and Energy Department estimates suggest that ethanol and biodiesel establishments are more likely to employ union members than other establishments. However, while the EFI and Energy Department estimates found higher rates of union membership among employees in the ethanol and biodiesel industries compared to private-sector workers overall, their sample was not large enough to confirm that this difference is statistically significant.

Conclusion

OVER 30,000 UNION MEMBERS are working directly for, and in supplier industries to, the ethanol and biodiesel industries. This is particularly compelling because so many of these jobs are in agriculture, which traditionally has lower union membership because most agricultural workers do not have legally protected rights to organize and bargain collectively, and there is a disproportionate amount of self-employment in the sector.

The U.S. biofuel industry supports union jobs in construction and manufacturing, but as importantly relies on sectors with high union densities to store and transport its products. **A key takeaway is that continued support for the ethanol and biodiesel industries will have a positive causal effect on union jobs and is a pathway to an increase in union membership.**

Ethanol and biodiesel industries are also helping to mitigate against a downward trend in U.S. union density rates. **The result of ongoing support for ethanol and biodiesel is likely to be an increase in middle-wage and middle-skill union jobs in traditionally agricultural economies.**

This too is critical to limiting job polarization and economic disparity. The percentage of total employment in middle-skill occupations dropped from 54.9 percent in 1994 to 43.1 percent in 2017.[20] Meanwhile, the percentage of employment in high-skill

[20] Didem Tuzemen, Job Polarization and the Natural Rate of Unemployment in the United States, Kansas City Federal Reserve (Mar. 2018), available at https://www.kansascityfed.org/~/media/files/publicat/reswkpap/pdf/rwp18-03.pdf

occupations rose from 30.4 percent in 1994 to 39.2 percent in 2017, and the percentage in low-skill occupations rose from 14.7 percent in 1994 to 17.7 percent in 2017.[21]

Restoring middle-wage, middle-skills jobs – essential to the maintenance of the American middle class – is possible. Union members occupying those jobs increases the likelihood that wages will be appropriate, benefits will be provided, and workers will have a voice in their economic future. **This report provides data to support the understanding that ethanol and biodiesel industries are contributing to union jobs, with higher benefits, skills, and wages.** In sum, what's good for ethanol and biodiesel is good for unions; and what's good for unions is good for America.

More than 30,000 union members are working directly for, and in supplier industries to, the ethanol and biodiesel industries. In sum, what's good for ethanol and biodiesel is good for unions, and what's good for unions is good for America.

[21] Id.

Notes

Energy and fuel-related agricultural employment was derived using three different calculations for fuelwood, corn ethanol, and biodiesel. The Bureau of Labor Statistics' QCEW cover exclusions were used to develop a factor for agricultural worker exclusions and this factor was applied to employment for the NAICS codes specific to each of the three sub-technologies. Additionally, a technology-specific percentage was derived from ERS estimates for the percentage of total wood, corn, and biodiesel produced that is used for fuel. This percentage was applied together with the exclusion factor to the 2016 Q1 QCEW employment for fuelwood NAICS (113110, 113310, 115310), corn ethanol (11115), and biodiesel (11111) to determine the number of workers that are supporting agricultural fuel production.

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TABLE 1

Estimates of Total Employment and Union Membership, Directly Employed in Ethanol Production and in Supplier Industries to Ethanol Production

	Directly Employed in Ethanol Production	Union Membership	Supplier Employment	Union Membership
Agriculture and related industries	262,830	4,994	100,336	1,906
Mining, quarrying, and oil and gas extraction			5,477	362
Construction			18,611	2,494
Manufacturing	29,090	2,705	32,043	2,980
Wholesale trade	4,134	194	13,620	640
Retail trade	17,317	883	4,895	250
Transportation and utilities			28,088	5,281
Information			4,303	443
Financial activities			57,125	1,542
Professional and business services			73,607	2,208
Education and health services			1,376	133
Leisure and hospitality			12,396	347
Other services			3,329	100
TOTAL	313,371	8,776	355,206	18,686

Source: Total Direct and Supplier employment produced by Guerilla Economics for Fuels America. Union Membership from authors' calculations.

TABLE 2

Estimates of Union Membership by Industry Sector

INDUSTRY	Union Membership 2020
Private sector	6.3
Agriculture and related industries	1.7
Mining, quarrying, and oil and gas extraction	5.6
Construction	12.7
Manufacturing	8.5
Wholesale trade	4.3
Retail trade	4.6
Transportation and utilities	17.6
Information	9.3
Financial activities	1.9
Professional and business services	2.2
Education and health services	8.4
Leisure and hospitality	2.2
Other services	2.5

Source: U.S. Bureau of Labor Statistics, Current Population Survey, https://www.bls.gov/news.release/pdf/union2.pdf

TABLE 3

Estimates of Total Employment and Union Membership, Directly Employed in Biodiesel Production and in Supplier Industries to Biodiesel Production

	Directly Employed in Biodiesel Production	Union Membership	Supplier Employment	Union Membership
Seed Production*	7,584	129	17,116	291
Animal Processing and grease collection	2,745	47	9,055	154
Local seed delivery	415	7	585	10
Elevation	605	10	1,795	31
Oilseed crush	872	74	4,328	368
Feedstock delivery by barge	227	39	673	114
Feedstock delivery by rail	76	13	224	38
Biodiesel processing	3,201	272	12,799	1,088
Rail deliveries of domestic Biodiesel used domestically	328	56	972	165
Rail deliveries of glycerin	76	13	224	38
Rail deliveries of imported Biodiesel	0	0	0	0
Rail deliveries of exported Biodiesel	50	9	150	25
Trucking domestic to sale	457	78	643	109
Trucking imports to sale	125	21	175	30
Import port activities	42	7	58	10
Export port activities	0	0	0	0
TOTAL	**16,802**	**774**	**48,798**	**2,472**

Note: We used LMC's most conservative estimate of domestic biodiesel production as the baseline for biodiesel industry employment and union density, which **likely undercounts union membership** in this growing sector.

Senator CARPER. Next is Senator Inhofe. Senator Inhofe will be followed by Senator Whitehouse.

Senator Inhofe.

Senator INHOFE. Thank you, Mr. Chairman. Before you start my clock, I am going to experiment with something that I haven't tried before. I have two questions, but the first question has four parts, so rather than put Ms. Johnson in a position of having to write down fast, I am going to ask my staff to hand her the written copy of those four questions, which I will read now.

First of all, Ms. Johnson, will——

Senator CARPER. The Senator's time has expired.

[Laughter.]

Senator INHOFE. I didn't do that to you.

Senator CARPER. All right, go ahead.

Senator INHOFE. Will denial of the small refinery exemptions, of which we have two in Oklahoma, ultimately drive gas prices up, and does the data support the assertion that small refinery exemptions lower blending and biofuels? Please describe your understanding of the EPA's stakeholder engagement with refiners regarding the proposed rule. And is there data to support the claim that EPA's denial of hardship relief for small refineries would contribute to closure of American refineries and lost jobs? Anything that has already been answered, you can go ahead and run over that fast. All right?

Ms. KOCH. Thank you, Senator Inhofe, and thank you for the list of questions.

With respect to your first question of whether denial of small refinery exemptions will drive compliance costs higher and gas prices higher, it is a certainty. If EPA publishes its proposed denial, the parties holding the RINs that small refineries need for compliance will be in a position to demand exorbitant prices because small refiners will be captive buyers on the eve of the compliance deadlines, multiple compliance deadlines on top of one another, because EPA has been so delayed in its rulemaking.

This is assuming that RINs are available at all, so my small refineries do not have the RINs that they need for compliance. They are physically unavailable. No more 2019s are available for compliance; no more 2020s are available for compliance because, as EPA described, parties' uncertainty about what the ultimate volumes will be are holding onto their excess RINs.

It is a recipe for crushing small refineries. It is a recipe for escalating RIN prices. They will get much worse if EPA moves forward with its proposal. Gas prices will increase with RIN prices for parties that can partially or fully pass through their costs; for example, large, integrated oil companies and large, exempt retailer chain, and small refineries will be forced to violate the law without hardship relief, shut down, curtail, or go bankrupt. Those are the Department of Energy's predictions.

With respect to your second question, Senator, does the data support the assertion that small refinery exemptions lower blending of biofuels, I want to answer that in two parts. First of all, EPA's current proposal relates to compliance years 2019, 2020, and 2021. It is impossible to blend any more fuel in those years. Those years have already closed, so no, no biofuel blend rate will go down.

Essentially, the other proof is that, there is a lot of discussion about the 2016 to 2018 timeframe when the prior Administration granted more hardship relief than it had historically. During the period of time when small refinery hardship increased, so did the blend rate, and the simple reason is small refineries cannot meaningfully impact the blend rate. The blend rate, the blending is done downstream. The only question is whether or not small refineries are going to make massive wealth transfer to the large, integrated oil companies and large, exempt blenders that hold the RINs needed for compliance.

Your third question was to describe stakeholder engagement with refiners regarding the proposed rule. I can say this: Small refiners were blindsided by EPA's proposal to retroactively deny all 2019 to 2021 petitions years after their statutory deadline to issue their decisions had passed. EPA checked a box. They met with us on August 25th of 2021. They shared no substance about their plans to issue retroactive mass adjudications and denials for small refineries.

The proposal matches entirely, instead, the asks of the biofuel industry, which seems to have had meaningful engagement with EPA. EPA also seems to have engaged with the USDA, and by the way, you, Congress, decided that the appropriate consultation was with the Department of Energy, not Ag, and the Department of Energy is, as I have said, has determined that EPA's plan to deny hardship relief will result in the shutdown and closure of refineries.

Your last question, Senator, was whether there is data to support the claim that EPA's denial would contribute to the closure of American refineries and lost jobs. I won't repeat what I said previously, but essentially, a number of small refineries do not have the RINs they need for compliance. If they are denied relief, they will be captive buyers in a market with escalating RIN prices.

EPA has acknowledged that there was a shortcoming in the production of RINs for the 2019 compliance year, and that the RINs that are available in the market are not in the hands of small refineries. Small refineries will necessarily violate the Clean Air Act because they will not have the ability to get the RINs that they need for compliance, which will then force them to decide between spending money on RINs if they have it, shutting down, and/or going into bankruptcy.

Senator, I hope I have answered each of your questions.

Senator INHOFE. Excellent.

Senator CARPER. And you have done it in just the right amount of time. The gentleman's time has expired.

Go ahead, just briefly. Very briefly.

Senator INHOFE. I do have one last thing for Mr. Pugliaresi, and that is, is there anything, I know you talked about this, and you answered a question addressing this also, but is there anything in terms of the risks associated with an entirely electric fleet that you didn't adequately cover?

Senator CARPER. Just very briefly if you would, please, very brief in your response.

Mr. PUGLIARESI. Yes. The biggest problem is, we are energy independent now. In order to move to an electric fleet, we have to move

to a series of critical materials and minerals, on which we will be highly dependent. Some of them sourced from countries that are not necessarily friendly to the United States.

If I may just correct—one question that I thought was very interesting, it is very important to understand that Oregon has the fifth highest gasoline prices in the country, so it may be lower than some other adjoining States, but gasoline prices are quite high in Oregon.

Senator CARPER. All right, thank you.

Senator Whitehouse, you are up. Thanks very much.

Senator WHITEHOUSE. Thank you, Chairman, and thanks everyone for being here.

I have long supported the biofuels and ethanol standard, but it has kind of been an act of faith that someday the market would come around and that corn ethanol, in particular, was kind of a pathway effort that would let cellulosic ethanol and other forms come forward.

I am interested, Ms. Wind, in your testimony about the carbon intensity of the ethanol and biodiesel that Oregon uses, that it has decreased. I am wondering how confident you are in the measure of carbon intensity of your corn ethanol fuel stock.

Ms. WIND. Yes, thank you for that question, Senator. We do use the Argonne grade model to calculate carbon intensities in the State of Oregon, which is the accepted national model to do so.

With respect to the ethanols that we are receiving in Oregon, the import of that fuel, it is producer specific, and so we can keep very close track of the different ethanols that we are getting, even the corn ethanols. What we are seeing is incremental decreases in the carbon intensity.

So, for ethanol over the past 6 years, it has continued to incrementally go down, probably about 10 percent. The carbon intensity of the biodiesels have had more of a significant decrease, but it is steady, and it shows that there is value in a low carbon fuel standard to continue to draw down those carbon intensities. These facilities are getting more efficient and better at their energy inputs, and that is reflected in the lower carbon intensity scores.

Senator WHITEHOUSE. You mentioned cellulosic ethanol, I believe. What is the market share within the ethanol market of cellulosic ethanol, or in your portfolio, if you know that better than the national market?

Ms. WIND. Yes, thank you for that, Senator. As far as cellulosic ethanol, we don't have any cellulosic ethanol coming into the State of Oregon. What the ethanol that is coming into Oregon, it is not cellulosic, but it is decreasing in carbon intensity.

Senator WHITEHOUSE. Is it? How much of it is corn?

Ms. WIND. It is 100 percent corn.

Senator WHITEHOUSE. OK, there we go. One of the things that I think we need to do in order to find a pathway to climate safety is to put a price on carbon. That seems to be a fairly commonly held view among economists and banks and so forth and among people who are looking hard at the climate problem for emissions reduction solutions.

At present, the absence of one is a really massive subsidy for the fossil fuel industry. The International Monetary Fund calculates it

north of $600 billion per year, just in the United States. Six hundred billion dollars per year is an enormous number, and it provides a very strong motive for a massive political elections lobbying operation by the protected and subsidized fuel to defend and protect its subsidy politically. We are in a kind of a difficult position here in Congress.

I am wondering, back to you again, Ms. Wind, if there were a price on carbon, how would that affect the ethanol portion of your fuel market?

Ms. WIND. Thank you for that question. In effect, the way that the low carbon fuel standard works is that the monetization, the value of the fuel, is in the credit prices that are being traded in the program. This is a market that we do not control. It is a market that contributes to the credit prices, the credit center traded within the program.

Currently speaking, the credits in the State of Oregon are trading at about $125 per ton. It has been higher, and it has been lower. We publish that on a monthly basis to show transparency to the market. There is certainty in what that credit price is, that is associated with the carbon. That is how we do it in the low carbon fuel standard.

Senator WHITEHOUSE. My time is up.

Chairman, thank you very much.

Senator CAPITO. Thank you.

Senator Cramer.

Senator CRAMER. Thank you, Senator Capito. Thanks to all of you for being here.

This is a topic that has perplexed me since the day I got to Congress. It is not the topic that perplexes me as much as the debate. It never changes. A lot has changed since 2005 and 2007, when the RFS was created, during a time of scarcity of natural resources. Of course, we now have an abundance of natural resources.

In the meantime, we have some other policy decisions. We have an Administration right now pushing for up to $12,500 per electric vehicle subsidy to change the demand for electric vehicles. I am going to just state some facts, and then I am going to ask for some feedback.

We have this debate over this constantly moving target, right? Several of us have had this discussion. What I would say would be, as a result of lazy legislating, which I am convinced is a historical phenomenon in this country, Administrations have been given an awful lot of leeway to determine things like RVOs, even when they are stated in the law.

Obviously, the hardship, the small refinery hardship waivers are another tool, and then we get upset because, you know, for 4 years, it is one way, then for 4 years, it is another way, and then for 4 years, it is another way. I know a couple of you and I have had this discussion.

But it seems to me that at the end of this hearing—for the last decade, several people I have discussed this with have liked to deny that at the end of 2022, there is a new rule in place, that the RVOs are no longer in law. They are in law, but they are not required, that the authority to set the RVOs—in other words, the

EPA and the Administration has even more unilateral authority after this year.

I would like to just have a little discussion from the panel. What is your understanding, we will start with you, Ms. Koch, what is your understanding of the act when the RVOs switch over, or the EPA gets carte blanche, in my view, authority in 2023 to set the RVOs? Where are going to go if nothing happens and they have that authority?

Ms. KOCH. Thank you, Senator. I think that is an excellent question, and something that keeps me awake at night.

I see this freight train heading toward the highest possible RVOs to try to break through the blend wall and to promote E15. The problem is that EPA had discretion in how to set up the program, and it set up the program in such a way that it distorted competition.

Growth Energy has stood shoulder to shoulder with the American Petroleum Institute, which represents the large, integrated refineries, preventing closing the blender loopholes. So essentially, Growth's theory is that just keep pushing, just keep pushing, just keep pushing, at some point, E15 will happen.

E15 won't happen before every small refinery is shut down, because right now, we are counting on volunteer blending, what we call the blender loophole. Small refineries do not have the ability to blend. Large, integrated refineries have the ability to blend more than they produce.

Until this market distortion is fixed, it is a recipe for destroying those refineries that cannot blend. So if we want to keep pushing E15, if we have in fact determined that E15 results in reductions in greenhouse gas emissions, which is something that I don't think we at all agree with, we need to fix the structure of the program.

I was interested in the discussion of cost caps. Very many times, limitations on the ability to speculate in the RIN market, limitations on the cost of a RIN, obligating blenders, all of these proposals to fix the things that are preventing renewable fuel blending have not occurred. If we just go straight ahead, we are going to just collateral damage our industry.

Senator CRAMER. Ms. Skor, first of all, I want you to be able to respond to that, but couldn't a future Administration, instead of pushing E15, just eliminate, could they go to zero? Would that be possible, 1 gallon or something like that, in the law?

Ms. SKOR. Senator, thank you for the question. Yes, after 2023, there are no congressionally set blending requirements, so EPA does have greater flexibility in terms of setting the blending obligations. A few important things they still have, some criteria that they need to consider, job creation, energy independence, environmental impact.

I think one of the things that we have all suffered from, in every sector, is the lack of certainty and stability. If there is an obligation, it needs to mean something. If there is a deadline, it needs to mean something.

One of the things we look forward to in the set is EPA's opportunity to set blending requirements for multiple years in advance, similar to what Ms. Wind was talking about in Oregon. I think that would help address some of the volatility concerns.

Senator CRAMER. Thank you. I wish we had more time.

Maybe in another round, Mr. Chairman.

The biggest point that I want to make is that 2022 is here now. For 10 years, people looked at me like, don't worry, that is in the future. Well, it is not in the future anymore. We have to come up with something. I would rather come up with it with everyone in the room, if you know what I am saying.

Senator CARPER. As long as it includes us.

Senator CRAMER. As long as you are in the room with me, I am good, yes.

Senator CARPER. Thank you, sir. All right. Thanks, Senator Cramer.

Senator Duckworth, I think you are out there on Webex. If you are, please proceed.

Senator Duckworth. No?

Senator Lummis is here in person, live and in person. We will come back to Senator Duckworth when she can rejoin us.

Senator Lummis, you are recognized. Then, I have Senator Stabenow after you by Webex. Go ahead, please. Thanks.

Senator LUMMIS. Thank you, Mr. Chairman.

I would like to begin by asking consent to enter three documents into the hearing record. One is an academic study published in the Proceedings of the National Academy of Science called Environmental Outcomes of the U.S. Renewable Fuel Standard. The second is a study by the University of Georgia called Analyzing the Downstream Impacts of U.S. Biofuel Policies. The third is an article entitled U.S. Bread and Donut Makers Urge Biden to Roll Back Biofuel Requirements.

Senator CARPER. Is there objection?

Hearing none, so ordered.

[The referenced information follows. One of the documents was unavailable for printing but is available in Committee files.]

Environmental outcomes of the US Renewable Fuel Standard

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The Renewable Fuel Standard (RFS) specifies the use of biofuels in the United States and thereby guides nearly half of all global biofuel production, yet outcomes of this keystone climate and environmental regulation remain unclear. Here we combine econometric analyses, land use observations, and biophysical models to estimate the realized effects of the RFS in aggregate and down to the scale of individual agricultural fields across the United States. We find that the RFS increased corn prices by 30% and the prices of other crops by 20%, which, in turn, expanded US corn cultivation by 2.8 Mha (8.7%) and total cropland by 2.1 Mha (2.4%) in the years following policy enactment (2008 to 2016). These changes increased annual nationwide fertilizer use by 3 to 8%, increased water quality degradants by 3 to 5%, and caused enough domestic land use change emissions such that the carbon intensity of corn ethanol produced under the RFS is no less than gasoline and likely at least 24% higher. These tradeoffs must be weighed alongside the benefits of biofuels as decision-makers consider the future of renewable energy policies and the potential for fuels like corn ethanol to meet climate mitigation goals.

biofuels | land use change | greenhouse gas emissions | water quality | environmental policy

Bioenergy is an essential component of most proposed pathways to reduce anthropogenic greenhouse gas (GHG) emissions and limit global warming to 1.5 or 2 °C by middle to late century (1–6). Liquid biofuels may contribute to bioenergy's share of climate mitigation by displacing petroleum-based fuels with those generated from modern-day plants (7, 8). The GHG benefits of such substitution, however, are dependent on several factors including whether biofuel production invokes additional plant growth (9–12), the extent to which combusted plants (typically crops) are replaced in the food system (13–15), and the degree to which biofuel production directly and indirectly alters patterns of land use and management (2, 16–20). Because land use changes (LUCs) and other consequences induced by biofuels have the potential to cause significant novel GHG emissions and modify other ecosystem services and disservices (21–26), accurately estimating and accounting these outcomes is critical for the formation of effective climate and environmental policy (27–29).

The United States is the world leader in biofuel production by volume and generated 47% of global output over the last decade under the purview of its Renewable Fuel Standard (RFS) (30). First enacted in 2005 and greatly expanded in 2007, the RFS requires that biofuels be blended into the transportation fuel supply at annually increasing increments. Volume targets exist for several advanced biofuel types including biomass-based diesel and those made from cellulosic feedstocks. However, the vast majority (~87%) of the mandate to date has been fulfilled by conventional renewable fuels, specifically corn grain ethanol (30, 31), such that the potential benefits of its more advanced fuel requirements have not yet materialized (32–34).

To comply with the policy's GHG reduction goals, the RFS requires conventional renewable fuels to generate life cycle GHG savings of at least 20% relative to gasoline. Upon enactment, the policy's regulatory analysis projected that life cycle emissions of corn ethanol production would just clear the 20% threshold by 2022, even when emissions from LUC were included (35). At the time, most LUC emissions were projected to occur internationally. Since the initial RFS policy-making, however, observations of widespread land conversion and resultant GHG emissions within the United States have also emerged (36–39).

Heightened demand for crops for use as biofuel feedstocks and the associated changes to landscapes may also engender broader environmental disservices upon ground and surface waters, soil resources, and other ecosystem components (40–44). The magnitudes of such effects are highly uncertain, however, as they ultimately depend upon unpredictable behaviors throughout the supply chain—from field to refinery—making it difficult to forecast impacts. As such, public policy-making and support for biofuels has needed to rely on widely varying projections of

Significance

Biofuels are included in many proposed strategies to reduce anthropogenic greenhouse gas emissions and limit the magnitude of global warming. The US Renewable Fuel Standard is the world's largest existing biofuel program, yet despite its prominence, there has been limited empirical assessment of the program's environmental outcomes. Even without considering likely international land use effects, we find that the production of corn-based ethanol in the United States has failed to meet the policy's own greenhouse gas emissions targets and negatively affected water quality, the area of land used for conservation, and other ecosystem processes. Our findings suggest that profound advances in technology and policy are still needed to achieve the intended environmental benefits of biofuel production and use.

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anticipated effects—a quandary that could potentially misguide strategies for climate change mitigation and environmental protection (27, 28, 45).

The RFS legislation contains several environmental safeguards to try to prevent perverse outcomes including periodic scientific review of the conservation impacts of the program and opportunities to adjust annual fuel volumes if the program creates severe environmental harm (31). Although the most recent program review identified that biofuels may in fact be contributing to land conversion and subsequent declines in water quality, these impacts have not been causally attributed to biofuels or the RFS (32). Likewise, volume requirements for specific fuel types have not been revised based on environmental performance (31). Given the United States' leading role in biofuel production, understanding the outcomes of the RFS has direct ramifications not only for national environmental quality and global climate change but also for policy-making around the world as governments seek to modify or develop their own biofuel policies to meet climate and clean energy goals.

Here we assess the effects of the RFS on US land and water resources during the first 8 y of the policy's implementation (2008 to 2016) by integrating econometric analyses with observed changes in agricultural land use and models of biophysical impacts. We analyze how demand from the RFS affected corn, soybean, and wheat prices and how these price shocks influenced the areas planted to specific crops and cropland overall. We then assess how these changes affected key environmental indicators including nitrate leaching, phosphorus runoff, soil erosion, and GHG emissions. For all estimates, we compare outcomes under the 2007 RFS to a business-as-usual (BAU) counterfactual scenario in which ethanol production satisfies only the volume required by the initial 2005 version of the policy, equivalent to the amount needed for reformulated gasoline under the 1990 Clean Air Act. We apply our models only domestically, such that any environmental effects that occur outside the United States would be additional.

Our analyses show a modest change in the use of US agricultural land for crop production due to the RFS, which led to sizable increases in associated environmental impacts including nitrate leaching, phosphorus runoff, and soil erosion. While improvements in production efficiency have likely reduced the carbon intensity of corn ethanol since inception of the RFS, the previously underestimated emissions from US land conversion attributable to the policy are enough to fully negate or even reverse any GHG advantages of the fuel relative to gasoline. Our findings thereby underscore the importance of including such LUCs and environmental effects when projecting and evaluating the performance of renewable fuels and associated policies.

Results and Discussion

We found that the RFS stimulated 20.8 billion L (5.5 Bgal) of additional annual ethanol production, which requires nearly 1.3 billion bushels of corn after accounting for coproducts that can be fed to animals (46). This heightened demand led to persistent increases in corn prices of ~31% (95% confidence interval [CI]: 5%, 70%) compared to BAU (Fig. 1). The increased demand for corn also spilled over onto other crops, increasing soybean prices by 19% [−8%, 72%] and wheat by 20% [2%, 60%] (*SI Appendix*, Table S1). These outcomes approximate the contribution of the RFS policy specifically, although other factors including changes in fuel blending economics that favored 10% ethanol as an octane source in gasoline (E10) may also have contributed (*SI Appendix*, *Supplementary Results for Price Impacts*).

The increase in corn prices relative to other crops increased the area planted to corn on existing cropland by an average of 2.8 Mha* per year [95% CI: 2.4, 3.1], which is an 8.7% increase attributable to the RFS. This additional area resulted from producers planting corn more frequently, including a 2.1 Mha [1.8, 2.3] increase in continuous corn production (i.e., sequential year cropping) and a 1.4 Mha [0.8, 1.9] increase in the area planted in rotation with other crops (*SI Appendix*, *Supplementary Results for Crop Rotations* and Fig. S1). Collectively, corn area increased most markedly in North and South Dakota, western Minnesota, and the Mississippi Alluvial Plain—regions where the amount of corn increased 50 to 100% due to the RFS (Fig. 2*A* and *SI Appendix*, Fig. S1).

Heightened commodity prices from the RFS also increased active cropland extent. We estimate that the RFS caused conversion of an additional 1.8 Mha [95% CI: 1.5, 2.1] of natural and seminatural areas to cropland between 2008 and 2016, or 26% more than would have otherwise likely occurred (*SI Appendix*, *Supplementary Results for Cropland Area* and Table S2). Higher prices also reduced cropland abandonment; less cropland was returned to grass or natural cover, either as pasture or through enrollment into the Conservation Reserve Program (CRP), a federal set-aside that pays farmers to reestablish perennial vegetation. We estimate that the RFS decreased abandonment by 0.4 Mha [0.1, 0.6], or 6% less abandonment than expected with BAU. Together these extensive changes produced a net increase in cropland area of 2.1 Mha [1.8, 2.5] relative to BAU, with the greatest increases occurring in the western portions of existing agricultural regions (Fig. 2*B* and *SI Appendix*, Fig. S2).

The combined changes in the intensity of corn production and extent of cropland caused 7.5% more reactive nitrogen (N) from synthetic fertilizer to be applied annually to the landscape (Table 1). This contributed to a 5.3% increase in nitrate (NO_3^-) leached annually from agricultural land due to the RFS. Such nitrate losses occurred through vertical seepage below the root zone, where nutrients are no longer accessible to crops, and have been implicated in widespread groundwater contamination throughout the United States with major public health consequences (47, 48). Leaching was highest in regions with high N inputs and coarse soil texture (Fig. 2*F* and *SI Appendix*, Figs. S3 and S4), with nearly two-thirds of the overall nitrate increase stemming from changes to crop rotations.

The RFS also increased total edge-of-field phosphorus (P) runoff by 3.2% (Fig. 2*I* and *SI Appendix*, Figs. S5 and S6). This change was driven by a 3.5% increase in total P applications (Fig. 2*G*) and a 4.7% increase in soil erosion (Fig. 2*H*), which transports dissolved and sediment-bound P to downstream surface waters, where it often causes eutrophication and harmful algal blooms (41, 47, 49). Erosion losses from crop fields can also degrade soil quality over time (50, 51), contribute to enhanced GHG emissions in waterways (52), and impair water quality and aquatic habitat (53, 54) including that of threatened and endangered species (55, 56).

Collectively, increased nitrate leaching, phosphorus runoff, and soil erosion from the RFS fall within the range of outcomes projected at its outset (41, 57, 58) and substantiate longstanding concerns about the policy's environmental disservices. However, we find disproportionate effects and distinct spatial patterns from different pathways of land use response. Shifting crop rotations toward more corn increased N fertilizer applications and nitrate leaching by nearly twice that of cropland area changes, due largely to the high N requirements of corn relative to other crops. In contrast, erosion-driven P and soil losses

*See *SI Appendix* results: Our model of key growing regions accounts for 91.6% of corn acres in the United States. If one assumes a similar response in the remaining unmodeled area, then the nationwide change is 3.0 Mha or 8.9% more than the amount expected without the RFS.

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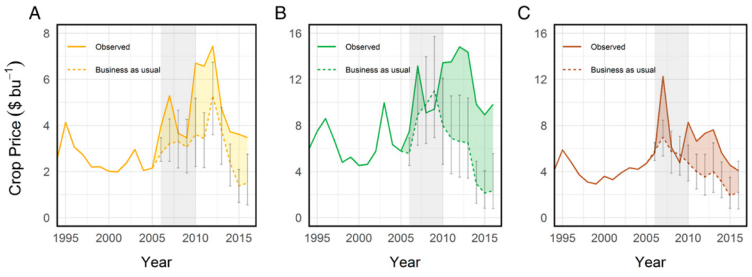


Fig. 1. Observed and BAU estimates for crop prices. (*A*) Corn. (*B*) Soybeans. (*C*) Wheat. Vertical bars represent the 95% CIs for each BAU spot price. Each year denotes a crop year; e.g., 2006 is September 2006 to August 2007 for corn and soybeans and June 2006 to May 2007 for wheat. Averages for 2006 to 2010 (highlighted in gray) were used to derive the estimates in the text, although long-run persistent impacts were consistent with these results (46).

from cropland area expansion were roughly two and three times greater, respectively, than those from increased corn planting—a difference that reflects substantially higher erodibility and P inputs of croplands relative to uncultivated land, particularly in the marginal, steeper-sloped areas that were converted (e.g., *SI Appendix*, Fig. S6*J*) (37, 59, 60).

Beyond its water quality effects, the RFS substantially increased on-site GHG emissions from cropping systems. We found that greater use of N fertilizer increased nitrous oxide (N_2O) emissions by 8.3% or 4.1 Tg CO_2e y^{-1} relative to BAU (Fig. 2*E*). Most of this (68%) can be attributed to intensified corn production on preexisting fields, where emissions increased by 5.7%, with the remainder emitted from the expanded croplands.

In addition to these annual fertilizer application emissions, degradation of ecosystem carbon (*C*) stocks from cropland expansion led to a substantial pulse of committed GHG emissions. These arise from clearing land for crop production and are typically realized over a period of roughly 30 y unless proactively mitigated (35, 61). We estimate emissions associated with RFS-induced conversion to cropland to be 320.4 Tg CO_2e [95% CI: 250.5, 384.3], or ∼181 Mg CO_2e ha^{-1}.

Further, reduced rates of cropland retirement—through CRP enrollment or transition to pasture—has reduced C sequestration that would have otherwise resulted from perennial grassland reestablishment and recovery. We estimate this forgone sequestration at 77.3 Tg CO_2e [95% CI: 30.8, 126.8], assuming that abandoned land would accumulate carbon for 15 y—the standard duration of a single CRP contract—after which its carbon fate becomes contingent upon subsequent management. Combined, the RFS-driven changes in cropland area between 2008 and 2016 caused a total net C flux of 397.7 Tg CO_2e [313.3, 481.7] to the atmosphere (Fig. 2*C*).

Domestic LUC emissions spurred by the RFS undermine the GHG benefits of using ethanol as transportation fuel. Assuming 30-y amortization, ecosystem C emissions from the RFS-induced LUC equate to 637 g CO_2e L^{-1} of increased annual ethanol production or an emissions intensity of 29.7 g CO_2e MJ^{-1} (*SI Appendix*, Table S3). Including on-site annual nitrous oxide emissions from increased fertilizer application further increases these emissions to 831 g CO_2e L^{-1} or 38.7 g CO_2e MJ^{-1}. These findings stand in stark contrast to the −3.8 g CO_2e MJ^{-1} of domestic LUC emissions estimated by the RFS regulatory impact analysis (RIA) and surpass the 30.3 g CO_2e MJ^{-1} estimated by the RIA for international LUC (35).

Substituting our empirically derived domestic emissions for those modeled in the RFS RIA would raise ethanol's projected life cycle GHG emissions for 2022 to 115.7 g CO_2e MJ^{-1}—a value 24% above baseline gasoline (93.1 g CO_2e MJ^{-1}). The RIA estimate, however, includes improvements in feedstock and ethanol production efficiency that were projected to occur by 2022, such that the GHG intensity of ethanol produced at earlier time periods and over the life of the RFS to date is likely much higher [*SI Appendix*, *Supplementary Results for Greenhouse Gas (GHG) Emissions from Land Use Change (LUC)*].

Incorporating the domestic LUC emissions from our analysis into other fuel program estimates similarly annuls or reverses the GHG advantages they calculate for ethanol relative to gasoline (Fig. 3 and Table 2). However, life cycle GHG emissions accounting requires consistent treatments and system boundaries across analyses (27, 64–66). As such, a full reanalysis, rather than the partial revisions we illustrate here, should be conducted to accurately assess ethanol's carbon intensity relative to other fuels, particularly given the magnitude of domestic LUC emissions identified. For instance, we likely underestimate total domestic LUC impacts since we consider only the on-site ecosystem C and nitrous oxide emissions but do not account for additional emissions from increased fertilizer production (67) or from water quality–related increases in N, P, and sedimentation, which have been shown to augment GHG emissions in downstream waterways (52, 68, 69).

Furthermore, we assess only the domestic (US) impacts of the RFS and expanded corn ethanol production. However, evidence of such effects reaffirms the likely presence of international LUC in response to the RFS (16, 19, 28, 70). As such, our results should be considered the lower bound for total GHG and other environmental impacts. We also limit our focus to select environmental outcomes but note that interconnected outcomes related to food systems (13, 14), human health (71), and the welfare of different groups of society (72) likely exist. For example, several assessments of the GHG implications of the RFS model a concomitant reduction in global food and feed consumption (13, 19).

Although we describe the incremental effects of the expanded RFS program, our findings are representative of the observed outcomes from corn ethanol development broadly, regardless of the cause. Our estimates imply that for every billion gallons per year (BGY) expansion of ethanol demand, we would expect a 5.6% increase in corn prices; 1.6 and 0.4% increases in the areas

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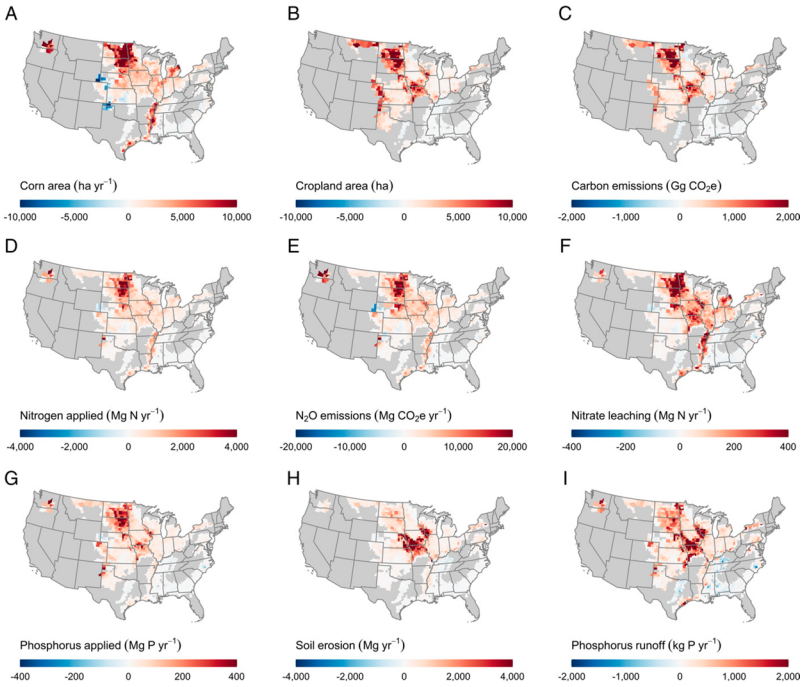


Fig. 2. Changes due to the RFS. (*A*) Corn planted area. (*B*) Cropland area. (*C*) Carbon emissions. (*D*) Nitrogen applications. (*E*) Nitrous oxide emissions. (*F*) Nitrate leaching. (*G*) Phosphorus applications. (*H*) Soil erosion. (*I*) Phosphorus runoff. Positive numbers indicate an increase due to the RFS. Field-level results were aggregated to the county level for enumeration and visualization.

of US corn and cropland, respectively; and attendant increases in GHG emissions, nutrient pollution, and soil erosion (Table 1; %Δ per BGY). Our findings are also specific to corn ethanol and do not reflect advanced renewable fuels, which have lower production volumes and are required to meet stricter GHG reduction thresholds. To date, however, most RFS biofuel production has come from conventional corn ethanol, thereby missing much of the policy's promised emissions savings and potential environmental benefits expected from more advanced feedstocks (2, 35, 73).

Despite the strong environmental tradeoffs under the RFS thus far, biofuels and bioenergy may play a key role in stabilizing atmospheric CO_2 concentrations and holding global warming below 1.5 or 2 °C, particularly with continued advancements like carbon capture and storage (2, 4, 74–76) and increased productivity from perennial feedstocks grown on marginal lands (77–80). However, our findings confirm that contemporary corn ethanol production is unlikely to contribute to climate change mitigation. Given the current US dependence on this fuel, there remains an urgent need to continue the research, development, and shift toward more-advanced renewable fuels, improved transportation efficiency, and electrification (74, 81–83).

The United States is currently at a bioenergy crossroads. The RFS specifies biofuel volumes through 2022; absent legislative action, the Environmental Protection Agency (EPA) will determine volumes for subsequent years. If conventional biofuel volumes were to increase, it is likely that further increases in crop prices, LUC, and environmental impacts would ensue. Alternatively, a decrease in mandated volumes may have less effect, given the capital investment, established markets, and economic value of producing ethanol at existing levels. More broadly, any increases in demand for corn ethanol from nonfederal jurisdictions, including US states or trade partners like Canada and China, are likely to exacerbate the domestic land use and environmental outcomes identified here.

As policy-makers worldwide deliberate the future of biofuels, it is essential that they consider the full scope of the associated tradeoffs, weighing the GHG and other environmental externalities alongside each fuel's benefits. By quantifying and attributing the outcomes of policy thus far, our findings provide

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Table 1. Net changes due to the RFS

	Land use		GHG emissions		Environmental indicators				
	Corn area (Mha y^{-1})	Cropland area (Mha)	Nitrous oxide ($TgCO_2e$ y^{-1})	Ecosystem carbon ($TgCO_2e$)	N applied (Gg-N y^{-1})	P applied (Gg-P y^{-1})	Nitrate leaching (Gg-N y^{-1})	P runoff (Mg-P y^{-1})	Soil erosion (Gg y^{-1})
Crop rotation Δ	2.8	—	2.8	—	480.0	21.3	87.1	203.2	222.9
95% CI lower limit	2.4	—	2.3	—	377.3	1.2	56.9	−27.7	11.6
95% CI upper limit	3.1	—	3.2	—	577.0	41.2	117.7	449.3	423.6
Cropland extent Δ	—	2.1	1.3	397.7	237.3	48.2	47.9	439.0	633.9
95% CI lower limit	—	1.8	1.0	313.3	190.5	38.4	33.5	273.6	485.9
95% CI upper limit	—	2.5	1.5	481.7	281.8	57.7	62.1	592.6	780.6
Combined total Δ	2.8	2.1	4.1	397.7	717.2	69.5	135.0	642.2	856.7
95% CI lower limit	2.4	1.8	3.5	313.3	626.7	58.9	111.6	476.9	697.6
95% CI upper limit	3.1	2.5	4.5	481.7	806.5	79.5	157.8	798.0	1,011.4
BAU baseline	31.7	88.4	48.6	—	9,545.5	1,986.4	2,535.5	19,939.3	18,038.7
%Δ from BAU	8.7%	2.4%	8.3%	—	7.5%	3.5%	5.3%	3.2%	4.7%
%Δ per BGY	1.6%	0.4%	1.5%	—	1.4%	0.6%	1.0%	0.6%	0.9%

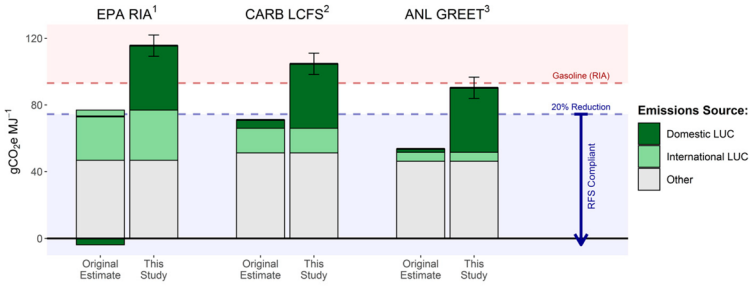
%Δ from BAU = percent change from BAU; i.e., the incremental effect of the 2007 expansion of the RFS; %Δ per BGY = percent change per BGY increase in ethanol demand.

fundamental evidence to guide this process and set realistic expectations for the contribution that current biofuel technologies can make toward climate mitigation and other environmental goals.

Materials and Methods

We estimated the domestic environmental effects of the 2007 US RFS by linking a series of empirical and explanatory models. First, we estimated the impacts of the RFS on the prices of corn, soybeans, and wheat. We then simulated, via independent models, the responses of crop rotations and total cropland area to the changes in crop prices. Last, we quantified the associated environmental outcomes by employing models specific to water quality indicators, nitrous oxide emissions, and ecosystem carbon emissions and updated existing life cycle estimates of ethanol's GHG intensity to reflect these findings.

Overall, our retrospective and purpose-built integrated assessment modeling framework has several advantages over previous projections and more generalized approaches. For example, 1) we utilize observed rather than predicted crop prices and land uses as a baseline factual scenario against which we compare our counterfactual scenario, thereby eliminating one (of the two) sets of assumptions, projections, and uncertainties required for assessment; 2) our estimates of the effects on crop prices and land use are based on empirical assessments of observed changes rather than partial or general equilibrium models that rely heavily on assumptions and prescribed parameters; 3) we use historic changes in crop prices, crop rotations, and cropland area to validate our econometric models' predictions and show strong temporal and regional fits between projected and observed changes; and 4) we utilize field-level remote sensing data to detect the location of actual LUCs—rather than rely on assumptions about the type, location, and characteristics of converted lands—and use this information to more accurately estimate the environmental impacts of conversion. We also implemented several model-specific



[1]U.S. Environmental Protection Agency (EPA) Regulatory Impact Assessment (RIA); Projection for 2022.
[2]California Air Resources Board (CARB) Low Carbon Fuel Standard (LCFS); Estimated from approved values for 2019, see SI Appendix.
[3]Argonne National Laboratory (ANL) Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model; Default values from 2020.

Fig. 3. GHG emission intensities for corn ethanol with and without updated domestic LUC emissions. Original estimates reflect GHG intensities of corn ethanol according to the US EPA RIA [projection for 2022 (35)], California Air Resources Board (CARB)'s Low Carbon Fuel Standard (LCFS) [estimated from approved values for 2019 (62); *SI Appendix*], and Argonne National Laboratory (ANL)'s Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model [default values for 2020 (63)]. Revised estimates (this study) replace the estimated domestic LUC emission from each source with those identified in this study. Our domestic LUC emissions estimate includes ecosystem carbon losses (including methane) from land conversion and on-site nitrous oxide emissions from additional fertilizer usage but excludes all other upstream and downstream emissions. Error bars represent 95% CIs for emissions from domestic LUC only (*SI Appendix*).

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Table 2. GHG emissions intensities for LUC, total ethanol, and reference gasoline

	kg CO_2e/mmBtu	g CO_2e/MJ	% change from gasoline
LUC emissions			
This study, domestic	40.9	38.7	—
EPA RIA*, domestic	−4.0	−3.8	—
EPA RIA*, international	31.8	30.1	—
CARB LCFS†, combined	20.9	19.8	—
GREET‡, domestic	2.1	2.0	—
GREET‡, international	5.7	5.4	—
Total ethanol			
RIA*	77.2	73.2	−21.4%
RIA* + this study	122.1	115.7	24.3%
LCFS†	74.9	71.0	−23.7%
LCFS† + this study	110.4	104.7	12.5%
GREET‡	56.6	53.6	−42.4%
GREET‡ + this study	95.3	90.3	−3.0%
Other			
RIA gasoline*	98.2	93.1	0.0%

*US EPA RIA; projection for 2022 (35).
†CARB LCFS; approved values for 2019 (62).
‡ANL GREET model; default values for 2020 (63).

advances to improve the resolution, specificity, and performance of each individual component of analysis. We briefly describe each step of our analysis and its integration below and provide the full details in *SI Appendix*.

Effects on Crop Prices. We used a partially identified vector autoregression model to assess the effects of the RFS on US crop prices. Our approach closely follows that of Carter et al. (46) to account for competing shocks in demand due to changes in inventory, weather, and external markets and extends the work beyond corn to estimate the impacts of the RFS on soybean and wheat prices. We also incorporate the RFS policy as a persistent shock to agricultural markets rather than a transitory shock, whose price impacts are different (*SI Appendix, Estimating Effects on Crop Prices*).

In our analysis, we compare observed market prices to a counterfactual BAU scenario without the expanded 2007 RFS, where BAU ethanol production satisfies only the volume required by the initial 2005 RFS. This volume is roughly equivalent to the amount needed to meet oxygenate requirements for reformulated gasoline under the 1990 Clean Air Act. Our analysis therefore estimates the effects of the 2007 expansion of the RFS program above what would have otherwise likely occurred to meet demand for ethanol as an oxygenate after ethanol replaced methyl tert-butyl ether as the main oxygenate additive. As such, we assume the pre-2007 trend of increasing ethanol use would have continued without the expanded RFS, albeit at a slower rate.

Additional factors such as the Volumetric Ethanol Excise Tax Credit or improved cost competitiveness may have also contributed to ethanol's growth. Our price effects are scalable, however, such that all land use, environmental quality, and GHG emissions that we report would remain the same on a per volume of ethanol basis, independent of the magnitude of demand change (within reasonable limit) or its source. Thus, our results also reflect observed outcomes from corn ethanol development in general, irrespective of whether such changes were driven by policy, markets, or other factors.

Effects on Crop Rotations. After modeling the price impacts of the RFS, we followed the approach of Pates and Hendricks to estimate how changes in crop prices affected crop rotations and the likelihood of planting continuous corn, continuous other crops, and corn–other crop rotations (49, 84, 85). We estimated a set of Markov transition models to separately estimate the probability of planting corn conditional on the crop planted in the prior season. One model estimates the probability of planting corn given corn was the previous crop, and the other estimates the probability of planting corn given a different crop was the previous crop. We then used these transition probabilities to estimate the probability of each crop rotation. To account for price response heterogeneity, we separately estimated these models for each major land resource area (MLRA) and major soil texture group. Advantages of our approach are that it explicitly accounts for the common practice of rotating crops and spatially heterogeneous responses to price across the country, as previous work shows that using aggregate data or ignoring price response heterogeneity can significantly bias estimates (84, 85). Furthermore, our model allows us to assess the location of environmental impacts as they relate to variation in price response.

To estimate the models, we built a spatiotemporal database using field boundary data (86–88) and associated information on annual crop type (89), soil properties (90), and climate (91) as well as crop futures and local spot prices (92). We then calculated the rotation probabilities for all fields greater than 15 acres that were in regions where 1) greater than 20% of the total area was cropland, 2) more than 10% of cropland acreage was planted to corn, and 3) greater than 50% of the cropland not planted to corn was planted to a crop for which prices were available (specifically wheat, soybeans, rice, and cotton). This set of criteria ensured adequate data were available to train each model, and our final sample included 3.6 million fields that accounted for 91.6% of corn acreage in the United States. Based upon results of the price impact modeling, we used a 30% persistent increase in the price of corn and 20% increases in the prices of soybeans and wheat to estimate, for each field, the change in probability of each rotation due to the RFS. We then derived area estimates using field sizes and summed the results across all fields and rotations (*SI Appendix, Estimating Effects on Crop Rotations*).

Cropland Area Changes. To assess LUCs at the extensive margin, we estimated the probability of transitioning between cropland and pasture or transitioning between cropland and CRP as a function of cropland, pasture, and CRP returns while controlling for soil and climate characteristics. We used a correlated random effects model to reduce concerns about endogeneity because the spatial variation in returns may be correlated with any omitted variables that affect land use transitions. Thus, our model is designed to better isolate the effect of changes in cropland returns on cropland transitions than other approaches that may confound differences in cropland returns across space with other unobserved factors that affect cropland transitions. We also account for the fact that land can only enter CRP when a sign-up is offered and can only exit CRP when the contract expires.

The model uses point-level land use transition data based on observed annual land use transitions in the National Resources Inventory (NRI) from 2000 to 2012. We then used the model to predict the change in transitions between 2008 and 2016 based on changes in prices (39). During this period, we predicted changes for 8 y, with the first transitions occurring between the 2008 and 2009 growing seasons. This approach may thus underestimate the total extensive land response to the RFS, as some land likely came into production prior to the 2009 growing season and after the 2016 growing season. In order to allow for geographic variation in the extensive response of land use to crop prices, we trained independent models for each of seven different land resource regions (LRRs) corresponding to aggregated MLRAs from the Natural Resources Conservation Service (*SI Appendix, Estimating Effects on Cropland Area*).

We then mapped observed LUC at field-level resolution during our study period following the general approach of Lark et al. (93) and using updated recommended practices (94, 95) to extend the analysis to 2008 to 2016 (37). These data were used to link the estimated extent of LUC associated with the RFS in each major LRR to specific locations of observed conversion for the purpose of enumerating environmental impacts. Thus, the high-resolution field data (37) were used only to identify the possible locations and characteristics of converted land, whereas the data from the NRI were used to estimate the magnitude of conversion and how much of it could be attributed to the RFS. This hybrid approach thereby combined the high certainty and long-term temporal coverage (prior to any RFS price signals) of the NRI data with the field-level specificity of the satellite-based land conversion observed during the study period (37, 94).

Nutrient Application and Water Quality Impacts. Rates of N and P application were developed using county-level estimates of fertilizer and manure application compiled by the US Geological Survey (96, 97), county-level estimates of area planted to specific crops from the Census of Agriculture (98), and typical fertilizer application ratios for the three major crop types (corn, soybeans, and wheat) from university extension publications (99). We then used these nutrient application estimates to drive a process-based agroecosystem model to simulate fluxes of water, energy, and nutrients across our study period for each crop rotation system across the United States as well as for each patch of converted land identified by the land transition model, following the approaches of Motew et al. (100) and Donner and Kucharik (41) (*SI Appendix, Estimating Water Quality Impacts*). To determine the impacts of the RFS from crop rotation changes, we multiplied the agroecosystem model outputs for each crop rotation by the change in its probability due to the RFS as determined via the econometric model described in the section *Effects on Crop*

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Rotations. To estimate the impact from cropland transitions due to the RFS, we assessed the relative differences in ecosystem outputs between cropland and noncropland for each individual transitioned parcel and multiplied each by the proportion of land transitioned within each LRR due to the RFS.

GHG Emissions. We modeled changes in N_2O emissions from fertilizer applications using the nonlinear nitrogen effect model (NL-N-RR) of Gerber et al. (101). For each change in crop rotation or cropland area due to the RFS, we used the associated change in N application to estimate the corresponding change in N_2O emissions. N_2O emission estimates were converted to CO_2e by assuming a 100-y global warming potential of 265 (102).

We estimated the ecosystem carbon emissions associated with RFS-related LUC using the methods of Spawn et al. (36). Carbon emissions from soil and biomass degradation associated with LUC were modeled for all observed conversions to cropland. In addition, a variant of the Spawn et al. model was created to assess forgone sequestration associated with reduced rates of abandonment. This model was structurally similar to that used for conversion to cropland but used a carbon response function (61) for conversion to grassland to estimate expected soil organic carbon accumulation over a 15-y period—the average length of a CRP contract. We thus assumed that any abandoned land would have been retired to the CRP and sequestering carbon for the duration of its contract. To attribute emissions to the RFS, we multiplied the combined net change in emissions from all observed LUC within a given LRR by the percentage of that region's observed LUC that could be attributed to ethanol under the RFS.

To estimate emissions per liter of increased annual ethanol demand, we followed the approach of the EPA (35) and allocated total ecosystem carbon emissions over a 30-y period. We then added these amortized ecosystem carbon emissions to the annual nitrous oxide emissions from crop rotation and cropland area changes to estimate total annual emissions. We divided total annual emissions due to the RFS by the increased annual demand in ethanol estimated in our price impacts model and subsequently converted to emissions per unit of energy equivalent using a heating value of 21.46 MJ/L (35).

Estimating Uncertainty. We quantified uncertainty at multiple points of our causal analysis framework including the price impact analyses, the crop rotation and cropland transition analyses, and the environmental impact modeling (*SI Appendix*, *Estimating Uncertainty*). Except for the price impacts, we propagated the uncertainty results throughout the connected components—from the land use models through to all subsequent environmental outcomes. All results are presented in the main text as 95% CIs, reported as [lower limit (0.025 quantile), upper limit (0.975 quantile)].

Data Availability. All national and regionally aggregated data are available in the main text and *SI Appendix*. All underlying field-level data aggregated to counties have been deposited in a permanent repository (https://doi.org/10.5281/zenodo.5794632). Code developed for and used in this study is available on GitHub (https://github.com/gibbs-lab-us/). All other study data are included in the article and *SI Appendix*. Previously published data were also used in this work (https://doi.org/10.5281/zenodo.3905242).

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"Analyzing the Downstream Impacts of U.S. Biofuel Policies"

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June 16, 2021

Abstract

Researchers have shown that U.S. biofuel policies raise grain prices, improving the welfare of grain producers. But, the downstream implications of those policies haven't received much attention. Indeed, by creating new demand-side competitors for feed inputs these policies also risk destructive effects on cattle producers in particular, who use corn as a major input component. We investigate the effects of biofuel policies on cattle markets along several dimensions, focusing on price dynamics and herd size. We find that, following adoption of the Renewable Fuel Standard (RFS) in the United States, (1) a one standard deviation increase in the crude oil price leads to a several hundred thousand head reduction in the U.S. Beef herd, and (2) steer production profitability exhibits both statistically and economically significant declines.

Keywords: Price Analysis, Biofuel Policy, Cattle, Futures Markets, Government Policy

Econ Lit Codes: Q14, Q18, Q48

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1 Introduction

Biofuel policy in the United States began with the Energy Tax Act of 1978, which provided a tax exemption for ethanol fuel blends at 100% of the gasoline tax (Kesan et al. 2012). During the 1990s, Congress expanded that support, first with the passage of the Clean Air Act (CAA) of 1990, followed by the Energy Policy Act of 1992, directing appropriations toward research into the production and commercialization of alternative fuels. Congress continued this support with a series of reforms in the later part of the decade (FAO 2008). These reform address commercial fuel blending, particularly with regard to Methyl-tert-butyl ether (MTBE). MTBE raises octane levels in gasoline and reduces fuel emissions. In response, in 2001, California announced a ban on MTBE. As a result, in 2003, California, the nation's largest commercial vehicle market phased out MTBE in favor of ethanol (McCarthy and Tiemann, 2006). Soon other states placed restrictions on the use of MTBE, resulting in a significant decline in the demand for MTBE as a fuel oxygenate and a significant increase in the demand for ethanol (Duffield et al., 2015). Following these environmental mandates, Congress directly intervened in the renewable energy market to promote biofuel production and adoption.

The American Jobs Act of 2004 introduced the Volumetric Ethanol Excise Tax Credit (VEETC), a tax credit of 51 cents per gallon of ethanol for commercial sellers. In 2005, Congress enacted the Renewable Fuel Standard (RFS-1). RFS-1 required 4 billion gallons of renewable fuel by 2006. In 2007, Congress expanded the mandate of the RFS-1 with the passage of the Energy Independence and Security Act of 2007, which stated that by 2009 domestic refiners must blend the fuel that Americans consume with 9 billion gallons of ethanol, with scheduled yearly increases to a 36 billion-gallon target by 2022 (Brown and Brown, 2012). This expansion is known as the RFS-2 (Yacobucci, 2012). Various observers rationalize government-imposed RFS mandates as pursuing a variety of objectives, including

reduction of GHG emission and reduction of the US dependence on foreign energy sources (Moschini, Cui and Lapan, 2012).

The most obvious effect of U.S. Renewable Energy Policy is that Americans now pour about thirty-six percent of the U.S. corn crop into their gasoline tanks (USDA, 2021). This new source of demand raises grain prices (see, e.g., Wright, 2014 & de Gorter et al., 2015) and more closely links them to energy markets. Carter et al., (2017) estimate that RFS policy increased the price of corn by 31% through 2019; Smith, (2019) extends the analysis of Carter et al., (2017) by including data from the 2016-2017 crop year as well as incorporating wheat and soybeans. He estimates the cumulative increase to the corn price over the life of the RFS-2 at approximately 30%.

However, the downstream impacts of biofuel policy on other agricultural markets remains effectively unexplored in the literature, even though feed (primarily corn) makes up approximately 60% of cattle production costs (Lawrence et al., 2008; Holgrem and Feuz, 2015). Industry advocacy groups routinely express concerns about the additional costs imposed by U.S. biofuel policies. The National Cattlemen Beef Association (NCBA), has filed three notable RFS volume waiver petitions to request suspension of annual biofuel mandates, on the basis of economic hardship (NCBA, 2012; Feinman, 2013). The petitions sought to exempt refiners from blend requirements, especially during natural disasters such as the 2012 drought, since blending commercial fuels results in higher feed costs for cattle producers during such periods. In 2008, Former Texas Governor Rick Perry pursued a volume waiver, requesting a 50% reduction in mandated biofuel volumes. He argued that the program's unintended consequences will lead to real economic damage to livestock producers and higher food prices (Schor, 2008). In 2012, a coalition of livestock farmers petitioned the EPA to reduce mandated biofuel volumes stating that, along with extreme weather conditions, the RFS will lead to significant herd liquidation (O'Malley and Searle, 2021). In addition, ten U.S. states submitted RFS waivers stating that the program could lead to higher food costs

and grain supply depletion. In each instance, EPA did not grant a waiver, concluding that the impacts of the program on livestock farmers did not meet their definition of severe economic harm (NLR, 2012).

In this article, we estimate the economic harm RFS-1 & RFS-2 causes domestic cattle producers along several dimensions. Specifically, we study how biofuel policies more closely link energy prices and U.S. cattle herd size, and how real returns fell permanently following RFS-1 implementation. In the next section, we provide an overview of the existing literature on the relationship between biofuel policy and food commodities. In section 3, we offer background information on the cattle industry. Sections 4 and 5 detail our data and analytical methods and results. Section 6 concludes.

2 Relevant Literature

Carter et al., (2011) and de Gorter et al., (2015) attribute the doubling of food commodity prices between 2008-2012 to the systemic change in U.S. biofuel policies–in particular, the introduction of the RFS-1, RFS-2, and MTBE ban. However, it is important to note that there is some contention surrounding the impact of biofuels on food commodity prices[1]. Nevertheless, several studies in the literature identify biofuel policy as an important contributing factor among many to the price boom of the late 2000s.

Studies examining the relationship between food prices and the demand for biofuels traditionally follow a time series or general equilibrium approach, but in general results are consistent across methods. We focus on the time series approach employed by Carter et al., (2017) and Smith, (2019) to analyze the impact on livestock markets. However, we briefly

[1]For example, others attributed the price boom to, e.g., increased demand for more resource-intensive foods in rapidly-developing nations (von Braun, 2007), financial speculation (see, e.g., Reguly, 2008)—even though the evidence supporting that view is–at best– mixed, and a combination of factors, including weather-related production shortfalls (Condon et al. 2015), U.S. monetary policy, and a leveling-out of crude oil production (Trostle, 2008).

discuss both methods here.

The first method relies on computable general equlibrium models to demonstrate the impacts of biofuel policies across the economy. For example, Chen and Khanna, (2013) use the BEPAM[2] to analyze the contribution of the RFS and other complementary policies (the VEETC and import tariffs) to corn and soybean prices along with sugarcane imports in the US in 2022 relative to a counterfactual scenario with no government intervention in the biofuel sector. They estimate a 4.7% increase in the corn price per billion gallon increase in ethanol production. In addition, they find in the absence of sugarcane tariffs, which were implemented to suppress competition with Brazilian sugarcane ethanol manufacturers, that 3.3 billion liters of ethanol would have been imported. (Hertel et al., 2010) use a different computable general equilibrium model built upon the standard Global Trade Analysis Project (GTAP) framework. They estimate a smaller effect of U.S. biofuel policies on the price of corn: approximately 1.3% per billion gallons of ethanol produced. However, they also find that acreage planted to coarse grains in the United States would rise by 10% as a result of biofuel policy mandates, while forest and pastureland areas of the United States would decrease by 3.1%. Therefore, even with potentially smaller price changes for corn consumers, ethanol expansion under RFS-2 has significant effects on the landscape of agricultural production in the United States. (Lapan and Moschini, 2009) build a simplified two-country general equilibrium model, where the energy and food sectors are linked. This competitive model assumes an upward sloping supply of corn with multiple uses: feed, energy, food, and export. They show that the ethanol mandate policy approach yields higher welfare than the ethanol subsidy. (Cui et al., 2011) adapt and extend Lapan and Moschini's model to make it more suitable for simulating the consequences of alternative policies. The extension recognizes that firms produce other products when they refine oil, in addition to gasoline (distillate fuel oil,jet fuel, etc.). The authors aggregate all non-gasoline output into

[2]Biofuel and Environmental Policy Analysis Model

a single good called petroleum by-products. Consistent with Chen and Khanna, (2013), Cui et al., (2011) estimate that corn prices should rise by 3.75% per billion gallons of ethanol produced. (Moschini et al., 2017) build a multi-market model of the U.S. supply of corn, soybeans, oil, along with the domestic and rest-of-world demand for food products and transportation fuels. They simulate their model under a no-RFS scenario, 2022 RFS-2 scenario, and optimal (second-best) mandates scenario. Compared to the no-RFS scenario, they find that current 2022 RFS-2 mandates increase corn prices by 3.6% per billion gallon of ethanol produced. At the low end, Gehlhar et al., (2010) found in a general equilibrium analysis that for every billion gallons of ethanol produced the price of corn will rise by 0.4–0.7%. In fact, their report suggests that the ethanol policy mandates and tax credit subsidies of the VEETC and RFS would result in greater household welfare by as much as $ 28 billion in increased consumption. However, this report is focused on consumer welfare impacts as they claim that the RFS-2 would impact food prices considerably less than it would impact farm commodity prices in the long term (i.e. by mandate objectives of 2022).

The second method we address relies on the time series approach developed by (Carter et al., 2017). They adopt a partially identified structural vector autoregression model to estimate the effect of the RFS on corn prices. (Smith, 2019) updates their model for corn with data through the 2016-17 crop year, and also applies the model to soybeans and wheat. Their models rest on the fact the RFS is a persistent rather than a transitory shock to agricultural markets. This distinction is important because persistent shocks have longer-lasting price effects than transitory shocks, and are signified by a structural break. Markets for storable commodities can respond to a transitory shock, such as poor weather conditions, by drawing down inventories, mitigating its effects. In contrast, inventories cannot insulate market participants from a persistent shock. (Carter et al., 2017) decompose the shock to crop inventories and spot prices owing to the increase in the demand for corn and soybeans by including impulse response functions for corn and soy futures prices and inventories. Their

results show that inventory demand shocks increase the futures prices. Their findings for the impact of U.S. ethanol policies aligns with the general equilibrium analysis results: they estimate that every billion gallons of ethanol produced raises the price of corn by 5.6% (95% CI– 0.009, 0.17). To account for the short-term and long-term response to shocks, Carter et al., (2017) include in their model the convenience yield, allowing them and Smith, (2019) to isolate RFS' persistent impact on agricultural commodities.

3 Cattle Market Background

To facilitate our discussion, we provide an overview of the modern beef industry, and offer important definitions as well as a timeline of production. We begin by defining the production inputs, and describe the production function for cattle producers. We then then describe input costs, focusing on feed, and the typical feed input mix of producers. We conclude with an overview of the beef supply chain. Finally, for context, we conclude this section with a brief summary of the beef cattle supply chain as well as general trends in cattle markets over the last few decades.

The cattle production function is made up of equipment and infrastructure, weather conditions, feed, supplemental nutrients, and veterinary resources. Equipment and infrastructure includes, for example, fencing, corrals for cattle handling and machines for forage production, and transporting cattle to market. Weather conditions affect cattle performance, e.g., extreme heat reduces an animal's ability to gain weight and leads to heat stress. Veterinary services ensure herd health and reproduction. And successful production of beef cattle necessitates good quality feed. In fact, feed is the principle component of all models of the production function for cattle (Heady et al., 1963; Lalman et al., 1993; Van Amburgh et al., 2008; Holgrem and Feuz, 2015). Specific feed rations depend the type of operation and the time of the year. For example, in the winter producers might opt for a low-energy ration

composed of primarily fibrous hay supplemented with more high-energy silage[3] and essential minerals (e.g. calcium, phosphorus, and potassium). On the other hand, in the spring and summer producers may adopt a more high-energy diet composed of feed grain to promote efficient weight gain in the herd. In terms of total digestible nutrients[4] (TDN), up to 70% of such a feed mix would come from feed grains (Lalman et. al., 1993; NRC, 2000) like corn, sorghum, barley, and oats. In the United States, corn is far and away the primary choice, accounting for more than 95% of total feed grain production and use (USDA, 2020). Byproducts of ethanol production (i.e. distillers grain) can be substituted for feed grain, and are primarily used in the Midwest and Great Plains[5]

As a result, feed represents the primary cost for a beef producer, accounting for 60% of the cost of production (Lawrence et al., 2008; Holgrem and Feuz, 2015). And since corn is the primary feed grain, its price changes play a dominant role in the cost of beef production. In fact, (Tonsor and Mollohan, 2017) show that the corn price is inversely related to cattle margins: as the price of corn increases, returns to cattle producers decrease. Therefore, the cattle market is highly susceptible to corn price volatility. Figure 1 shows the price of corn from 1983-2021. The period of corn price doubling is clearly visible, and while it does stabilize around 400¢/bushel toward the end of the 2010s, in nominal terms it remains well above prices observed during the 1980s and 1990s. Compounding this feed input cost rise is the significant increase in the cost of crude oil over the past 40 years. Figure 1 also shows the West Texas Intermediate (WTI) futures price over the same time frame. For the first half of the period, oil prices were relatively stable below $50 dollars a barrel. However, beginning in the early 2000s, they spiked and have remained elevated compared to their historical level. This translates into a higher cost of transportation for beef producers, packers, and

[3]"Silage" refers to grasses grown for forage and harvested at a relatively high moisture level; the most common types of silage include alfalfa and corn in the United States.

[4]"Digestible nutrients" is the proportion of feed that an animal can metabolize into their system

[5]Cottonseed, a byproduct of the ginning process for cotton, can also serve as a feed grain substitute (perhaps in times of high grain prices) since it is an adequate source of protein.

distributors. The long beef cattle production cycle (relative to annual crops, for example) increases the role of uncertainty with respect to investment,[6] and when coupled with higher feed and transportation costs places pressure on the domestic herd size. The second panel of Figure 1 shows that, since the late 1970s, the U.S. beef herd size fell from approximately 39 million head to 60-year low in 2014 of just over 29 million head. The industry attributes this steady decline to a variety of factors including drought years, market uncertainty, and packing capacity (Northen Ag. Network, 2020), with the high cost of feed as perhaps the main cause for cow herd shrinkage.

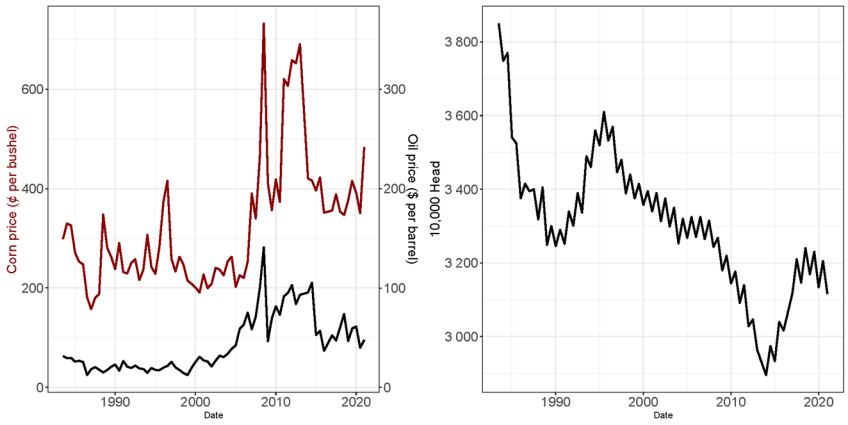


Figure 1: Beef Herd Size, Corn, and Crude Oil Prices 1983 - 2021
Source: USDA 2021 & Focus on Feedlots Newsletter, KSU 2020

[6]The natural cattle cycle, a process in which the size of the national cattle herd—including all cattle and calves—increases and decreases over time. This typically lasts between 8 to 12 years, with the last full cycle beginning in 2004. The herd size grew slightly over the next three years before increasing feed and energy prices led the herd size contracting sharply to a record low in 2014 (USDA 2021).

One sign of the disparate impacts of biofuels policy on up- and downstream agricultural producers is the difference in land price paths, which capitalize the value of production according to economic theory (Doye and Brorsen, 2011). Figure 2 shows that while cropland values nearly doubled in real terms sine the late-1990's, pastureland values have increased by a much smaller factor–just a few hundred dollars per acre. U.S. Government support for agriculture, codified every five years in the Farm Bill, provides crop producers with significant support through subsidized crop and revenue insurance programs, but little in the way of support for livestock producers. For example, the 2018 Farm Bill allocates almost $70 billion to crop insurance and commodity risk protection programs (CRS, 2019). Livestock producers do not receive the same level of support under the legislation. Even ad hoc programs, like direct assistance to producers to remunerate them for trade war damages is targeted to the producers of crops (Adjemian et al., 2019), not livestock.

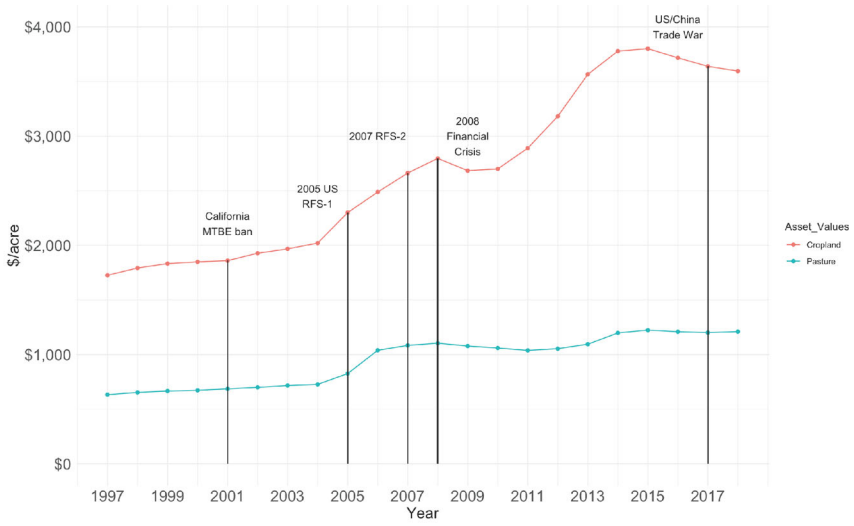


Figure 2: US Real Land Values 1997-2018
Source: NASS Land Asset Values Survey 2018

4 Data and Methods

Table 1: Summary Statistics: Structural VAR Herd Model

Statistic	N	Mean	St. Dev.	Min	Pctl(25)	Pctl(75)	Max
Crude Oil $/barrel	74	42.54	28.67	12.34	20.21	59.00	141
Corn ¢/bushel	74	323	128	157	232	385	732
Live Cattle $/cwt	74	86.19	25.93	55.97	65.79	102	166
Herd Size 10000 head	74	3,308	186	2,896	3,206	3,399	3,850

Source: NASS & CME 2021

To examine the impact of U.S. biofuels policy on the cattle industry, we use biannual (January and July) herd data from the National Agricultural Statistics Service (NASS) for the U.S. beef herd from 1970 to 2021. These data are available through the NASS Cattle Inventory Report[7]. We match our herd data with the average of the nearby daily futures prices for relevant CME (Chicago Mercantile Exchange) commodity prices in the intervening period up to each inventory report. For example, the Cattle Industry Report is published at the first of the month in January and July. Therefore, we average the preceding six months of futures prices to correspond to the herd average provided by the report. For the nearby futures prices, we use the front-month closing price for corn, live cattle, and West Texas Intermediate (WTI) crude oil. By matching this way, we generate 74 observations for the time period July 1983 to January 2021. Table 1 presents summary statistics for these series. Over the period of observation, the average size of the U.S. beef herd was 33 million head, which is down from the early 1970s high of about 40 million. The corn price experienced dramatic changes over this same time period, rising to almost $ 8.00 per bushel following the RFS. Crude oil follows a similar trend, rising in the early 2000s to a record high in 2008-09 before collapsing with the recession only to bounce back in the 2010s. Live Cattle, however, remains steady relative to the other series with short cycles of highs and lows throughout the 2000s and 2010s.

Table 2 presents the summary statistics for the cattle market returns data. Feeding cost of gain[8] is reported in the Focus in Feedlots newsletter[9] produced by Kansas State University (KSU). Feeder cattle prices for Kansas are reported by the Livestock Marketing Information Center (LMIC)[10]. Feeder cattle are cattle on feed that have yet to reach marketable weight. Their prices are reported for different weight categories (e.g., 600 to 700 lbs., 700 to 800

[7]The report was suspended in 2013 and 2016 due to sequestration
[8]An industry efficiency measure defined as the total feed cost divided by total gain in lbs.
[9]Focus on Feedlots Newsletters
[10]LMIC website

lbs., and 800 to 900 lbs.). We use this information along with feeder weight reported in the Focus on Feedlots newsletter, Kansas State University, to compute the feeder price for each month. Fed (or finished) cattle prices for steers in Kansas are reported by the LMIC. The "price ratio "is the feeder to fed cattle price ratio. Again, feeder cattle are distinct from fed cattle in that fed cattle have reached maturity (approx. 1100 lbs.) and ready for market, while feeder cattle are still maturing but can be put on feed in feedlots for finishing. Feed conversion is also reported in the Focus on Feedlots newsletter, Kansas State University, where the "feed conversion rate" is defined as the amount of feed input divided by the total mass of the fed cow/steer at finishing or its dressed (post-slaughtering) weight. In addition, the newsletter reports an inventory price for corn and alfalfa, as averaged over the previous 5 months–an appropriate measure for the feed cost of production. Simulated net returns per head of cattle producers are computed by subtracting feeding cost of gain and interest cost from gross returns (number of cattle marketed multiplied by the price). According to table 2, the average net returns are negative, but note that cattle sales are not constant over time. Sale weight, feeder weight, feeding cost of gain, and days on feed (for interest cost computation) are from the Focus on Feedlots newsletter, Kansas State University. We use the operating interest rate from the Kansas City Federal Reserve, a readily available interest rate for short-term assets.

Table 2: Summary Statistics: Net Returns and Feed Costs on Cattle

Statistic	N	Mean	St. Dev.	Min	Pctl(25)	Pctl(75)	Max
Net Returns $/head	252	−35.26	131	−521	−105	35.99	353
Feed Cost of Gain $/cwt	252	74.73	20.63	43.01	54.11	85.76	134
Price Ratio	252	1.20	0.13	0.82	1.10	1.27	1.70
Feed Conversion	252	6.04	0.21	5.62	5.90	6.15	7.08
Corn Price $/bushel	252	4.00	1.51	1.96	2.72	4.36	7.96
Alfalfa Price $/ton	252	133	45.84	59.33	102.84	153	242
Feeder Price $/cwt	252	124	35.60	72.76	96.76	146	240
Fed Price $/cwt	252	103	24.78	63.15	84.36	121	171

Source: LMIC & KSU 2020

We investigate whether the observed variation (and decline) in beef herd size is attributable to changes in U.S. biofuels policy by (1) analyzing the counterfactual (no VEETC, RFS, or MTBE ban i.e. business-as-usual) time series for herd size, and (2) searching for structural breaks in the beef herd series, especially in and around the critical dates of 2001, 2004, 2005, and 2008. After identifying structural breaks in the herd size, we split our sample to estimate the relationship between beef markets and energy before and after relevant policy changes. We implement the procedure described in (Bai and Perron, 2003) for simultaneous estimation of possibly multiple breakpoints. The distribution function used for the confidence intervals for the breakpoints is given in (Bai, 1997), and the objective is minimize the triangular RSS matrix, which gives the residual sum of squares for a break segment. We then use the same procedure to search for breaks in the net returns to feed and fed cattle producer data.

4.1 Structural VAR Model

We estimate the impact of biofuel policies on beef herd size, corn, oil, and cattle prices with a recursive structural VAR model. Our model extends the approach of Carter et al., (2017) and Smith, (2019) to include cattle. First, we define $\mathbf{y}$, as a set of endogenous variables $\mathbf{y}_t = (\text{oil_fut}_t, \text{corn_fut}_t, \text{cattle_fut}_t, \text{herd_size}_t)$. The $VAR(p)$ process for this set of endgogenous variables is:

$$\mathbf{y} = A_1\mathbf{y}_{t-1} + \cdots + A_p\mathbf{y}_{t-p} + \mathbf{u}_t \tag{1}$$

A_i are (4×4) coefficient matrices for $i = 1, \cdots, p$ lags and $\mathbf{u}_t$ is 4-dimensional white-noise process. We select an autoregressive lag order of 2 from the Schwarz information Criterion (SIC) for our $VAR(p)$ process (Pfaff 2008). Equation (1) is then a reduced form model. We

can then define a structural form model as:

$$A\mathbf{y} = \bar{A}_1\mathbf{y}_{t-1} + \cdots + \bar{A}_p\mathbf{y}_{t-p} + B\epsilon_t \tag{2}$$

ϵ_t are white-noise structural errors, and $\bar{A}_i$ are structural counterparts to the coefficients in Equation (1). B is the structural coefficient matrix for the error term. This matrix captures the impact of "structural shocks" to our endogenous variables, or true independent innovations rather than correlations among the variables in the model. We impose restrictions on B to simulate the impact of the structural shocks. Our restriction matrix B is,

$$\begin{pmatrix} b_{1,1} & 0 & 0 & 0 \\ b_{2,1} & b_{2,2} & 0 & 0 \\ b_{3,1} & b_{3,2} & b_{3,3} & 0 \\ b_{4,1} & b_{4,2} & b_{4,3} & b_{4,4} \end{pmatrix} \tag{3}$$

which implies oil prices (b_1) impacts corn (b_2) and cattle (b_3) prices as well as beef herd size (b_4) contemporaneously; corn impacts only cattle prices and herd size, and oil prices at a lag; cattle prices only impacts herd size, and oil and corn prices at a lag. These restrictions allow model identification by the Cholesky decomposition, which uses a recursive method to solve for the elements of B (Sims, 1980; Sims et al. 1990). This is a logical set of restrictions given that 40% of the U.S. corn crop is used for ethanol production, and the life-cycle of the average fed cattle on market is approximately 2 years, much longer the growing season for corn.

5 Results

We find that positive crude oil and corn price shocks reduce the beef herd size for up to several years. In particular, our impulse response functions in figure 3 imply that a one standard deviation increase in the price of oil ($\approx$ \$26/barrel) can produce a 400,000 to 600,000 head reduction in the U.S. herd size ($\approx$ 0.3% of the mean herd size over the period of observation). These results support the claim of the NCBA and other livestock industry groups that cattle liquidations can result from government intervention to promote the production and adoption of biofuels, if those policies raise the price of feed.

Other relevant impulse response results in figure 3 indicate that oil shocks affect corn prices, as expected. Specifically, our impulse response results imply that a standard deviation increase in the price of oil results in a 5.5% increase in the futures price of corn for almost eight periods or 4 years (assuming we divide the impulse response estimate for corn by the average price of corn during the 2008-12 food commodity price boom). This is consistent with the findings of Carter et al., (2017) and Smith, (2019). And, it implies that an expanding demand (or tight supply) for oil itself raises the cost of cattle production and pressures herd size downward, but also does so indirectly via its affect on the price of corn.

Method 1: Recursive identification

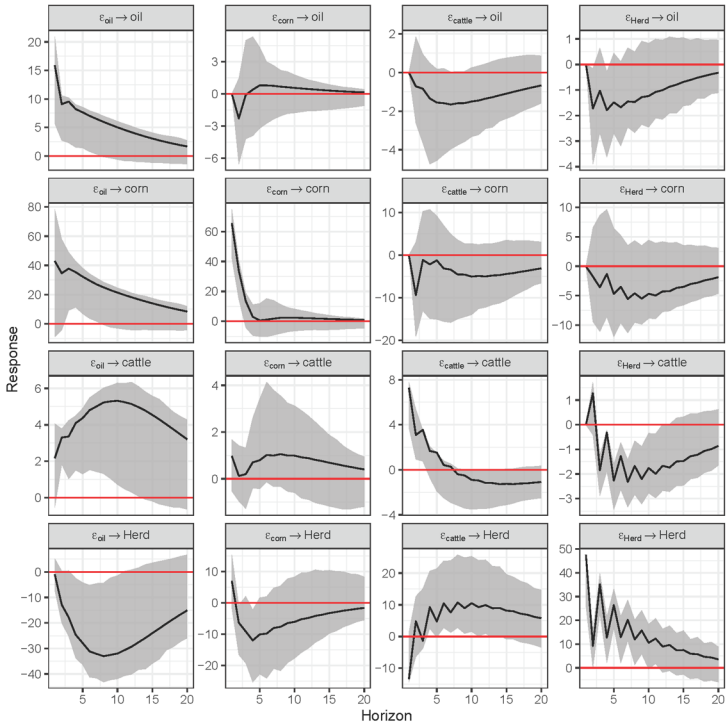


Figure 3: Impulse Response Functions (IRF): Simulated Shocks to SVAR components under Recursive Specification, 1983-2021

Source: Author calculations based on data sourced from NASS and CME 2021

Note: IRFs are generated from the estimated **B** matrix for 30 steps ahead. Grey 95% Confidence bands are generated using moving-block bootstrap method with 500 runs.

5.1 Counterfactual vs. Actual

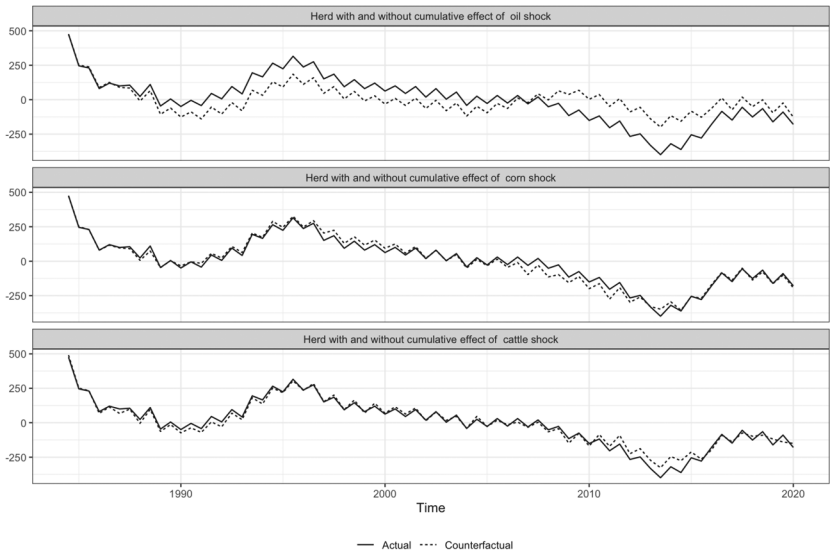


Figure 4: Evolution of de-meaned Beef Herd Size with and without corn,energy, and own-price shocks

Source: Author calculations based on data sourced from NASS 2021
Note: Counterfactual constructed from Recursive Identification Results

Similar to Smith, (2019), we present in Figure 4 the de-meaned beef herd series with and without the effects of shocks to crude oil, corn (the primary feed input), and own price. Corn and crude oil have the largest cumulative impact on beef herd beginning in the early 2000s. The first panel shows the historical decomposition for oil on herd size over our sample time period. Beginning in the mid-2000s, the observed herd size is above the counterfactual series, implying that the cattle herd benefited from depressed oil prices (recall Figure 1)–

which lowered industry production costs–until the mid-2000, when the U.S. government enacted significant policies to promote biofuel production and adoption. Beginning at that time, the counterfactual herd size series runs substantially higher than the observed series implying that the the spike in oil prices during the 2000s lowered the U.S. herd size, as cattle producers were forced to both pay higher prices for the oil they used in production and compete with ethanol producers for feed inputs. Figure 4 offer suggestive evidence that the transition in the crude oil market from low to high prices may have coincided with a structural break in the beef herd. Using the Bai-Perron procedure, we identify structural breaks in the beef herd series at July 1988, January 1994, July 1999, and July 2008. Test results are given in Table 3.

Table 3: Structural Break Test Beef herd Series

Break Point	10% value	90% value	RSS	BIC
July 1988	January 1988	July 1992	974825.4	960.6
January 1994	January 1993	July 1995	870396.5	960.6
July 1999	January 1999	July 2000	759681.6	958.9
July 2008	July 2007	January 2009	678299.5	959.0

Notes: Computed using procedure described in Bai and Perron (2003)

Figure 5 visualizes the identified structural breaks. These breaks coincide with significant events in the evolution of the U.S. beef herd. The 1988 break aligns with the start of the US-EU beef dispute over the use of hormones in the production process. The E.U. ban on the importation of hormone treated beef, resulted in the U.S. placing retaliatory tariffs on E.U. imports to the (AFB, 2019); unsurprisingly, the domestic herd rises beginning then. The 1994 break in the figure corresponds to the peak of the beef cattle price cycle, when feedlots swelled with an oversupply that resulted in a decline in the cattle price (Hughes, 2001). The 1999 break represents the year California sought its first waiver for the blending of MTBE in its commercial fuels, marking the beginning of the domestic shift towards ethanol as the

sole oxygenate used in the blending of commercial fuels. Finally, the 2008 break directly corresponds to the implementation of RFS-2 legislation (Duffield et al., 2015). From the standpoint of our analysis, the 1999 and 2008 break are of primary interest. These dates relate to fundamental shifts in U.S. biofuel policies, while the two previous breaks correspond to trade issues and market cycles for cattle. Therefore, we split our sample into two periods: (1) July 1983 to July 2000; (2) January 2001 to January 2021. For robustness, we compare our results to intentionally splitting our sample in 2004, coinciding with the adoption of the VEETC and immediately preceding the RFS-1 and RFS-2 implementation. This latter split generates results (available in the Appendix) consistent with our headline findings.

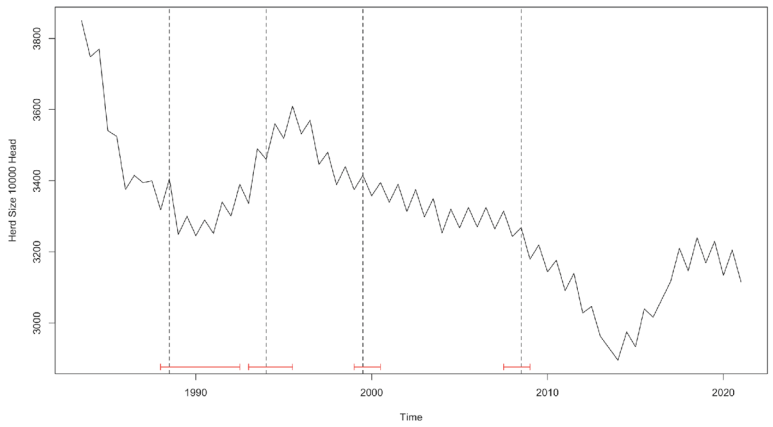


Figure 5: Structural Breaks U.S. Beef Herd 1983-2021
Source: Author calculations based on data sourced from NASS 2021

5.2 Sample Split: Pre and Post 2000

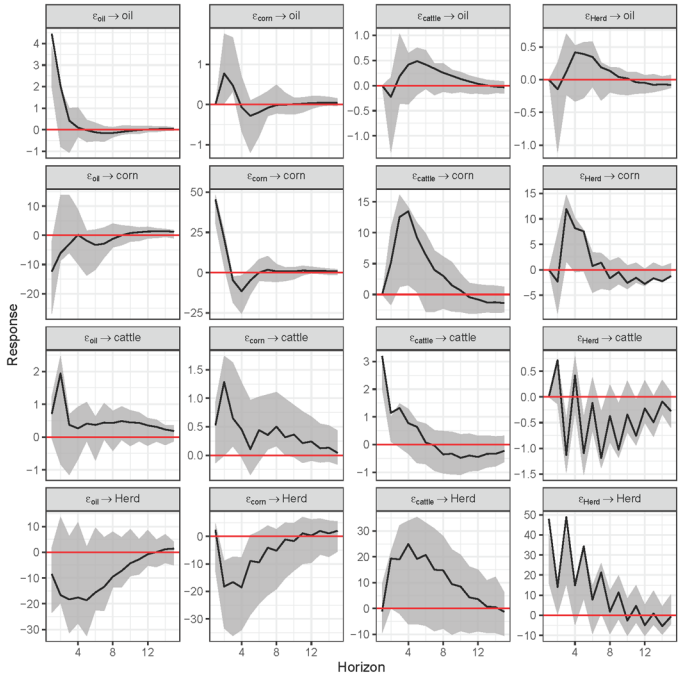


Figure 6: Sample Split pre-2000 impluse response function under recursive specification
Source: Author calculations based on data sourced from NASS and CME 2021
Note: IRFs are generated from the estimated **B** matrix for 15 steps ahead. Grey 95% Confidence bands are generated using moving-block bootstrap method with 500 runs.

Figure 6 presents the impulse response functions generated for data in the period July 1983 to July 2000. Unlike the total sample response functions in Figure 3, shocks to the crude oil prices, although suggestive, do not translate to significant decline in herd size (at the 95% level) before the MTBE ban and subsequent adoption of the RFS-1. On the other hand, corn price shocks have clearly significant, negative impacts on herd size even prior to

the MTBE ban–as expected since corn is the primary cost of feed.

Figure 7 depicts the impulse response function for the post-2000 era. Unlike in Figure 6, shocks to crude oil prices generate a significant decline in the domestic herd size, representing an important shift in energy and livestock markets. Our results, especially with regard to corn and oil, are consistent with the impulse response functions generated by of Carter et al., (2017) and Smith, (2019). In Figure 6, prior to the break, the impulse response of herd size to oil is not significant at the 95% level. However, in Figure 7, after the break, oil has a clear, significant negative impact on herd size. Furthermore, the oil shocks correspond to significant increases in the corn futures price after the break, consistent with the results of Carter et al., (2017) and Smith, (2019). For robustness, the impulse response function for the own-price and herd size on itself is unchanged before and after the break. This suggests that the adoption of the VEETC, RFS-1, and RFS-2 established a stronger link between cattle and energy markets. A sudden increase in the price of oil drives down the herd size in the short run. In addition, according to Figure 7, a positive corn price shock has a stronger (at the mean) and more persistent negative impact on herd size after the break than before it, lasting more than 8 periods (4 years), while before the break the confidence bands cross the vertical axis at about 4 periods, or around two years.

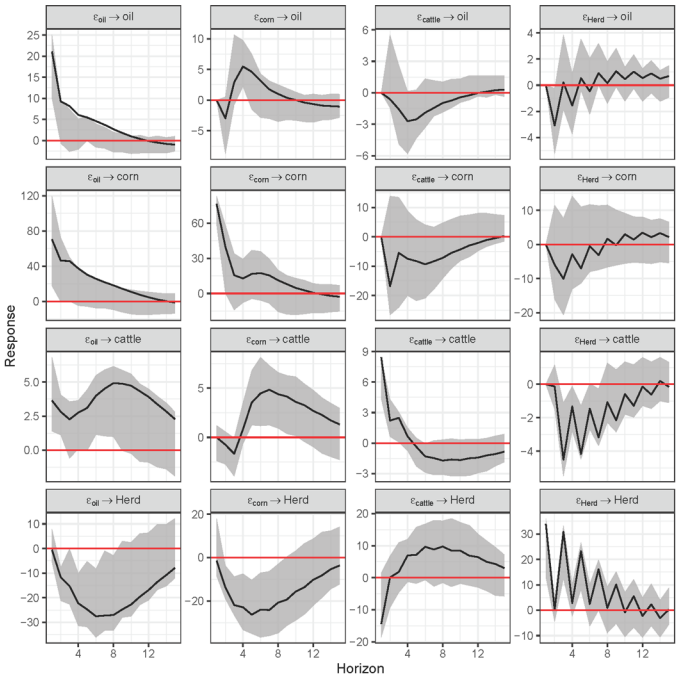


Figure 7: Sample Split post-2000 impulse response function under recursive specification
Source: Author calculations based on data sourced from NASS and CME 2021
Note: IRFs are generated from the estimated **B** matrix for 15 steps ahead. Grey 95% Confidence bands are generated using moving-block bootstrap method with 500 runs.

5.3 Structural Break: Net Returns

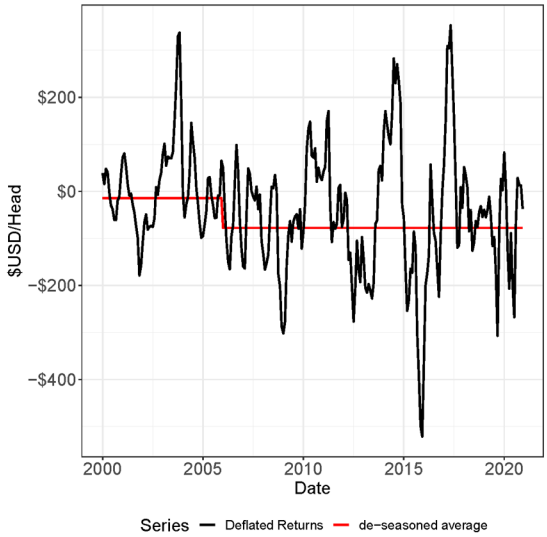


Figure 8: Deflated Net Returns $ per head
Author calculations based on data sourced from KSU and LMIC 2020

Finally, we consider the impacts to producer profitability using our simulated returns series. Following the Bai-Perron procedure, we identify a break point of October 2004 on the net returns to cattle (Bai and Perron, 2003). We then test the date of January 2006, the first month of the year after the RFS was passed. Table 4 details the test results. Since 2006, the average simulated return per head to steer producers at representative Kansas feedlots has decreased by approximately $77 per head. Figure 8 shows the deflated series of net returns along with the de-seasonalized average value of the series. We interpret this finding to mean that, in addition to making the domestic cattle herd more sensitive to crude oil and corn price shocks, U.S. biofuel policy has also adversely impacted cattle producer revenue.

Table 4: Structural Break Test Cattle Net Returns

Date	Test Statistic	$\lvert t \rvert$-value	p-value
October 2004	−73.70418	2.574709	0.0106
January 2006	−77.65414	2.306100	0.0220

Notes: Computed using procedure described in Bai and Perron (2003)

6 Conclusions

By expanding ethanol production, U.S. biofuel policy increased the demand for feed grains (especially corn) and raised their prices. But those policies also risked destructive effects on downstream entities by creating new demand-side competitors for feed inputs. Cattle producers, who use corn as a major input component, were most exposed. Our results confirm that–post-RFS implementation–sudden, unexpected changes to the prices of corn and oil pressure ranchers to reduce the domestic herd size. We also show that U.S. biofuel policies had both economically and statistically significant negative impacts on feedlot net returns.

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7 Appendix

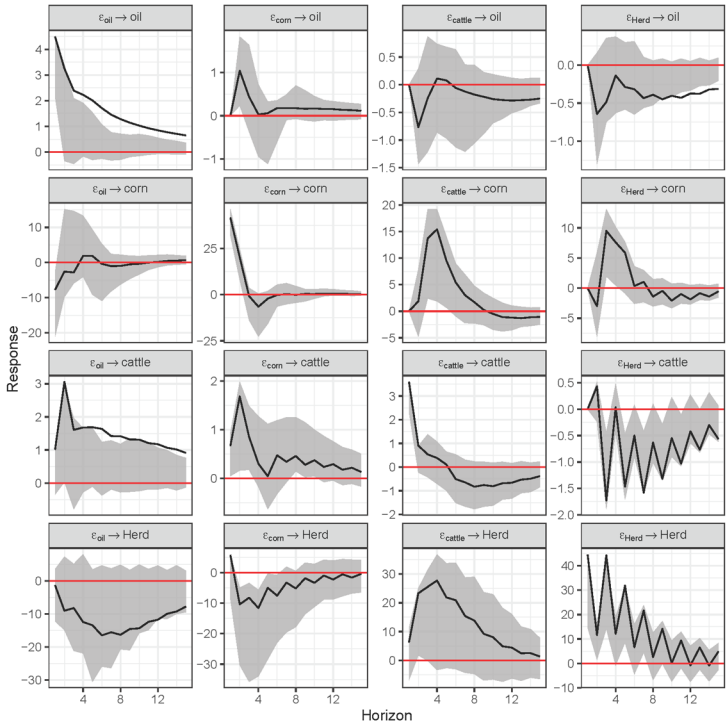


Figure 9: Sample Split pre-VEETC (2004) impulse response function under recursive specification

Source: Author calculations based on data sourced from NASS and CME 2021

Note: IRFs are generated from the estimated **B** matrix for 15 steps ahead. Grey 95% Confidence bands are generated using moving-block bootstrap method with 500 runs.

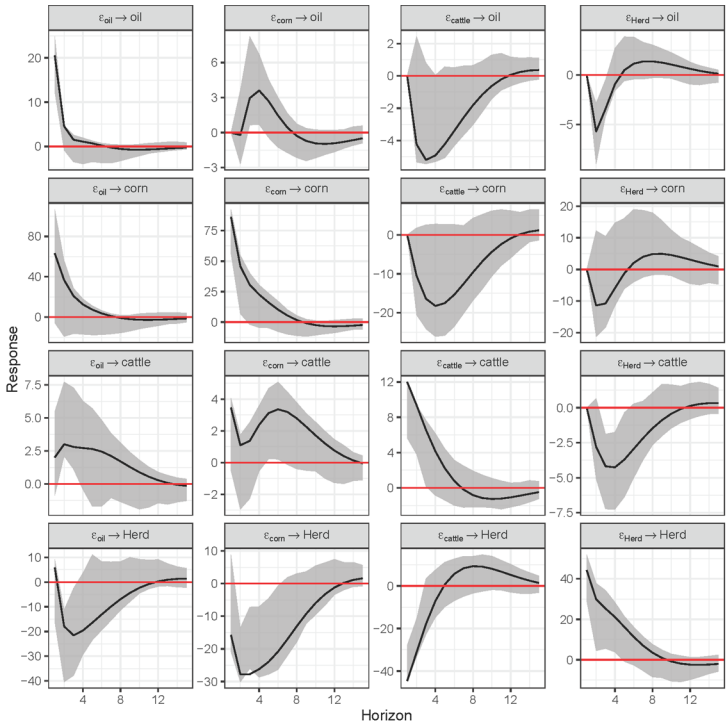


Figure 10: Sample Split post-VEETC (2004) impulse response function under recursive specification

Source: Author calculations based on data sourced from NASS and CME 2021

Note: IRFs are generated from the estimated **B** matrix for 15 steps ahead. Grey 95% Confidence bands are generated using moving-blook bootstrap method with 500 runs.

Senator LUMMIS. Thank you.

Senator CARPER. You are welcome.

Senator LUMMIS. Thank you very much. We have already heard testimony that the RFS mandate is adding about 28 to 30 cents a gallon to the wholesale cost of gas on average, and of course, at a time when fuel prices are extremely high and inflation is extremely high, it works a hardship on consumers. I believe we should look at every avenue to provide relief to consumers.

When I am in Cheyenne, on the ranch I grew up in, in the house I grew up in, I live right next door to a small refinery that lost its small refiner exemption. Furthermore, they were unable to, when refining for hydrocarbons, they were absolutely unable to purchase non-hydrocarbons to blend to meet the renewable fuel standards.

So, they converted the oil refinery to a refinery that now refines soybean oil. That refinery in our little town, in the State with the smallest population in the Nation, went from 260 livable wage jobs to 60 livable wage jobs. We lost 200 employees in Cheyenne, which is a huge number in our little community.

This has had an enormous impact on our community, and this happened during the previous Administration's tenure. I didn't see them slow walking the loss of the small refiner's exemption. I saw them putting the hammer down and costing small communities like mine hundreds of jobs.

Ms. Koch and Mr. Pugliaresi, when Congress created the biofuel mandate, we predicted that the program would disadvantage small refineries, and of course it has. It increasingly precludes refineries from selling the products they produce and requires them to buy products they don't produce, if they can get them. This squeezes the smallest firms first and most severely. Higher cost producers are harmed the most and first in time.

So, is this an effort to just make sure that, much as we did with banks, you are too big to fail or too small to succeed? In the case of small refiners, are they too small now to succeed?

Mr. PUGLIARESI. Senator, we think about the American refining complex. We traditionally had a lot of oil production produced and processed on the Gulf Coast, and then the products moved up the continent. But of course, with the emergence of production in North Dakota and the energy independence in the U.S., our small refiners and regional became much more important. I think they provide a vital role.

And as I have said, I think the solution remains in order for all these different facilities with their different cost structures and their different markets to adapt, they need an open market, and the fundamental problem they all face is these mandated requirements to blend to certain targets, which do not necessarily yield any benefits even to the farmers.

The program is, as I said, we are fighting over very small volumes. If we were to open it up and have some broad support for moving biofuels forward, we would all be a lot better off. These kinds of dislocations would tend to disappear.

Senator LUMMIS. Ms. Koch, same question.

Ms. KOCH. Senator, I really appreciate your question. It reminds me of something one of my small refineries said to me: We dance between the toes of giants. What that means is, the smallest refin-

ery in Cheyenne, Wyoming, the smallest refinery in Newell, West Virginia, the smallest refinery in whatever rural community, from Pennsylvania to California, danced between the toes of giant, integrated, multinational oil companies until the Renewable Fuel Standard came along and said, you know what, we are going to tilt competition in favor of the large, integrated oil companies, but don't worry, we have got your back.

Congress said specifically, we recognize that the volume mandates and the inability of small refineries to have access to capital to become large, integrated oil companies that don't have access to pipelines, that disproportionately produce diesel fuel, don't have access to blend stocks, don't worry, we have got your back. You will be OK. We can provide an exemption.

Small refineries blend every drop of blend stock they possibly can, but they don't always have access, and they don't always have the ability, so what happens is that they are captive buyers in a wildly inflated RIN market. And that is how they are harmed.

I just want to be clear. When we talk about 2019, 2020, and 2021, where EPA has proposed to deny hardship relief, not one more drop of renewable fuel can be blended. So what we are talking about is EPA compelling small refineries to make massive wealth transfers to large, integrated oil companies because they don't have access to feedstock, because they cannot blend. It is un-American.

Senator LUMMIS. That is, I think, that should be the focus of some of the work that we do to have a better Renewable Fuel Standard Program, because we are just assuring that only the big, integrated companies will succeed, and all of the small businesses will fail. They are, once again, moving people out of small, rural communities and into the bigger areas that have the bigger refineries. It is happening in so many industries that it is having a profound effect on America's jobs and demographics.

There has to be a way to encourage renewable fuels at the same time that you don't make it all about the small fail and the big survive and thrive.

Thank you, Mr. Chairman. I yield back.

Senator CARPER. Thank you very much for being here, and for those questions.

Senator Duckworth, have you joined us yet on Webex?

Senator DUCKWORTH. Yes, I have, Mr. Chairman.

Senator CARPER. All right, Senator Duckworth, you are recognized, please. Thank you.

Senator DUCKWORTH. Thank you.

Ms. Skor, some of the comments made in today's hearing demonstrate there is seemingly no end to the list that opponents the RFS Program will seek to pin on American biofuels. Critics now appear to be blaming biofuels for rising retail gas prices, notwithstanding the reality that what consumers pay at the pump is largely determined by a, oil prices, and b, basic supply and demand.

Ms. Skor, could you address the claim that RIN prices and biofuel production are somehow responsible for increasing retail gas prices?

Ms. SKOR. Thank you, Senator, and yes, those are false claims. So, the price of the RIN has no bearing on the price of fuel at the

pump. Those are entirely separate markets. The dominant factor driving the price of fuel for consumers at the pump is the price of crude oil in addition to supply and demand. That is something that is affirmed by our government agencies and other modeling.

What I think what is really important to understand is the role of biofuel in bringing down the price of fuel for the consumers. The evidence today is the price of E15. Consumers in 31 States today, they can go up to the pump, and they could put in standard 87. That is a 10 percent blend. Some of them could choose an 88 octane. That is a 15 percent blend.

When they have a little bit more ethanol, that actually brings the price down. They are saving up to 10 cents per gallon. There are also stations where you can buy zero percent ethanol. There, you are paying a premium up to 50 cents not to have ethanol. So most assuredly, biofuels like ethanol help bring down the cost of gas prices.

Senator DUCKWORTH. Thank you. Ms. Skor, based on how big oil describes the burdens of purchasing RINs, it is impressive that oil refiners survived the bipartisan enactment of the RFS more than 15 years ago. My understanding is that EPA, under the last three Administrations, the American Petroleum Institute, and numerous individual oil companies are all on public record confirming that oil refiners, large and small, recover RIN costs downstream and are therefore not irreparably harmed by the amount of money they pay to acquire RINs.

Could you help us understand how, despite the arguments of big oil over many years, oil refiners have managed to purchase RINs and stay in business?

Ms. SKOR. Thank you for the question. Yes, the RIN affords refiners flexibility in terms of how they demonstrate compliance with the RFS. They can blend biofuel, like ethanol, and they can hand in a RIN, or they can purchase a RIN. So they have got the flexibility to be able to do this. And the RFS has been in place since 2007. So we have had more than a decade for the business to understand their annual obligations and make business decisions accordingly.

Again, important to understand, the RIN marketplace and the volatility that you see when you have refiners who are choosing not to blend and wait until the eleventh hour, and then seek some type of exemption or waiver or extension from the agency, I think that is really where you are seeing the volatility come into play. But the bottom line is when it comes to consumer price at the pump, the more biofuel, the more they are going to save.

Senator DUCKWORTH. Thank you, Ms. Skor.

Mr. Chairman, I would like to ask unanimous consent to enter into the record EPA analyses from 2015, 2017, and 2021 that confirm what Ms. Skor just explained, along with two documents that counter the recent study that has garnered attention this week, one from the Renewable Fuels Association and another from the National Corn Growers Association indicating, among other things, that the USDA found that ethanol's carbon intensity was 39 percent lower than gasoline, and according to the EPA, the RFS has not expanded cropland; it has, in fact, decreased them by increased efficiency on existing cropland, not by expanding acreage. And ac-

cording to the USDA, the amount of fertilizer required to produce a bushel of corn has fallen dramatically in recent decades since the creation of the RFS.

Senator CARPER. Is that your unanimous consent request?

Senator DUCKWORTH. Yes.

Senator CARPER. Is there objection?

Hearing none, so ordered. Thank you.

[The referenced information follows:]

A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects

Dallas Burkholder, Office of Transportation and Air Quality, US EPA
May 14, 2015

Executive Summary

In 2013 the price of renewable identification numbers (RINs) for renewable fuels generated under the Renewable Fuel Standard (RFS) program increased significantly. This document examines available data in an attempt to describe and explain the factors that caused this increase in the price of one variety of renewable fuel (D6) RINs, and the impact this increase in RIN prices may have had on retail fuel prices. We also examine the impact of high RIN prices on merchant refiners (i.e. refiners who do not blend the majority of the petroleum products they produce with renewable fuels), some of whom argue that they are disadvantaged relative to integrated refiners (i.e. refiners who blend a volume of petroleum products with renewable fuels greater than or equal to the volume of petroleum products they produce) by high RIN prices. For the purposes of this document we have primarily considered available data from 2013, and have assumed constant renewable volume obligations (RVOs). This document does not quantify the total cost of the RFS program to consumers or other parties. We acknowledge, however, that the program is likely to have a cost if the cost of renewable fuels is greater than the petroleum based fuels they replace on an energy equivalent basis and if this cost outweighs the overall decrease in the cost of transportation fuel that results from increased fuel supply.[1]

In examining the available data we found that the rise in D6 RIN prices can largely be explained by the increasing total renewable fuel requirement of the RFS program. For the first time in 2013 this standard was established at a level beyond what could be achieved by the blending of ethanol as E10. This meant that the D6 RIN price was largely driven by the marginal cost of blending and marketing ethanol as E85, or the cost of blending other non-ethanol renewable fuels where available, since nearly all gasoline sold in the United States already contained 10 percent ethanol. The demand price for ethanol sold in an E85 blend is significantly less than the demand price for ethanol sold as an E10 blend, as the lower energy density of the fuel, and therefore lower fuel economy of a vehicle operating on E85, are more noticeable in higher level ethanol blends. Alternative fuel choices to E85, such as E10, are also widely available, giving consumers the opportunity to purchase the lowest cost fuel. With the exception of two brief spikes in the price of D6 RINs, which may be the result of the market adjusting to new supply and demand realities,[2] the D6 RIN

[1] Several parties have credited the increased availability of renewable fuels with a decrease in the market price of petroleum derived fuels (relative to a scenario with no renewable fuels) as renewable fuels increase the global supply of transportation fuel. While we acknowledge that increasing available volumes of renewable fuels may have had some effect on global petroleum prices, there is much uncertainty surrounding the magnitude of this impact and quantifying it is beyond the scope of this document.

[2] These price spikes, reported by Oil Price Information Service (OPIS), may overstate the average RIN price as many RINs are purchased through long term contracts or acquired when attached to renewable fuels. The prices reported by OPIS are more reflective of the price for separated RINs in the spot market.

prices in 2013 generally reflect what would be expected as the demand price for ethanol shifts from a volumetric relationship with gasoline, as was the case for E10, to an energy equivalent relationship with gasoline, as is expected to be the case for E85. We do not find evidence that the price of D6 RINs was driven by scarcity pricing,[3] as some have suggested.

While RIN prices were significantly higher in 2013 than in previous years, we did not see, nor would we expect to see, a corresponding net increase in the overall retail price of transportation fuels across the entire fuel pool. This is because the RIN price, rather than acting as an additional cost, generally acts as a transfer payment between parties that blend renewable fuels and obligated parties who produce or import petroleum-based fuels and are required to obtain RINs for compliance purposes.[4] RINs are generated by renewable fuel producers and sold attached to volumes of renewable fuels to fuel blenders or obligated parties. When the RINs are separated from the renewable fuel and sold independently, the RIN seller may use the revenue received for the RIN to discount the effective cost of the renewable fuel. In order to recover the cost of purchasing RINs, however, obligated parties are expected to increase the selling price of the petroleum products they produce. If fuel prices are fully flexible, markets are perfectly competitive, and we assume no changes to the price of renewable or petroleum based fuels, these two price impacts, the discounting of renewable fuels enabled by the sale of the RINs and the higher petroleum prices that result from the cost of purchasing RINs, are expected to offset each other, resulting in the RIN price having no net impact across the entire fuel pool.

We note, however, that higher RIN prices are expected to have an impact on the retail price of transportation fuels such as E85, E10, and diesel fuel based on their renewable content. In some cases high RIN prices are expected to decrease the retail price of the fuel, while in others they are expected to result in an increase in the retail price of the fuel. High RIN prices are expected to reduce the price of fuel blends that contain a higher percentage of renewable fuels, such as E85 or B20, while increasing the price of fuels that contain little or no renewable fuels.[5] An increase in D6 RIN prices, as seen in 2013, is expected to result in a significant decrease in the price of E85, a very small decrease in the price of E10, and an increase in the price of diesel fuel. This is because the RIN costs of a gallon of fuel (the price increase of the petroleum blendstock due to the RIN obligations) is proportional to the amount of petroleum blendstock contained in a fuel blend, while the RIN value (the effective price reduction of the renewable fuel content enabled by the sale of the RIN) is proportional to the renewable content of the blend. These price impacts are one of the primary ways the RFS program can incentivize the increased blending and consumption of

[3] Scarcity pricing occurs when the price of a good increases significantly due to concerns over a limited supply. In this context we use the term scarcity pricing to refer to a situation where the price of D6 RINs rises significantly beyond what would be expected when considering the price of ethanol and the consumer demand price for ethanol when sold as E85.

[4] In some cases the fuel blender and obligated party may be the same company.

[5] This is expected to be true in a competitive market, however many of these expected price reductions may not be realized for fuels such as E85 that at the current time generally face little competition at the wholesale and retail level. As the availability of these fuels increases we anticipate that a higher proportion of the expected price decrease will be realized by consumers.

renewable fuels in the United States. In blends such as E10, RIN prices are expected to have little overall impact as the RIN cost is approximately equal to the RIN value.

Finally, we examined available data to determine if the expected impacts of high RIN prices could be observed. We were able to observe these impacts in several areas, notably in price differences between petroleum-based fuels with and without RIN obligations and in lower wholesale and retail prices for fuel blends containing higher percentages of renewable fuels. RIN prices are not expected to have a significant impact on the wholesale or retail prices of E10, the most widely used transportation fuel in the United States, as the rise in the market price of the petroleum blendstock due to the RIN cost is offset by the lower effective price of the ethanol portion of the blend enabled by the value of the RIN. The higher market prices for petroleum fuels with RIN obligations relative to those without RIN obligations suggest that obligated parties are generally recovering their RIN costs in the price of the petroleum fuels they produce. Merchant refiners, who largely purchase separated RINs to meet their RFS obligations, should not therefore be disadvantaged by higher RIN prices, as they are recovering these costs in the sale price of their products. Were this not the case, merchant refiners could, and we expect would, avail themselves of other compliance strategies such as contractual arrangements and investing in fuel blending and distribution infrastructure, which are available to merchant refiners looking for alternative methods for meeting their RIN obligations.

Each of these conclusions, and the available data that EPA examined to arrive at these conclusions, is presented in further detail below. While the focus of this document is explaining the rise in RIN prices and resulting fuels marketplace impacts in 2013, we expect a similar set of issues and market forces will be at work in future years.

We note that this document examines available data through June 2014. EPA intends to continue to monitor available data and update the assessments contained in this document as time allows and data becomes available. EPA also welcomes feedback and input on our methodology and conclusions.

Background

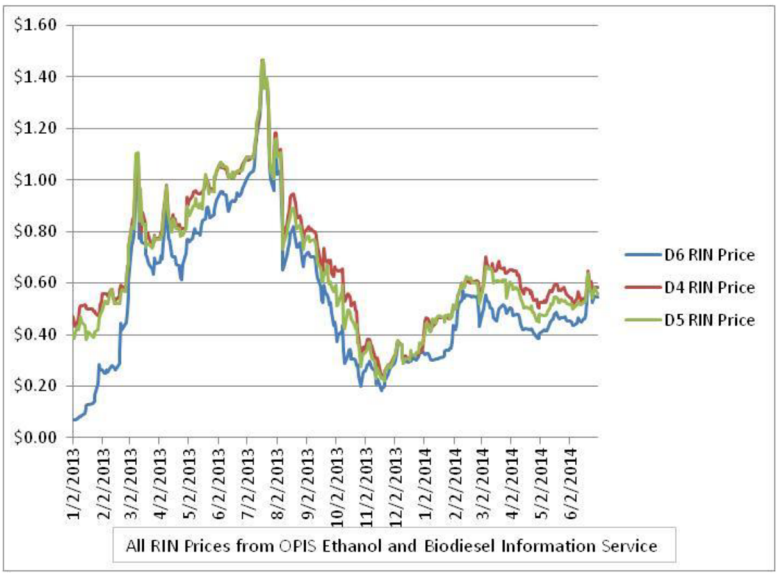
On March 26, 2010 EPA published changes to the RFS program regulations, as required by the Energy Independence and Security Act of 2007 (EISA), to ensure that transportation fuel sold in the United States contains volumes of renewable fuel that are either specified in the statute or set by EPA pursuant to specified waiver authorities. The EISA amendments increased the volume of renewable fuel required to be blended into transportation fuel to 36 billion gallons by 2022. As a part of the RFS regulations, EPA implemented a system for tracking the production and use of qualifying renewable fuel using Renewable Identification Numbers or RINs. These RINs are generated by renewable fuel producers or importers and are bought and sold "attached" to the renewable fuel until the fuel is purchased by an "obligated party" (a refiner or importer of gasoline or diesel fuel) or blended with a petroleum-based transportation fuel. At that point the RIN is "separated"

from the fuel and may thereafter be independently bought or sold until it is retired to meet an obligated party's renewable volume obligation or for some other reason.

By providing an opportunity for obligated parties to fulfill their obligations under the RFS program by purchasing RINs, the RIN market allows obligated parties the flexibility to choose whether or not to be directly involved in the blending of renewable fuels. Obligated parties may choose to acquire RINs by directly blending renewable fuels, by purchasing renewable fuel, separating the RINs, and selling the renewable fuel without RINs, or by purchasing separated RINs on the spot market or through other contractual arrangements. While most RINs are used for compliance in the year they are generated, up to 20% of an obligated party's renewable volume obligation (RVO) may be satisfied with RINs generated in the previous year. This allows excess RINs to function as an inventory in the RIN trading market and provides compliance flexibility to the obligated parties as excess (or "carry over") RINs can act as a buffer for obligated parties to protect themselves against unforeseen changes in the RIN market. Obligated parties may also defer their RFS obligation, in whole or in part, to the following year, provided that the RIN obligation is satisfied together with the party's next year's RVO.

In 2013 the price for Renewable Fuel RINs (D6) increased substantially, from an average of a few cents per RIN in previous years to over $1.00 per RIN in the summer of 2013 (see Figure 1 below). The swift run up in the RIN price led a variety of stakeholders to conduct analyses looking into the causes and impacts of the increase. This document presents EPA's assessment of the cause of the high RIN prices, the expected impacts on retail fuel prices of high RIN payments, and the impact of high RIN prices on obligated parties. Throughout, this document focuses on D6 RINs; references to RIN prices are to D6 RINs unless otherwise noted.

Figure 1
RIN Prices



RIN Market Overview

In attempting to describe and explain the many factors that affect RIN prices or the effect of RIN prices on fuel prices and market participants, it is helpful to begin with a look at the roles different RIN market participants play. RINs are generated by renewable fuel producers.[6] RINs may be generated any time after the fuel is produced but before the fuel leaves the custody of the renewable fuel producer. Each RIN is "attached" to a gallon of renewable fuel and must be sold with that gallon of renewable fuel for which it was generated.

After a gallon of renewable fuel is sold, it is generally blended with a petroleum based fuel to produce a transportation fuel such as E10, E85, or B5. When a gallon of renewable fuel with an attached RIN is purchased by an obligated party[7] or blended to create a

[6] Renewable fuel must be made from "renewable biomass" in accordance with a "pathway" determined by EPA to satisfy lifecycle greenhouse gas reduction requirements (or be grandfathered from such requirements) and be produced for use as transportation fuel, jet fuel or home heating oil. Pathways are a combination of feedstock, finished fuel type, and production process. For a list of currently approved pathways see 40 CFR 80.1426

[7] In the RFS program an obligated party is defined as any refiner that produces gasoline or diesel fuel in the 48 contiguous states or Hawaii, or any importer that imports gasoline or diesel fuel, into the 48 contiguous states or Hawaii

transportation fuel the owner of the fuel may separate the RIN from the renewable fuel. The RIN can then be used by the obligated party to demonstrate compliance with their RFS obligation, or it can be sold to another obligated party seeking RINs to fulfill their renewable volume obligation. Figure 2 presents a basic schematic of the RIN/renewable fuel market.

Figure 2
Product Transfers in the Renewable Fuel and RIN Market[8]

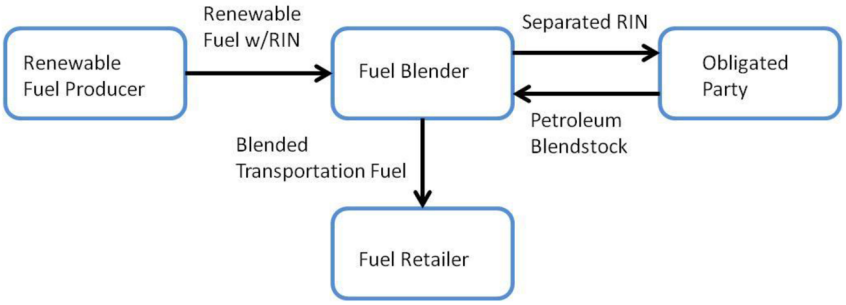


Figure 2 greatly simplifies the reality of a complex marketplace. For example, many obligated parties also own fuel blending operations, and others may purchase renewable fuel with an attached RIN, retain the RIN, and then sell the renewable fuel without the RIN. In practice several parties may take ownership of a renewable fuel before it is blended with a petroleum blendstock to produce a transportation fuel. Similarly separated RINs may be sold to brokers or aggregators before being sold to obligated parties. Where there are additional parties participating in the marketplace not shown in the graphic above, the commodity price received by one of the depicted parties will not be equal to the purchase price paid by the party who ultimately receives the commodity as the intermediate parties will require a fee for their services. We do not expect these fees to be significant, as the RIN and transportation fuel marketplaces are generally competitive.

There are also cases where a single company may be active in multiple areas of the transportation fuel market place. Examples include an ethanol production facility that blends finished transportation fuel, or a refiner who owns fuel blending terminals. In these cases certain transactions may take place within a single company rather than between two companies. The same fundamental transactions, however, still take place, whether they are internal to one company or external and involve different entities.

[8] In the graphics in this document we have depicted the renewable fuel producer, fuel blender, obligated party, and fuel retailer as independent entities. In reality two or more of these functions may be conducted by the same company. Traditionally many obligated parties have also functioned as fuel blenders, and increasingly renewable fuel producers are also producing and marketing renewable fuel blends.

Factors Affecting the RIN Price

EPA designed the RIN program with the intention of providing a market-based compliance mechanism that would cause minimal disruption in the transportation fuel marketplace, while also providing EPA with the necessary assurance that the mandated volumes of renewable fuel would be used in the transportation sector. EPA sought to provide flexibility to refiners, importers, and other producers of petroleum-based transportation fuel by allowing obligated parties to purchase RINs and rely on the existing renewable fuel production, distribution, and blending marketplace rather than requiring each obligated party to directly blend a quantity of renewable fuel equal to their renewable volume obligation. If the RIN market is functioning efficiently the RIN price should be approximately equal to the difference between a renewable fuel's supply price and its demand price (the price the market is willing to pay for the renewable fuel as a transportation fuel). The RIN price provides the incentive the renewable fuel producer needs to continue to produce renewable fuel up to the mandated volume even if the demand price for the fuel would not otherwise cover the cost of production of the renewable fuel.

With this in mind, EPA examined available price data to determine if changes in the supply and demand price for renewable fuels explained the rising and variable D6 RIN prices observed in 2013. Determining a supply price was straightforward: EPA used ethanol[9] price data reported weekly by USDA.[10]

Determining the demand price for ethanol, however, is more complicated. Ethanol, in its unblended form, cannot be used as a transportation fuel by vehicles in the United States. It must be blended with gasoline to produce transportation fuels such as E10 (containing 10% ethanol) or higher level blends such as E85 (containing between 51% and 83% ethanol with a national average ethanol content of 74% as reported by the Energy Information Administration (EIA)).

We posit that the demand price for ethanol in a blended transportation fuel varies significantly depending on the ethanol blend level. The vast majority of ethanol sold as transportation fuel in the United States is sold as E10. When ethanol is sold in an E10 blend we believe that the demand price is approximately equal to the price of the gasoline fuel into which it is blended on a volumetric basis, despite the fact that ethanol contains approximately 33% less energy per gallon than gasoline.

There are several reasons we believe this to be the case. Due to the relatively low level of ethanol in E10 the fuel economy reduction of E10 as compared to E0 (gasoline without ethanol) is fairly small (approximately 3%) and not noticeable by most consumers. Customers therefore generally do not seek price discounts for E10 v. E0. Furthermore, for

[9] Throughout this document all references to ethanol are to denatured ethanol

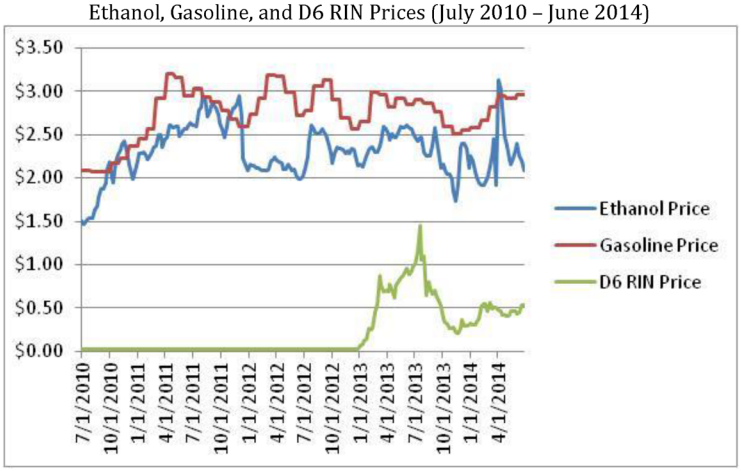
[10] Data recorded by Agricultural Marketing Resource Center. These prices are for ethanol with attached RINs. Accessed online April 10, 2014 <http://www.agmrc.org/renewable_energy/ethanol/midwest-ethanol-cash-prices-basis-data-and-charts-for-selected-states/>

the relatively few consumers who are aware of the slightly lower energy content (and therefore lower fuel economy) of E10 as compared to E0, options to purchase E0 are very limited as virtually all gasoline sold in the United States now contains 10% ethanol. Where E0 is available, it is generally priced at a significant premium relative to E10, thus negating any potential value it may have offered due to its higher energy content. For a further discussion of the pricing of ethanol as E10 see the 2012 Notice of Decision Regarding Requests for a Waiver of the Renewable Fuel Standard.[11]

If the demand price for ethanol as transportation fuel when blended as E10 is approximately equal to the price of gasoline on a volumetric basis, rather than an energy-equivalent basis, we would expect D6 RIN prices to be very low whenever the ethanol price is below the gasoline price. This is because fuel blenders can generate profit by purchasing ethanol for a lower price than gasoline and sell the blended E10 at a price approximately equal to that of the gasoline blendstock on a per gallon basis despite the lower energy content of the fuel. No RIN value is necessary for the blending of ethanol to be profitable under these conditions. This was the case throughout the history of the RFS program until the early months of 2013. As shown in the graph below, from July 2010, the effective date of the updated RFS regulations, through the end of 2012 ethanol was generally priced below gasoline *on a volumetric basis*, and D6 RIN prices were only a few cents, likely attributable to RIN transaction costs. In 2013 the price of ethanol generally remained below the price of gasoline on a volumetric basis, yet the price of D6 RINs increased substantially. We believe a significant factor in this change in RIN price was a saturation of the E10 pool requiring that any additional volumes of ethanol be blended as E85.

[11] FRL-9754-4

Figure 3
Ethanol, Gasoline, and D6 RIN Prices (July 2010 – June 2014)



Note: The ethanol blenders tax credit expired on December 31, 2011, likely resulting in the decline in ethanol price in January 2012. The price spike in March/April 2014 was primarily the result of extremely cold winter temperatures leading to rail congestion[12]

When ethanol is sold as an E85 blend available information suggests that the ethanol has a significantly different consumer demand price. E85 blends contain significantly less energy per gallon than E10 (approximately 22% less energy per gallon assuming E85 contains 74% ethanol). This lower energy content results in a decrease in fuel economy of approximately 22% when owners of flexible fuel vehicles (FFVs) operate their vehicles on E85 rather than E10. Not only is the decrease in fuel economy more noticeable to fuel customers, but the fuel customers also have the ability to choose between purchasing E85 or E10, as E10 is available everywhere that E85 is. For E85 to appeal to most customers, therefore, it would need to be priced in a manner that accounts for the fuel economy penalty, as well as any "inconvenience factor" associated with its lack of availability relative to E10 and the need to refuel more frequently.

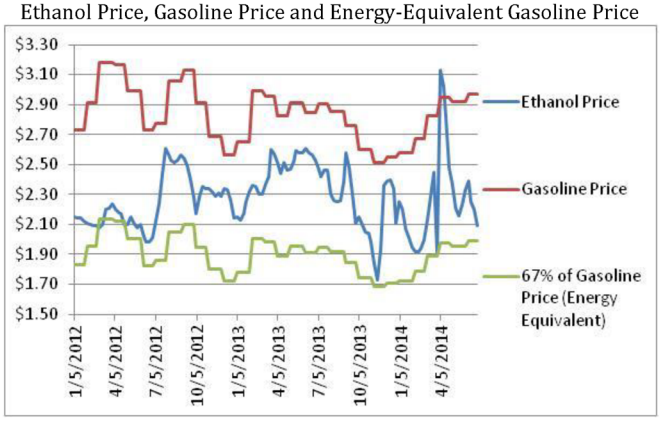
We argue that the more noticeable decrease in fuel economy and the greater availability of alternative fuel choices has a significant impact on consumer decisions regarding purchases of E85. While some FFV owners, primarily motivated by factors other than minimizing fuel costs[13], may purchase E85 at prices above energy parity, the majority of

[12] For further information on this issue see "Rail congestion, cold weather raise ethanol spot prices." *Today in Energy*. U.S. Energy Information Administration, April 3, 2014. Web. September 25, 2014 <http://www.eia.gov/todayinenergy/detail.cfm?id=15691>.

[13] Consumers may purchase E85 when priced above energy parity for reasons such as supporting the rural economy, a desire to buy a domestically sourced fuel, E85's perceived environmental attributes, or government fleet mandates. Alternatively some customers may avoid purchasing E85 even when it is

potential E85 customers will likely only purchase E85 if it is priced at a per gallon discount equal to or greater than the difference in energy content between E85 and E10.[14] If this is the case, the demand price for ethanol as a transportation fuel in an E85 blend is proportional to gasoline on an energy-equivalent, rather than a volumetric basis. This means that we would expect the true demand price for ethanol blended as E85 to be approximately 67% of the price of gasoline.[15] We would further expect that in a competitive market the D6 RIN price would be approximately equal to the difference between the price of ethanol relative to the price of gasoline on a volumetric basis (or near zero if ethanol were cheaper) when ethanol was primarily sold as E10, as it was until the end of 2012, and approximately equal to the difference on an energy-equivalent basis (67% of the price of gasoline) when the E10 market is effectively saturated and additional ethanol must be blended as E85, as it was in 2013. The prices of ethanol, gasoline, and an ethanol-equivalent gallon of gasoline (67% of a gallon) for 2012 and 2013 are shown below (Figure 4), followed by a graph that compares the difference between these prices and the observed D6 RIN price in 2012 and 2013 (Figure 5).

Figure 4
Ethanol Price, Gasoline Price and Energy-Equivalent Gasoline Price

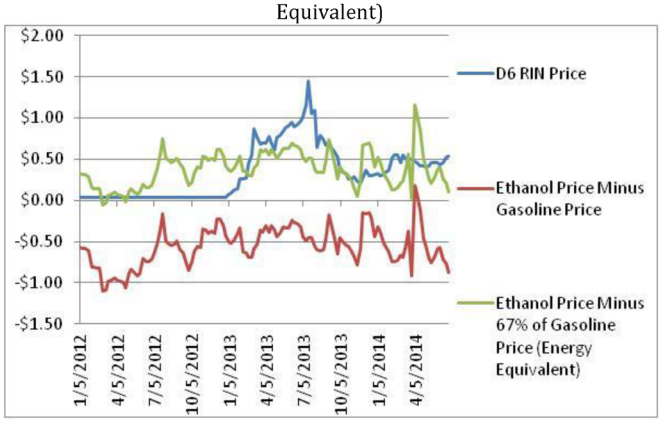


available and priced below energy parity due to concerns about fuel quality, a desire to avoid more frequent refueling, or a lack of knowledge that the fuel is compatible with their vehicle.

[14] Informed customer decisions are often complicated by a lack of information on the precise ethanol content of E85. E85 may contain anywhere from 51% to 83% ethanol. Uncertainty regarding the ethanol content of E85 may hinder a customers ability to effectively choose the lower cost fuel on an energy-equivalent basis.

[15] The energy content of ethanol (77,000 BTU/gallon) is approximately 67% of the energy content of gasoline or E0 (115,000 BTU/gallon).

Figure 5
D6 RIN Price and Difference Between Ethanol and Gasoline Price (Volumetric and Energy-Equivalent)



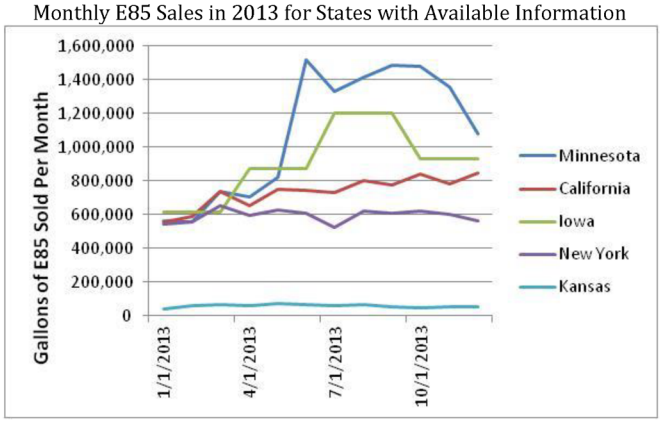
For the first time in 2013, the portion of obligated parties' total renewable volume obligations that could be satisfied with D6 RINs (the total volume obligation for non-advanced biofuels) exceeded the quantity of RINs that could be obtained by blending ethanol with gasoline to create E10. Because the amount of ethanol that could be blended as E10 was effectively capped, obligated parties looked to alternative sources of RINs, such as increased blending of ethanol as E85, the blending of additional non-ethanol biofuels, or the use of carry over RINs (RINs generated in 2012 available to satisfy 2013 obligations). In the ethanol market, we argue that the customer demand price shifted from a price based in part on gasoline on a volumetric basis (as it had been when increased blending of ethanol as E10 had represented the marginal gallon of ethanol), to one based in part on gasoline on an energy-equivalent basis, as increased ethanol blending of ethanol as E85 now represented the marginal gallon of ethanol. Figure 5 illustrates this shift. Throughout the vast majority of the time from January 2012 through June 2014 ethanol was cheaper than gasoline on a volumetric basis. Prior to reaching the E10 blendwall in 2013 the demand price for ethanol was primarily based on that of gasoline on a volumetric basis and D6 RINs were only a few cents, effectively representing transaction costs. After reaching the blendwall the demand price for ethanol shifts to being based primarily on the price of gasoline on an energy-equivalent basis. Because ethanol was more expensive than gasoline on an energy-equivalent basis from January 2013 through June 2014 the D6 RIN prices help offset the difference between the supply price of ethanol and the new demand price when the marginal gallon of ethanol is sold as E85.

This higher D6 RIN value also provided an increased opportunity for the increased blending of non-ethanol fuels, which may not have been profitable to blend into transportation fuel with low D6 RIN prices. In each of these cases, increased blending of ethanol as E85 and increased use of non-ethanol biofuels, the supply price exceeded the

demand price for these renewable fuels when used as a transportation fuel. As a result, RIN prices increased in 2013 as shown in Figure 1. The increasing D6 RIN price provided an incentive not only for increased blending of ethanol as E85, but also for the increased production and import of non-ethanol fuels such as biodiesel and for a draw-down in the bank of carry over RINs.

During the period of high RIN prices in the middle of 2013 some parts of the United States saw growth in E85 sales. This growth was most notable in states, such as Minnesota and Iowa, where the RIN value was most likely to be passed on to the consumer due to competition at both the wholesale and retail level in the E85 market.[16] However, consumption of E85 remained limited despite the high RIN prices due to a variety of factors including a lack of infrastructure for the blending, sale, and consumption of E85, and the lack of competitive markets leading to limited RIN value pass through to consumers in many markets.

Figure 6
Monthly E85 Sales in 2013 for States with Available Information



High D6 RIN prices had an even more significant impact on the production and consumption of non-ethanol biofuels such as biodiesel and renewable diesel, which did not face the same infrastructure challenges as ethanol blended as E85. Generation of D6 RINs for biodiesel and renewable diesel increased from approximately 6 million and 1 million in 2011 and 2012 respectively to over 250 million in 2013.[17] Generation of D4 (biomass-based diesel) RINs were also at the highest levels achieved under the RFS program. The increased availability of these fuels, combined with the availability of carry over RINs from excess production in 2012 helped to moderate the price of D6 RINs in 2013 despite the

[16] According to data from DOE's Alternative Fuels Data Center approximately 20% of all E85 stations in the United States in 2013 were located in Minnesota or Iowa
[17] All RIN production numbers from EMTS

limited ability of RIN prices or volume mandates to increase the consumption of ethanol as E85.

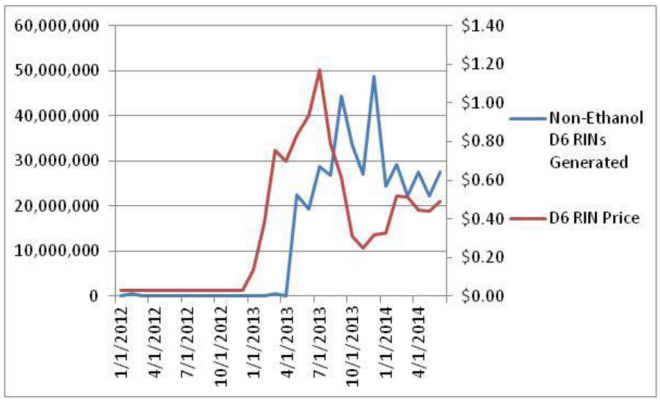
On the basis of the data available to EPA, we believe much of the increase in 2013 D6 RIN can be explained by the arrival of the E10 blendwall in 2013 and the resulting change in demand price for ethanol. These factors alone, however, do not provide a complete explanation of the observed D6 RIN prices. As shown in Figure 5, from May 2013 through August 2013, spot D6 RIN prices were substantially higher than would have been expected based solely on the prices of ethanol and gasoline. This may have been due to a variety of factors, including: limited blending and retail infrastructure for E85, limited ability for RIN prices to affect the retail price of E85, the RIN price needed to incentivize increasing the production or import of non-ethanol fuels, and uncertainty about the final RFS standards for 2013 and 2014. It may also be the case that the reported prices for D6 RINs reflect the price of a relatively small number of RINs traded on the spot market rather than the D6 RINs purchased through long term contracts and are therefore more volatile and not necessarily reflective of the average D6 RIN price. Regardless, these elevated D6 RIN prices increased the incentive for the production, import, and consumption of non-ethanol fuels, notably biodiesel produced from grandfathered facilities,[18] which were eligible to generate D6 RINs and could now compete in the domestic fuels market as a result of their significantly increased RIN value. In other words, renewable fuels that were uneconomic to produce or import to satisfy the D6 RIN obligations when RIN prices were only a few cents became economic to produce or import with substantially increased D6 RIN prices.

It is highly speculative and difficult to predict the future price of D6 RINs, as they are influenced by multiple factors, including the supply and demand prices for ethanol, the price of petroleum, the cost of production of non-ethanol renewable fuels, consumer behavior in the E85 market, and availability of alternative compliance mechanisms. However, given the fact that the required total renewable fuel volume will likely exceed the volume of ethanol that can be blended as E10 in the future, we would not expect D6 RIN prices to return to the prices seen from 2010 to 2012.[19]

[18] Grandfathered facilities are those that commenced construction on or before December 17, 2007, or any ethanol plant fired by natural gas, biomass, or a combination thereof that commenced construction before December 31, 2009. These facilities are exempt from the 20% GHG reduction requirement for the generation of D6 RINs, however they still must use a feedstock that meets the renewable biomass definition, be intended for use as transportation fuel or other qualifying uses, and meet all other reporting and recordkeeping requirements.

[19] RIN prices could return to historic low levels of a few cents if the price of ethanol or other renewable fuels fell sufficiently below the cost of gasoline on an energy equivalent basis

Figure 7
Generation of Non-Ethanol D6 RINs and D6 RIN Price



*RIN Prices from OPIS Ethanol and Biodiesel Information Services

RIN Price Impact on Transportation Fuel Prices

The high RIN prices observed in 2013 prompted questions not only regarding the cause of the increase, but also about the impact the RIN prices would have on the retail price of transportation fuel. Some have suggested that higher RIN prices necessarily lead to higher retail prices for all transportation fuels.[20] Our analysis, however, indicates that this is not likely to be the case. In short, this is due to the fact that, rather than being an additional cost, RINs can be viewed as transfer payments from obligated parties to renewable fuel blenders to incentivize the blending of renewable fuels and the sale of fuel blends with higher renewable content. These payments, while having no net impact on the overall cost of transportation fuel, can reduce the price of fuels with high renewable content, such as E85, at the expense of fuels such as diesel that generally contain a small percentage of renewable fuel. This can ultimately increase the demand for renewable fuels by giving the fuel blenders a greater incentive to increase the renewable content of the fuel blends they sell.

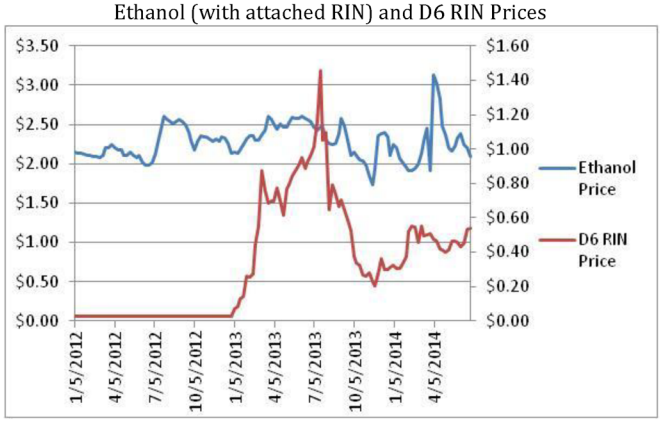
If the cost of producing ethanol and gasoline blendstocks (or biodiesel and diesel fuel) remains unchanged, then the overall cost of the blended fuels should not be impacted by RIN prices.[21] This does not mean that there is no cost to increasing the volume of renewable fuels required to be blended into the transportation fuel pool. If renewable fuels cost more on an energy-equivalent basis than the petroleum fuels they displace there is a

[20] For example see "Gasoline Price Inflated by Ethanol in Oil Boom: Energy Markets" by Mario Parker, published by Bloomberg on March 21, 2013. Available online < http://www.bloomberg.com/news/2013-03-21/gasoline-price-inflated-by-ethanol-in-oil-boom-energy-markets.html>

[21] As stated in the previous paragraph, however, varying RIN prices are expected to impact the relative prices of different fuel types such as E85, E10, E0, B20, B5, etc.

cost to using these renewable fuels; and the higher the required volume of these fuels, the higher the cost will be. As can be seen in examining the available data, however, the sharp rise in D6 RIN prices did not have a measurable impact on the prices of ethanol with attached RINs (see Figure 8). Renewable fuel blenders acquire RINs by purchasing renewable fuels with attached RINs.[22] They sell these RINs to obligated parties, who look to recover the cost of these RINs in the price of the blendstocks they sell to the fuel blenders. Higher blendstock prices are in turn offset by the RIN value captured by blenders when they blend renewable fuels. We expect that higher RIN prices may increase the magnitude of these payments between obligated parties and renewable fuel blenders, as well as the relative pricing of fuel blends containing higher volumes of renewable fuels versus those containing little or no renewable fuel (see Figures 9 and 10 below), but that the net impact of these transfers on the cost of transportation fuel would be minimal.

Figure 8
Ethanol (with attached RIN) and D6 RIN Prices



To illustrate this we examined the expected price of fuel supplied to the retailer for both E10 and E85. We did this first assuming a relatively low average RIN price and then again using the average RIN prices in 2013. The prices used for this example are shown in Table 1 below. The RIN obligation percentages are based on the 2013 volume requirements and standards. We note that because the standards are nested, the D6 RIN obligation percentage is equal to the total renewable fuel percentage standard minus the advanced biofuel percentage standard. Similarly, the D5 RIN obligation percentage is equal to the advanced biofuel percentage standard minus the biomass-based diesel percentage standard. For this example we have ignored the very small cellulosic biofuel requirement.

[22] As noted previously, renewable fuels with attached RINs can be purchased directly by obligated parties, and many obligated parties also blend renewable fuels to produce transportation fuel.

The total RIN cost is calculated by summing the product of the RIN obligation percentages by the corresponding RIN price for each of the RIN types.[23] The structure of the RFS program is such that every gallon of gasoline or diesel fuel produced or imported in the United States has an equal RIN obligation, including cellulosic, biomass-based diesel, advanced, and total renewable RINs. This means that the RIN cost for a gallon of gasoline is impacted by the price of the biomass-based diesel RIN, even though biodiesel cannot be blended into gasoline. Our examples reflect this structure, with identical RIN costs for gasoline and diesel that vary with different RIN prices. For these examples we have ignored transportation, overhead, and profit-taking[24] to simplify our analysis. While these are all factors that will impact the cost paid by retailers for blended fuels, we would not expect them to vary with RIN prices and have therefore not explicitly considered them in our example.

Table 1
Illustrative Commodity Prices for Exploring RIN Price Impacts on Retail Fuel Prices

	Low RIN Prices	High RIN Prices (2013 Average for RIN Prices)
Ethanol (with attached RIN)[25]	$2.25/gallon	$2.25/gallon
Gasoline blendstock (without RIN costs)	$2.75/gallon	$2.75/gallon
Biodiesel (with attached RIN)	$4.00/gallon	$4.00/gallon
Diesel blendstock (without RIN costs)	$3.25/gallon	$3.25/gallon
D6 RIN Price	$0.05	$0.60
D4 RIN Price	$0.50	$0.73
D5 RIN Price	$0.25	$0.71
D6 RIN Obligation	8.12%	8.12%
D4 RIN Obligation	1.13%	1.13%
D5 RIN Obligation	0.49%	0.49%
Total RIN Cost per gallon(All RIN obligations)	$0.01	$0.06

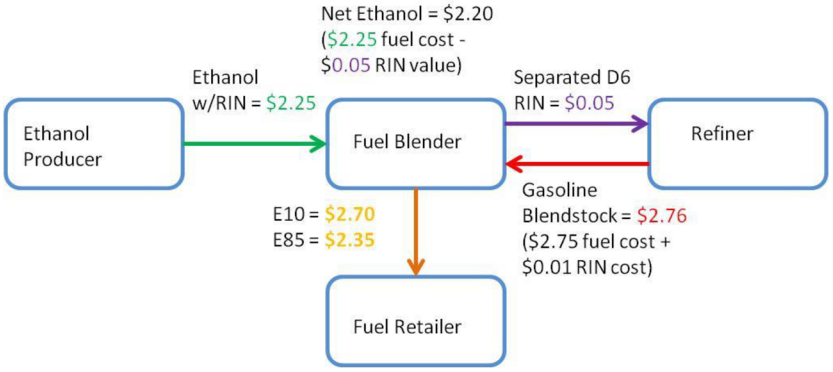
Using these assumptions for commodity prices, and based on our schematic of the RIN and fuel market shown in Figure 2 above, we can follow each of the fuel types through the RIN and fuel market to estimate the impacts on the price paid by retailers for both E10 and E85.

For the low RIN price scenario, we begin with the purchase of ethanol by the fuel blender from the renewable fuel producer. In this transaction the fuel blender receives one gallon

[23] Per Gallon RIN Cost = D6 RIN Obligation * D6 RIN Price + D5 RIN Obligation * D5 RIN Price + D4 RIN Obligation * D4 RIN Price. This is the RFS "compliance cost" for each gallon of gasoline and diesel produced or imported by an obligated party.
[24] EPA has examined some data that suggests increased profit taking during times of high RIN prices in the E85 market, but believe this will decrease as competition in the E85 marketplace increases.
[25] As shown in Figure 8, data from 2013 strongly suggests that the price of ethanol with an attached RIN is not a function of the RIN price

of ethanol and the corresponding D6 RIN from an ethanol fuel producer for $2.25. After receiving the ethanol from the ethanol producer the fuel blender separates the D6 RIN and sells it to an obligated party for $0.05. The net purchase price for the ethanol without the RIN is therefore $2.20. The fuel blender next purchases gasoline blendstock from a refiner. The price the refiner would charge for one gallon of gasoline blendstock in the absence of the RFS program in this example is assumed to be $2.75 per gallon. Anticipating the need to purchase RINs to satisfy the RIN obligation associated with selling the gallon of gasoline blendstock, the refiner instead charges the fuel blender $2.76 per gallon ($2.75 for the cost of the gasoline blendstock and $0.01 to cover the per gallon cost of the RIN obligations). The fuel blender has effectively paid $2.20 per gallon of ethanol ($2.25 per gallon with attached RIN - $0.05 cost recovered in the sale of the RIN) and $2.76 per gallon of gasoline blendstock ($2.75 for the blendstock + $0.01 RIN recovery cost). The cost of producing blended fuels can be calculated by taking the average of these two fuel component costs weighted by the proportion of each component in the finished fuel blend.[26] The resulting blended fuel costs are $2.70 per gallon for E10 and $2.35 per gallon of E85. The prices and flows of the various commodities are shown in Figure 9 below.

Figure 9
Impact of Low RIN Prices on the Cost of Gasoline to Retailers

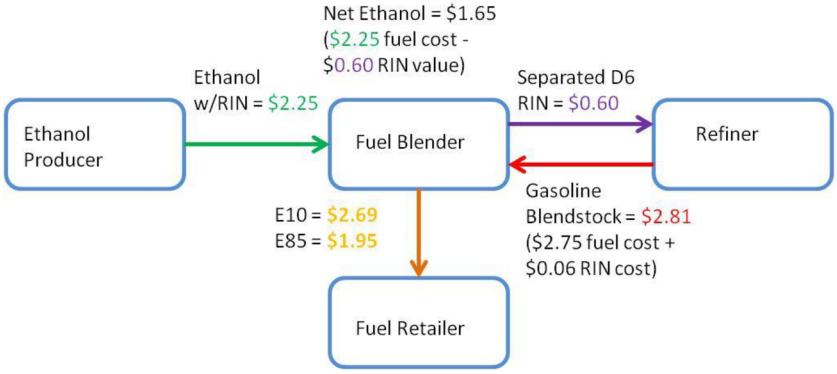


A similar scenario can be examined with high RIN prices, such as those observed in 2013. For this scenario, we begin in the same place, with the purchase of ethanol by the fuel blender from the renewable fuel producer. As in the previous scenario, the fuel blender receives one gallon of ethanol and the corresponding D6 RIN from an ethanol fuel producer for $2.25. In this case, however, after being separated from the gallon of ethanol the RIN is sold to an obligated party for $0.60. The net purchase price for the ethanol without the RIN is therefore $1.65 rather than $2.20 in the previous scenario. In response to the higher RIN

[26] For this example we have assumed E10 contains 10% ethanol and 90% gasoline blendstock and E85 contains 74% ethanol and 26% gasoline blendstock. The equations to calculate the cost are therefore E10 = 0.1*[net ethanol cost] + 0.9*[net gasoline blendstock cost] and E85 = 0.74*[net ethanol cost] + 0.26*[net gasoline blendstock cost].

prices, the refiner must charge more for each gallon of gasoline blendstock sold to cover the cost of purchasing RINs to fulfill their RVO. The refiner now charges the fuel blender $2.81 per gallon of gasoline blendstock ($2.75 for the cost of the gasoline blendstock and $0.06 to cover the cost of the RIN obligations). In this high RIN price scenario, the fuel blender has effectively paid $1.65 per gallon of ethanol ($2.25 per gallon with attached RIN - $0.60 cost recovered in the sale of the RIN) and $2.81 per gallon of gasoline blendstock ($2.75 for the blendstock + $0.06 RIN recovery cost). The resulting blended fuel costs are $2.69 per gallon for E10 and $1.95 per gallon of E85. The prices and flows of the various commodities are shown in Figure 10 below.

Figure 10
Impact of High RIN Prices on the Cost of Gasoline to Retailers

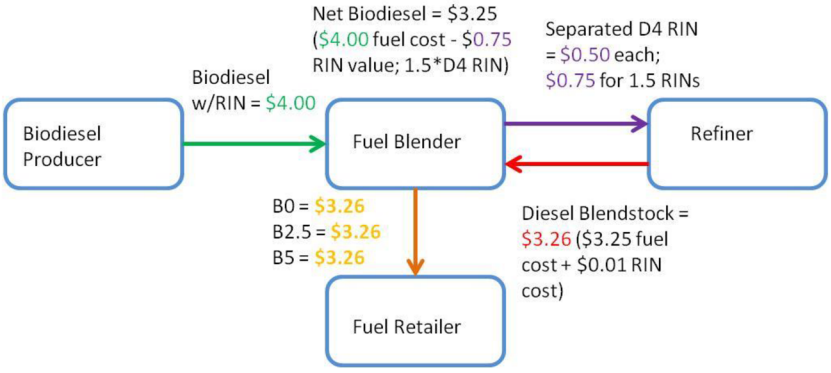


As these two scenarios demonstrate, rising RIN prices alone are not expected to increase the price of transportation fuel to retail station owners, however they have a significant impact on the relative prices of fuels with a relatively high renewable content (E85) as compared to those with a relatively low renewable content (E10). As the cost of acquiring RINs rises, refiners and other obligated parties are expected to respond to this cost by increasing the price of the gasoline blendstock they are selling to recover their increasing RIN costs. While this does increase the market price for the gasoline blendstock, this increase is generally offset by the lower net price paid for the ethanol with which the gasoline blendstock is blended.

The same market dynamics are at work in the diesel fuel marketplace. When considering the impact of RIN prices on cost of fuel to the retailer, we begin with the purchase of biodiesel by the fuel blender from the renewable fuel producer. The fuel blender receives one gallon of biodiesel and 1.5 D4 RINs from a biodiesel producer for $4.00. Each gallon of biodiesel generates 1.5 RINs due to the higher energy content of biodiesel relative to ethanol. After being separated from the gallon of biodiesel, the RINs are sold to an obligated party for $0.50 each (the blender receives the total RIN value associated with a gallon of biodiesel; $0.75 in the low RIN price scenario). The net purchase price for the

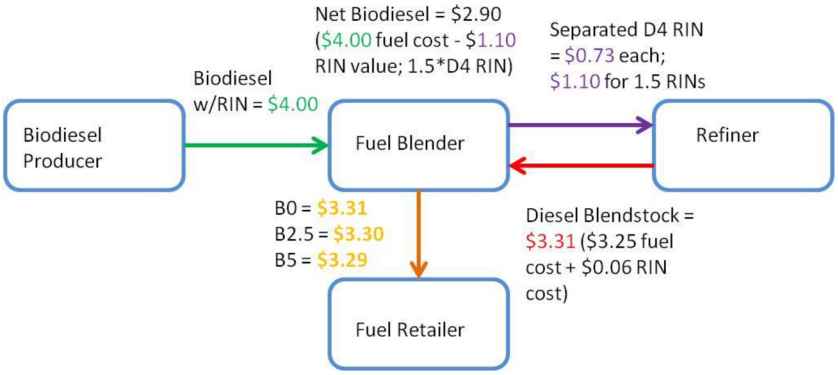
biodiesel without the RIN is therefore $3.25. For the purposes of this example we are not considering the impact of any blenders tax credit on the cost of biodiesel blends to retail stations. To cover the anticipated cost of their RIN obligation, the refiner charges the fuel blender $3.26 per gallon of diesel blendstock ($3.25 for the cost of the diesel blendstock and $0.01 to cover the cost of the RIN obligations). In this scenario, the fuel blender has effectively paid $3.25 per gallon of biodiesel ($4.00 per gallon with attached RIN - $0.75 cost recovered in the sale of the RINs) and $3.26 per gallon of diesel blendstock ($3.25 for the blendstock + $0.01 RIN recovery cost). The resulting blended fuel costs are an identical $3.26 per gallon for B0, B5 and B2.5 (the average blend rate if every gallon of diesel fuel sold contained biodiesel). The prices and flows of the various commodities are shown in Figure 11 below.

Figure 11
Impact of Low RIN Prices on the Cost of Diesel to Retailers



For the high RIN price scenario, the cost of the biodiesel with attached RINs to the fuel blender is the same $4.00 per gallon. The net purchase price for the biodiesel without the RINs is now reduced to $2.90 per gallon ($4.00 per gallon of biodiesel – 1.5 RINs * $0.73 per RIN). In response to the higher RIN prices, the refiner must charge an additional $0.06 for each gallon of diesel blendstock sold, resulting in a per gallon price of $3.31 per gallon for diesel blendstock. In this high RIN price scenario, the fuel blender has effectively paid $2.90 per gallon of biodiesel ($4.00 per gallon with attached RIN - $1.10 cost recovered in the sale of the RINs) and $3.31 per gallon of diesel blendstock ($3.25 for the blendstock + $0.06 RIN recovery cost). The resulting blended fuel costs are $3.31 per gallon for B0, $3.30 per gallon of B2.5, and $3.29 per gallon of B5. The prices and flows of the various commodities are shown in Figure 12 below.

Figure 12
Impact of High RIN Prices on the Cost of Diesel to Retailers



When comparing the impact of high versus low RIN prices on the cost of gasoline and diesel fuel blends to retailers we note two key differences. The first is that the price of gasoline and ethanol fuel blends are much more sensitive to high RIN prices than the price of diesel and biodiesel fuel blends (see Table 2 below). This is due to the fact that the renewable content of gasoline is generally much higher than for diesel fuel (almost all gasoline sold in the United States contains 10% ethanol, with limited availability of blends containing up to 85% ethanol; biodiesel is generally sold at blends containing 5% biodiesel or less, with few blends offered that contain more than 20% biodiesel).

Table 2
Impact of High RIN Prices on Retail Fuel Prices

	No RIN Price (No RFS)	Low RIN Prices	High RIN Prices
E0	$2.75	$2.76	$2.81
E10	$2.70	$2.70	$2.69
E85	$2.38	$2.35	$1.95
B0	$3.25	$3.26	$3.31
B2.5	$3.27	$3.26	$3.30
B5	$3.29	$3.26	$3.29

The second difference that can be observed is that increasing D6 RIN prices are expected to cause a slight decrease in gasoline prices and an increase in diesel prices. In the example above, which is designed to be reflective of a perfectly competitive market, any cost decreases that result from lower prices of gasoline-ethanol blends are offset by cost increases resulting from higher diesel fuel prices. The per gallon pricing changes for diesel

fuel are high relative to the pricing changes in E10 and low relative to the pricing changes in E85 primarily due to the relative renewable fuel content of these three fuel blends.

While not shown in the examples above, increasing D4 RIN price while holding the D6 RIN price constant would be expected to result in a slight increase in blended gasoline prices and a decrease in diesel prices. This is a result of the structure of the RFS program. Both gasoline and diesel blendstocks are subject to the same renewable volume obligations, and therefore the same costs associated with acquiring the necessary RINs. As shown in Table 1, this cost is $0.01 per gallon under the low D6 RIN price scenario and $0.06 per gallon under the high D6 RIN price scenario. In the scenarios presented above, the high D6 RIN prices can be used to reduce the net purchase price of fuels that generate D6 RINs, which in the majority of cases is corn ethanol. Gasoline-ethanol blends, such as E10 and E85, benefit from the lower net ethanol costs enabled by the higher D6 RIN prices, while diesel and biodiesel blends do not benefit as ethanol cannot be added to these fuels. The reverse scenario would also be true. If D4 RIN prices increased while D6 RIN prices were relatively unchanged the RIN cost for producing petroleum-based gasoline and diesel blendstocks would increase by the same amount. This would be expected to decrease the price of biodiesel blends (as the D4 RIN price reduced the net price of biodiesel) and cause slight increases in the price of gasoline-ethanol blends (which cannot be blended with biodiesel and therefore experience only a RIN cost). The magnitude of this impact, however, would likely be smaller as the D4 RVO is significantly lower than the D6 RVO.

Finally, we note that the price for unblended gasoline and diesel fuel increases in both the high and low RIN price scenarios as compared to a scenario where there are no RIN prices (no RFS). For E10, the most common fuel type sold for use in gasoline vehicles, this cost increase is offset by the effective cost reduction in the price of ethanol, resulting in little or no net change to the price of E10. For diesel-biodiesel fuel blends, however, this is not the case. The lowest price diesel fuel across the three scenarios is for unblended diesel in the no RIN price case. While it is true that in low and high RIN cases biodiesel blends are the same price as, or cheaper than unblended diesel fuel all of these products are more expensive than unblended diesel in the scenario where there is no RIN price.

Observing RIN Price Impacts in the Marketplace

After considering these simplified examples of how increasing RIN prices might impact the price of blended fuel to retailers, EPA examined available price information to determine if the expected price impacts (higher costs for petroleum blendstocks and lower net costs for renewable fuels) could be observed in the data. Due to the many independent factors that impact the cost of transportation fuels, this is not a straight-forward exercise. For example, it is not enough simply to observe the retail price of transportation fuel as the RIN prices fluctuate. If changes in RIN prices corresponded with changes in the price of crude oil (the primary cost of producing gasoline blendstocks), simply observing the relationship between RIN prices and retail fuel prices may give the false impression that increasing RIN prices have a direct impact on the retail pricing of blended fuels. Conversely, decreasing crude oil prices might mask the impact that changing RIN prices have on the price of gasoline blendstocks at the wholesale level or the retail price of blended fuels.

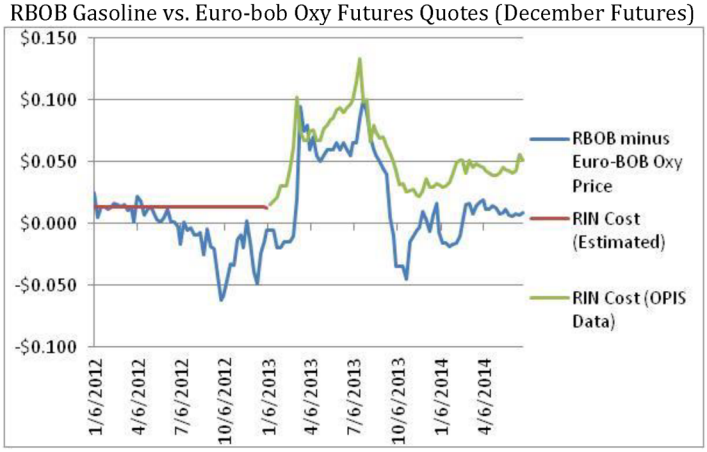
If the market is reacting to changes in RIN prices in the way that the scenarios presented in the previous section suggest, there are two places we expect we would be able to observe the impacts of the changing RIN prices in the market. The first is in the wholesale pricing of similar types of fuel with and without a RIN obligation. The scenarios presented above suggest that if RIN prices increase, obligated parties will respond by increasing the price they charge for petroleum based fuels to recover the cost of purchasing RINs to satisfy the RVO associated with the sale of these fuels. We would not, however, expect to see an increase in the price of similar fuels that are not subject to a RIN obligation. If we observed a sustained price delta between similar types of fuels with and without a RIN obligation, and if this price delta was approximately equal to the RIN cost associated with producing a gallon of petroleum based transportation fuel, it would provide support for our understanding that obligated parties are able to increase the cost of their petroleum blendstocks in order to recover the cost of their RIN obligations.

In the current market there exist several pairs of similar types of fuels wherein one of the pair carries a RIN obligation while the other does not. This allows us to examine the impact of RIN prices on the wholesale price of petroleum fuels. One such pair of fuels consists of gasoline produced for the domestic market (which is subject to an RVO) and gasoline sold for export to the European market (which carries no RIN obligation). Two other pairs are diesel based: diesel fuel is very similar to jet fuel and heating oil sold in the United States, but diesel fuel produced or imported into the U.S. has a RIN obligation while heating oil and jet fuel do not. EPA examined available pricing data for these three pairs of fuels (gasoline sold in the domestic v. foreign markets, diesel v. jet fuel, and diesel v. heating oil). Figure 13 shows the future quotes for RBOB Gasoline vs. Euro-bob Oxy for the December futures[27] (the price difference between gasoline grades sold for the United States and European markets) and the RIN obligation cost for gasoline produced or imported into the United States. Figures 14 and 15 show the price differentials between diesel and heating oil and diesel and jet fuel and the RIN obligation costs associated with diesel fuel. The correlation between the price differences of these similar fuels and the RIN obligation costs suggests that obligated parties were generally able to increase the price they charge for the RIN obligated petroleum products they sell for use as transportation fuel in the US to help recover their compliance costs under the RFS program.[28]

[27] Futures prices are for December of the current year, i.e. December 2012 throughout 2012, December 2013 throughout 2013, and December 2014 throughout 2014

[28] Or alternatively, that the market price adjusted to reflect the RIN cost just as it adjusts to reflect changes in crude oil prices and other costs

Figure 13
RBOB Gasoline vs. Euro-bob Oxy Futures Quotes (December Futures)



RIN Prices from OPISEthanol and Biodiesel Information Services
RBOB Gasoline vs. Euro-bob Oxy Futurer prices from CME Group

Figure 14
ULSD Price Minus Heating Oil Price (New York Harbor) and Per Gallon RIN Cost

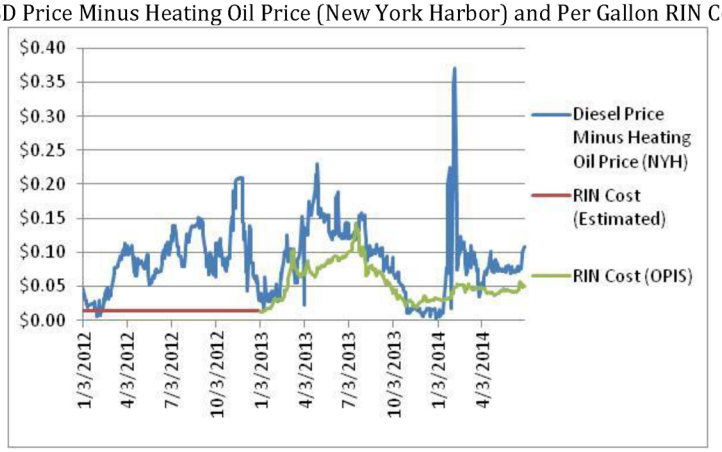
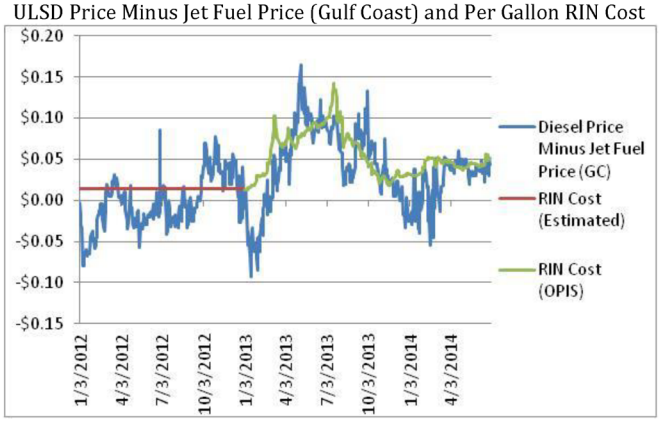


Figure 15
ULSD Price Minus Jet Fuel Price (Gulf Coast) and Per Gallon RIN Cost



The second area EPA examined to corroborate the results of our example scenarios was the pricing of ethanol, unblended gasoline, and blended fuels (such as E10 or E85) at the wholesale level. Examining this data should indicate whether or not the value of the RIN, which can be separated by the fuel blender when the ethanol is blended to produce a transportation fuel, is reflected in the wholesale price of the blended fuels. If the wholesale price for blended fuels, such as E10 and E85, is equal to or slightly greater than the volume weighted average price of neat ethanol (E100) and clear gasoline (E0) it would indicate that the RIN value is not reflected in the wholesale price of the blended fuels.[29] In this scenario, the fuel blender would retain any value associated with the separation and sale of the RIN. If, however, the price for the blended fuels was lower than the volume weighted average of neat ethanol and clear gasoline, it would indicate that the RIN value was at least partially reflected in the price of the blended fuels at the wholesale level.

The fuel blender can only profitably sell a blended fuel for less than the component costs of that fuel if they are realizing value elsewhere. Fuel blenders are able to separate and sell a RIN every time they blend a gallon of renewable fuel, and the RIN value can be used to discount the price of the blended fuel and offer it at a competitive price. Alternatively, the fuel blenders may attempt to retain some or all of the RIN value, especially in less competitive markets. As in the case where we examined the price delta between similar fuels with and without RIN obligations, if the difference between the blended fuel price and the volume weighted average price of neat ethanol and clear gasoline was approximately

[29] This is true when RIN prices are relatively high. When D6 RIN prices are only a few cents any blended fuel discount due to the sale of the RIN may be masked by a mark-up of the fuel price at the fuel blender

equal to the RIN value for each of these fuels, this would provide support for the argument that the RIN value is the basis for this difference.

For this analysis we used terminal pricing information from Des Moines, Iowa. We chose to use Des Moines for two reasons. First, unlike many terminals in other states, clear gasoline (E0) is readily available in Iowa at the wholesale level. Knowing the price of clear gasoline allows us to see RIN price impacts on petroleum blendstocks before they are blended with ethanol. Second, Iowa contains a relatively high number of ethanol plants that currently market E85 fuel blends, making it more likely to represent a competitive marketplace for E85. This increase in the competition in the E85 wholesale market increases the likelihood that the RIN value will be reflected in the price of E85 at the wholesale level (see Figure 6, where E85 sales in Iowa increased when RIN prices were high). In other markets, where blenders of E85 face less competition, they may be able to retain more of the RIN value for these higher level ethanol blends rather than reflecting them in the wholesale pricing of these blends.[30] Figure 16 shows the pricing of neat ethanol (E100), clear gasoline (E0), and E10 at the Des Moines terminal, as well as the average price for E85 available at the terminal and direct from ethanol production facilities.[31] Figure 17 compares the difference between the reported price of E10 and the calculated price using a volume weighted average of the component fuels (E100 and E0)[32] to the RIN value associated with E10.[33] Figure 18 compares the difference between the reported price of E85 and the calculated prices using a volume weighted average of the component fuels (E100 and E0)[34] to the RIN value associated with E85.[35]

[30] Over time, however, we would expect markets that are currently relatively uncompetitive to see increased competition and a decreasing opportunity to withhold RIN value from fuel costomers

[31] Prices for E0, E10, and E100 are Des Moines rack average prices, provided to EPA by Iowa RFA. Price for E85 is the average of all prices listed on the Iowa RFA Wholesale E85 Price Listing website (http://www.iowarfa.org/E85PastPriceProgram.php)

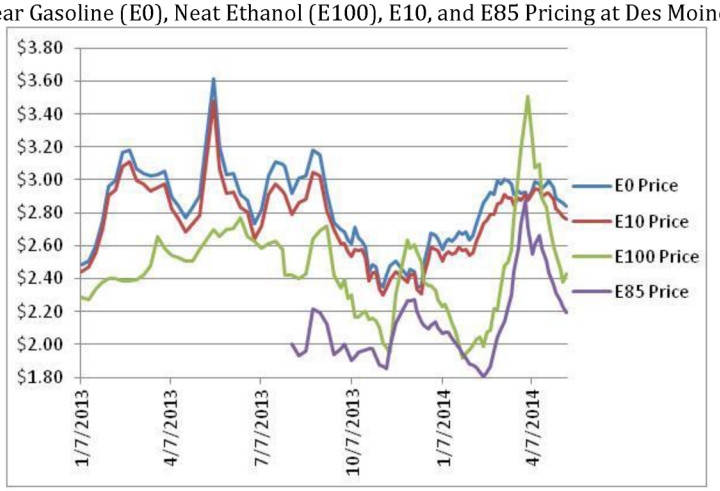
[32] Component E10 price = 0.9 * E0 price + 0.1 * E100 price

[33] E10 RIN value = 0.1 * D6 RIN price (RIN price information from OPIS Ethanol and Biodiesel Information Service

[34] Component E85 price = [1 – Ethanol Content] * E0 price + [Ethanol Content] * E100 price; Ethanol content is calculated based on the weekly average of all E85 offerings reported by Iowa RFA

[35] E85 RIN value = [Ethanol content of E85] * D6 RIN price (Ethanol content is calculated based on the weekly average of all E85 offerings reported by Iowa RFA ; RIN price information from OPIS Ethanol and Biodiesel Information Service

Figure 16
Clear Gasoline (E0), Neat Ethanol (E100), E10, and E85 Pricing at Des Moines



Fuel Prices from Iowa RFA (E85 Prices only available after August 8, 2014)

Figure 17
E10 Discount to Component Fuels vs. E10 RIN Value

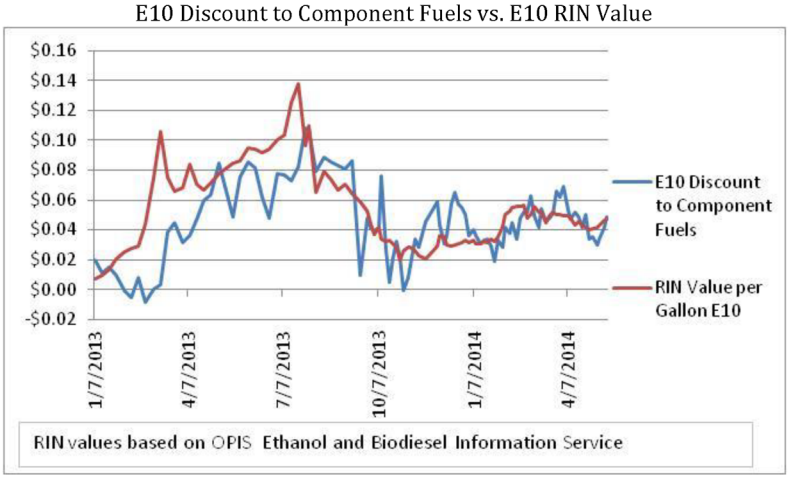
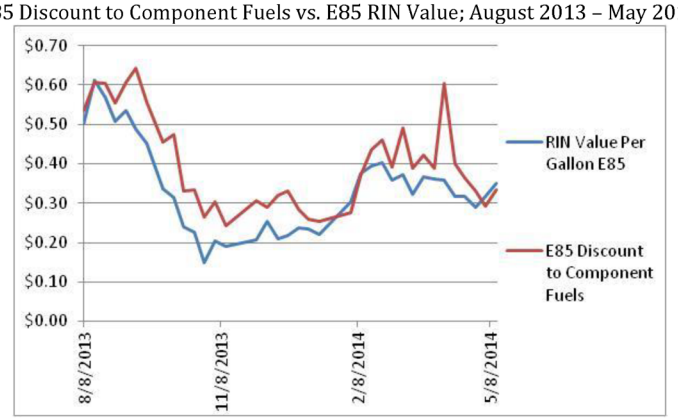


Figure 18
E85 Discount to Component Fuels vs. E85 RIN Value; August 2013 – May 2014



In reviewing the available data, it appears that, as predicted by scenarios in the previous section, the blended fuel prices at the wholesale level generally reflect the changing RIN prices. To state this another way, when determining the price at which to offer blended fuels, the data suggests the fuel blenders are taking into account the value received in the sale of the RIN. This further supports EPA's argument that, if all else remains equal, rising RIN prices may impact the relative pricing of fuel blends containing differing amounts of renewable fuel, but should not result in overall increases to blended fuel prices. We expect that these dynamics will hold when there are generally competitive markets for blended fuels at the wholesale and retail level. This is currently the case for much of the United States for E10 blends, however in most of the United States there is limited competition for E85 at both the wholesale and retail level. In their efforts to maximize profit and pay off their infrastructure investment, E85 wholesalers and retailers who face less competition may choose to withhold some or all or the RIN value if they believe that any increased sales volumes that result from lower priced E85 will be insufficient to overcome the lower per gallon profit margin. These high per-gallon profit margins may over time result in new parties entering the E85 wholesale or retail marketplace, and ultimately greater competition and lower E85 fuel prices for customers.[36]

While EPA has examined the available data in the marketplace to answer these two questions (Are obligated parties increasing the price of their RIN obligated fuels to recover RIN costs? And are fuel wholesalers reflecting the price of the RIN in their blended fuels?) we have not conducted a comprehensive analysis to address the question of whether or not a causal relationship between RIN prices and retail gasoline prices could be observed. EPA is aware, however, of others who have directly explored this issue, including an analysis

released by the Renewable Fuels Association conducted by Informa Economics[37] and Scott Irwin and Darrel Good of FarmDoc Daily,[38] and concluded that RIN prices in 2013 did not cause higher gasoline retail prices.

RIN Price Impacts on Merchant and Integrated Refiners

After RIN prices surged in 2013, several parties argued that high RIN prices put merchant refiners (refiners that do not blend the petroleum blendstocks they produced with renewable fuels) at a competitive disadvantage relative to integrated refiners (refiners who do own fuel blending operations). EPA maintains that this conclusion is based on a flawed analysis of the RIN and transportation fuel markets. Specifically, this argument rests on the assumption that parties who blended renewable fuels with petroleum-based fuels to produce transportation fuel were able to separate RINs from renewable fuel and obtain them at a lower cost, while merchant refiners were forced to buy RINs at a higher market price. Those who raised this concern argued that while this dynamic existed even when RIN prices were low, the high RIN prices in 2013, specifically the high D6 RIN prices, put them at a significant competitive disadvantage.

The misunderstanding at the heart of this flawed conclusion concerns the manner in which merchant refiners acquire RINs, which may differ from the method generally used by integrated refiners. Because merchant refiners do not own fuel blending infrastructure, they generally purchase RINs from fuel blenders who do not have RIN obligations, or other parties who have RINs in excess of their obligations. For these merchant refiners there is a direct and obvious cost of purchasing RINs to satisfy their obligations. Integrated refiners generally obtain RINs by purchasing renewable fuels with attached RINs. As a result, integrated refiners are not paying a separate price for the RINs they acquire, but rather simultaneously purchasing both the renewable fuel and the associated RINs. At the same time, the increased value merchant refiners receive for their petroleum fuel is hidden in the market pricing of the fuels. Several merchant refiners have claimed that they cannot increase the price of their petroleum products, as the price they receive is determined by market listings such as NYMEX. However, even if true, the higher NYMEX price for gasoline sold in the United States relative to the price of gasoline in foreign markets shown in Figure 13 suggests that the NYMEX prices reflect the RIN cost incurred by refiners who sell petroleum products into the U.S. market. While these merchant refiners may simply be receiving prices for their products based on market listings, the data we have reviewed

[37] "Analysis of Whether Higher Prices of Renewable Fuel Standard RINs Affected Gasoline Prices in 2013." Informa Economics. January 2014. In examining the available information, Informa Economics concluded that RIN prices did not have a causal relationship with gasoline prices. Other factors, notably the refiner crude oil composite acquisition cost, were found to have a causal relationship with gasoline prices in 2013. While this paper does not explore the mechanics of the RIN and transportation fuels market, and therefore cannot be used to verify EPA's understanding of the RIN market dynamics, it nevertheless supports our conclusion that high RIN prices did not cause higher gasoline prices in 2013.

[38] Irain, Scott, and Darrel Good. "High Gasoline and Ethanol RIN Prices: Is There a Connection?" FarmDoc Daily. Department of Agriculture and Consumer Economics, University of Illinois Urbana-Champaign, 27 Mar. 2013. Web. 10 Sept. 2014.

suggests that the market has adjusted to increased D6 RIN prices and they are nevertheless receiving a higher price for their products that generally reflects their RIN costs. If this is the case, exempting merchant refiners (or any other obligated party) from their RIN obligation while maintaining RIN obligations for other obligated parties would allow the exempted parties to benefit from higher petroleum prices that reflect RIN costs while incurring no RIN costs themselves. This would allow the exempted parties to benefit from increased profit margins relative to other obligated parties as a direct result of the RFS program.

The data EPA has analyzed also indicates that parties that blended renewable fuels were not able to retain the full RIN value. Rather, the price received for a RIN was effectively used to subsidize the price of the renewable from which it was separated, and the price of blended fuels generally reflected this lower renewable fuel price. As discussed in the preceding section and shown in Figures 17 and 18 above, the data EPA has reviewed for Iowa shows that the price of blended fuels at the wholesale level in 2013 was generally less than the weighted average prices of the component fuels. This difference was related to the RIN value associated with the renewable fuel content in these blended fuels. This suggests that fuel blenders who purchased renewable fuels with attached RINs, whether independent or owned and operated by integrated refiners, were selling the renewable fuels for significantly less than the purchase price after the renewable fuels had been blended to produce transportation fuel and the RINs had been separated. Whether the integrated refiners attribute the cost associated with selling the renewable fuels for less than the price they paid to purchase these fuels to their renewable fuel acquisition operations, blending operations, or refining operations, they are subject to a cost for acquiring RINs just like the merchant refiners as long as they are selling renewable fuels at a price lower than the purchase price. If the integrated refiners were to attempt to recover the full purchase price of the renewable fuels in the price of the blended fuel they would likely not be competitive with the independent fuel blenders as the available data suggests blended fuel prices generally reflect discounted renewable fuel prices (net the RIN value).

We further believe that the obligated parties were generally able to recover this increase in the cost of meeting their RIN obligations in the price they received for their petroleum-based products in 2013. We do not argue the fact that higher RIN prices lead to greater RIN acquisition costs for some obligated parties. We do believe, however, that these higher costs have a similar impact on all obligated parties. This includes not only merchant and integrated refiners, but also fuel importers who may import only a single product, such as gasoline or diesel fuel, as the primary mechanism for recovering the RIN cost is through the sales price of the petroleum based blendstocks. There are a number of factors that may impact an individual obligated party's RIN costs, including their RIN purchasing strategy (contract v. spot purchases, separated RINs v. RINs attached to renewable fuels), investments in renewable fuel production and blending infrastructure, geographic location, and many others unique to each obligated party's business. While changing RIN prices may result in profit or costs for one obligated party relative to another, these impacts are largely due to individual business decisions rather than the systematic design of the RFS program. In this way the increasing RIN prices are similar to an increase in the price of crude oil. A rise in the price of crude oil has a significant impact on a refiners cost to produce gasoline

blendstocks, but it will likely not impact their competitiveness, as all refiners are similarly impacted. The impacts on individual refiners may have slight variations due to crude oil purchase contracts or crude supply options, but these differences are indicative of market positions taken by individual refineries rather than a systematic competitive disadvantage.[39]

In the preceding section we examined available data on the price obligated parties received for similar fuel types with and without RIN obligations. In demonstrating that there was a difference in the prices for these fuels, this data, shown in Figures 13 and 16, suggests that obligated parties are generally able to recover the cost of meeting their RIN obligations in the price of their petroleum blendstocks. If this were not the case, we would expect that merchant refiners would have an incentive to export the gasoline and diesel fuel they produce or to increase production of heating oil or jet fuel, as these fuels do not incur a RIN obligation. If a significant volume of fuel was exported to foreign markets this would create a shortage of supply in the U.S., and prices in the U.S. would rise. These higher domestic prices would provide a price signal to increase domestic production, increase fuel imports, or reduce exports to meet the demand, despite this fuel being subject to an RVO.

Finally, claims that high RIN prices put merchant refiners at a competitive disadvantage relative to integrated refiners ignore the compliance flexibility built into the RIN system. Obligated parties, including independent refiners, may acquire RINs by purchasing renewable fuel with attached RINs and retaining the RINs after selling or blending the renewable fuel, by purchasing separated RINs on the RIN spot market, or through contract arrangements. A merchant refiner's status does not mandate that the refiner purchase only separated RINs. Rather, all obligated parties can choose how and when to acquire RINs to comply with the RFS program. To the extent that merchant refiners choose—for economic or other reasons—to limit themselves to purchasing RINs on the market, that choice is their own, and not one required by EPA's rule. If merchant refiners believe that owning and operating blending operations, or purchasing renewable fuels, separating and retiring the RINs, and reselling the renewable fuel without RINs would present a significant financial or strategic advantage, they may, and generally would, enter the marketplace in this capacity.

Conclusion

In this document we have examined the RIN, renewable fuels, and transportation fuels marketplace. We have explored the question of the cause of elevated D6 RIN prices observed in 2013 and shown that the E10 blendwall was a significant factor in these rising RIN prices. Due to the complexity of the RIN market, we cannot precisely predict the future

[39] There are significant similarities between the RIN markets and how refiners make their crude oil purchasing decisions. Integrated refiners may process their own crude or procure it from the open market, while independent refiners purchase all of their crude oil. Refiners, both integrated and independent, are differently situated to process or option different crudes. They have differing business strategies for making these decisions that may impact their relative profitability.

price of D6 RINs. We would not, however, expect the D6 RIN price to return to the prices experienced from 2010 to 2012 unless the cost of production of ethanol or other renewable fuels fell sufficiently below the cost of gasoline on an energy-equivalent basis.

We also examined data from 2013 which suggested that rising RIN prices did not result in an increase in retail transportation fuel prices in 2013 (considering both gasoline and diesel together), due to the lower net cost of renewable fuels enabled by the high RIN prices. While higher RIN prices increase the cost of RFS compliance for obligated parties purchasing separated RINs, these obligated parties generally recover these costs in the price of their petroleum blendstocks. As a result, a slight decrease in the price of ethanol-gasoline blends, which contain a relatively large amount of renewable fuels, is expected to be offset by an increase in the price of diesel fuel, which generally contains lower levels of renewable fuel. This does not necessarily mean that there is no cost to increasing the volume of renewable fuels required to be blended into the transportation fuel pool. If renewable fuels cost more on an energy-equivalent basis than the petroleum fuels they displace, as they did in 2013, there is a cost to using these renewable fuels. The higher the required volume of these fuels, the higher this cost will be. As a result, blending increasing volumes of renewable fuels likely increased the total cost of transportation fuel in the United States in 2013, relative to a scenario where there was no mandate for renewable fuels.

Finally we examined how merchant refiners and integrated refiners were impacted by high RIN prices. The available data suggests that while there may be some variation in how high RIN prices impact individual obligated parties due to differing business decisions, RIN acquisition strategies, and many other factors, the structure of the RFS program does not cause a systematic competitive advantage for one type of refiner or the other. The RIN, renewable fuel, and transportation fuel market is complex, and there are limitations to the available data. EPA will continue to monitor market prices and impacts over time in an attempt to better understand the dynamics and watch for signs of market disruption. Based on available data, however, the RIN market seems to be functioning generally as expected; providing an incentive for the continued growth of renewable fuels in the transportation fuel market without causing overall increases to the retail price of transportation fuel.

Denial of Petitions for Rulemaking to Change the RFS Point of Obligation

EPA United States Environmental Protection Agency

Denial of Petitions for Rulemaking to Change the RFS Point of Obligation

Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

EPA United States Environmental Protection Agency

EPA-420-R-17-008
November 2017

Executive Summary

The Environmental Protection Agency (EPA) has received several petitions requesting that the EPA initiate a rulemaking process to reconsider or change 40 CFR 80.1406 identifying refiners and importers of gasoline and diesel fuel as the entities responsible for complying with the annual percentage standards adopted under the Renewable Fuel Standard (RFS) program. This "point of obligation" for the RFS program was established through a notice-and-comment rulemaking in 2010 based on the statutory direction in Section 211(o)(3)(B)(ii)(I) and (C) of the Clean Air Act (CAA) to impose the renewable fuel obligation on "refineries, blenders and importers, as appropriate," while also "prevent[ing] the imposition of redundant obligations." This statutory provision also allows EPA to modify the point of obligation if the designated parties are no longer appropriate. While evaluating petitions on the RFS point of obligation, EPA also evaluated whether the current obligated parties remain the appropriate obligated parties under CAA 211(o)(3)(B)(ii)(I). EPA has concluded that it is appropriate to retain the current regulatory requirement designating refiners and importers as the parties responsible for compliance with RFS standards because we again believe refiners and importers are the appropriate obligated parties.

In their initial petitions, the petitioners all asked to have the point of obligation shifted from refiners and importers, but they differed somewhat in their suggestions for alternatives. Some requested that the EPA shift the point of obligation from refiners and importers to those parties that blend renewable fuel into transportation fuel. Others suggested that it be shifted to those parties that hold title to the gasoline or diesel fuel immediately prior to the sale of these fuels at the terminal (these parties are commonly called the "position holders"), or to "blenders and distributors." All petitioners argued, among other things, that shifting the point of obligation to parties downstream of refiners and importers in the fuel distribution system would align compliance responsibilities with the parties best positioned to make decisions on how much renewable fuel is blended into the transportation fuel supply in the United States. Some of the petitioners further claimed that changing the point of obligation would result in an increase in the production, distribution, and use of renewable fuels in the United States and would reduce the cost of transportation fuel to consumers.

On November 10, 2016, the EPA published a proposed denial of requests to initiate a rulemaking process to reconsider or change the regulations at 40 CFR 80.1406. See Proposed Denial of Petitions for Rulemaking to Change the RFS Point of Obligation, EPA-HQ-OAR-2016-0544, hereinafter "proposed denial." The EPA solicited comment from interested stakeholders on the proposed denial. Acting on the request of stakeholders, the EPA extended the public comment period to February 22, 2017. The EPA received over 18,000 comments submitted to the docket. The EPA's response to significant and relevant comments is provided within this document. Notwithstanding the different suggestions for shifting the point of obligation that were expressed in the initial petitions, in their comments, all petitioners suggested that the definition of "obligated party" in 40 CFR 80.1406 should be changed to put the obligation for compliance with the RFS percentage standards on "position holders."[1]

[1] The Small Refiners Coalition and others, in comment, argued in the alternative that the point of obligation could be placed on blenders if the EPA lacks the authority to place the point of obligation on "position holders."

The Administrator is today denying all petitions seeking initiation of a rulemaking process to change the definition of obligated party under the RFS program. Our conclusion reflects consideration of the alleged benefits that Petitioners and some commenters have suggested would ensue from a change in the point of obligation, as well as negative impacts that the EPA believes would result from such a change. In our judgment, it does not appear that the record before the Agency indicates that a change in the point of obligation would result in net overall benefits to the program. In addition, however, we believe that changing the point of obligation at this time would be very disruptive to the program, and likely the fuels marketplace as well, undermining long settled expectations and the program stability and certainty that are critical to both short- and long-term success of the program. Thus, even if there were some marginal net benefits to changing the point of obligation, we believe that the disruptive effects of a change at this time would still warrant denial.

As discussed in more detail below, the current structure of the RFS program is working to incentivize the production, distribution, and use of renewable transportation fuels in the United States, while providing obligated parties a number of options for acquiring the RINs they need to comply with the RFS standards. We do not believe that the petitioners have demonstrated that changing the point of obligation would likely result in increased use of renewable fuels. Based on the information currently available to the EPA, changing the point of obligation would not address challenges associated with commercializing cellulosic biofuel technologies and the marketplace dynamics that inhibit the increase of fuels containing higher levels of ethanol, two of the primary issues that limit the rate of growth in the supply of renewable fuels today. While we do not anticipate a benefit from changing the point of obligation, we do believe that such a change would significantly increase the complexity of the RFS program, which could negatively impact its effectiveness. EPA is also not persuaded, based on our analysis of available data, including that supplied by petitioners and commenters, by arguments that merchant refiners[2] are disadvantaged under the current regulations in comparison to integrated refiners in terms of their costs of compliance, nor that other stakeholders such as unobligated blenders are receiving windfall profits. Finally, EPA does not interpret the Clean Air Act as authorizing it to place the point of obligation on distributors or on those "position holders" who are neither refiners not blenders. For all of these reasons, as further described below, EPA is denying the petitions for reconsideration.

The point of obligation has been placed on refiners and importers since inception of the RFS regulatory program, in 2007. We also believe that in considering whether to embark on a rulemaking exercise to change the regulations, that it is appropriate for EPA to take into consideration the consequences of enacting a change at this time. In the short term we believe that initiating a rulemaking process to reconsider or change the point of obligation would work counter to the program's goals by causing significant upheaval and uncertainty in the fuels marketplace. Such a dynamic would likely cause delays to the investments necessary to expand the supply of renewable fuels in the United States, and strand past investments, particularly investments in cellulosic biofuels, the category of renewable fuels from which much the majority of the statutory volume increases in future years is expected.

[2] Merchant refiners are those that market only a minority of the fuels they refine (and in some cases do not market any fuel), often selling the fuel to other parties at the refinery gate for distribution and marketing.

In addition, changing the point of obligation could disrupt investments reasonably made by participants in the fuels industry in reliance on the regulatory structure the agency established in 2007 and confirmed in 2010. It could also lead to restructuring of the fuels marketplace as newly obligated parties alter their business practices to avoid compliance obligations. For example, if the point of obligation were changed to "position holders," we believe that parties who previously were "position holders" may choose to instead purchase fuel under contract "below the rack" instead of "above the rack" to avoid the overhead compliance costs associated with being an obligated party under the RFS program. We believe these changes would have no beneficial impact on the RFS program or renewable fuel volumes and would decrease competition among parties that buy and sell transportation fuels at the rack, potentially increasing fuel prices for consumers and profit margins for refiners, especially those not involved in fuel marketing.

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I. Introduction

On March 26, 2010, the Environmental Protection Agency ("EPA") issued a final rule (the "RFS2 Rule")[3] establishing regulatory amendments to the renewable fuel standards ("RFS") program regulations to reflect statutory amendments to Section 211(o) of the Clean Air Act ("CAA" or "the Act") enacted as part of the Energy Independence and Security Act of 2007. These amended regulations included 40 CFR 80.1406, imposing the obligation for compliance with the RFS annual standards on refiners and importers of gasoline and diesel fuel.[4] These entities are referred to in the RFS regulations as "obligated parties." Beginning in 2014, some obligated parties and other stakeholders have questioned whether 40 CFR 80.1406 should be amended, and a number of them have filed formal petitions for reconsideration or revision of the definition of "obligated party" in 40 CFR 80.1406, or petitions for rulemaking to amend the provision.[5] Those parties filing petitions for reconsideration also initiated legal challenges of the 2010 rule, alleging that new grounds have arisen enabling them to do so notwithstanding expiration of the 60-day time period generally provided under CAA 307(b) for challenges to CAA rules.[6] These suits have been stayed pending final action by the EPA on the administrative petitions for reconsideration.

Some petitioners[7] that challenged the rule establishing RFS standards for 2014, 2015 and 2016, alleged both that the EPA had a duty to annually reconsider the appropriate obligated parties under the RFS program and that it was required to do so in response to comments suggesting that it could potentially avoid or minimize its exercise of the inadequate domestic supply waiver authority if it did so. In a recent ruling in that litigation, the United States Court of Appeals for the District of Columbia Circuit declined to rule on the matter, and instead indicated that the EPA could address the matter either in the context of a remand of the 2014-2016 rule ordered on

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[3] 75 Fed. Reg. 14670.

[4] In imposing the fundamental RFS compliance obligation on refiners and importers, the 2010 rule simply continued the practice established under the original RFS program regulations adopted in 2007. See 72 Fed. Reg. 23900 (adopting 40 CFR 80.1106). However, the 2010 rule broadened the number of regulatory parties somewhat to reflect the new EISA requirement imposing blending requirements on diesel fuel, in addition to gasoline, that is used as transportation fuel.

[5] On January 27, 2014, Monroe Energy LCC ("Monroe") filed a "petition to revise" 40 CFR 80.1406 to change the RFS point of obligation, and on January 28, 2016, Monroe filed a "petition for reconsideration" of the regulation. On February 11, 2016, Alon Refining Krotz Springs, Inc.; American Refining Group, Inc.; Calumet Specialty Products Partners, L.P.; Lion Oil Company; Ergon-West Virginia, Inc.; Hunt Refining Company; Placid Refining Company LLC; U.S. Oil & Refining Company (the "Small Refinery Owners Ad Hoc Coalition" or "Coalition") filed a petition for reconsideration of 40 CFR 80.1406. On February 12, 2016, Valero Energy Corporation and its subsidiaries ("Valero") filed a "petition to reconsider and revise" the rule. On June 13, 2016, Valero submitted a petition for rulemaking to change the definition of "obligated party." On August 4, 2016, the American Fuel and Petrochemical Manufacturers ("AFPM") filed a petition for rulemaking to change the definition of "obligated party." On September 2, 2016, Holly Frontier also filed a petition for rulemaking to change the definition of "obligated party." These parties are collectively referred to herein as "the Petitioners."

[6] See Monroe Energy LLC v. EPA, #14-1014. (D.C.Cir. 2014); Monroe Energy LLC v. EPA, #16-1032. (D.C.Cir. 2016); Alon Refining Krotz Springs, Inc. et al v. EPA. #16-1052. (D.C.Cir. 2016); Valero Energy Corperation v. EPA, #16-1055 (D.C.Cir. 2016).

[7] Petitioners Valero Energy Corporation, Alon Refining Krotz Spring, Inc., et al., Monroe Energy LLC, and American Fuel and Petrochemical Manufacturers raised arguments related to the RFS point of obligation in their challenges to EPA's rule setting the RFS percentage standards for 2014, 2015, and 2016.

other grounds, or in response to the administrative petitions.[8] As noted above, the EPA is denying the petitions seeking a change in the definition of "obligated parties." The EPA also is re-affirming that the existing regulation applies in all years going forward unless and until it is revised. The EPA does not agree with the petitioners in the *ACE* case that the statute requires annual reconsideration of the matter and, although the EPA has the discretion under the statute to undertake such annual reevaluations, the EPA declines to do so since we believe the lack of certainty that would be associated with such an approach would undermine success in the program. [9,10]

It appears that the petitions for reconsideration of 40 CFR 80.1406 do not meet the statutory criteria for such petitions set forth in CAA 307(d)(7)(B).[11] However, for purposes of this decision document, we will treat all petitions suggesting a change in the RFS point of obligation as petitions for a rulemaking to accomplish the change(s) requested.[12] This evaluation provides a consolidated response to all petitions (however styled) and other requests we have received that seek a change in the RFS point of obligation. For the reasons stated herein, we are denying all requests to initiate a rulemaking to change the current regulation.

In considering the petitions to change the point of obligation in the RFS program, the EPA has reviewed the large amount of information submitted by the petitioners and has met with those who requested meetings and other interested parties. The EPA has also met, and heard from, other participants in the RFS program, including other obligated parties, manufacturers of renewable fuel, and fuel retailers, who are opposed to revising the regulations. The EPA received over 18,000 comments submitted on its proposed denial, and has reviewed and considered the information submitted. Many of these comments were part of mass comment campaigns, and contained similar messages; however, the EPA received approximately 350 unique comments. See Docket EPA-HQ-OAR-2016-0544. Many commenters presented similar arguments to those put forth by petitioners in their initial requests for reconsideration or rulemaking. EPA also received many comments supporting EPA's proposed denial. Where significant new arguments or information were presented in comments, the EPA has addressed

[8] See *Americans for Clean Energy v. Environmental Protection Agency*, *864 F.3d 691* (D.C. Cir. 2017) ("*ACE*").
[9] The EPA interprets the CAA to allow the designation or redesignation of "appropriate" obligated parties to occur at any time, as the phrase "as appropriate" is broad and confers significant discretion. While the statute specifies that the percentage standards must be applicable to refineries, importers, or blenders as appropriate, it does not say that EPA must annual reevaluate the matter.
[10] Nevertheless, the EPA could consider changes to the definition of "obligated party" in the future, based on significant new facts or analysis. Given the time pressure associated with its annual standards rulemakings, EPA expects that any such consideration would not occur in the context of those rulemakings.
[11] Petitioners had an opportunity to submit comments on the point of obligation in both the 2007 and 2010 rulemakings when the current approach was adopted. The possible impact of this decision on incentivizing growth in renewable fuel use, including incentivizing growth after the clearly anticipated widespread use of ethanol at E10 levels, could have been raised in comments on those rules. Furthermore, to the extent the petitions are based on grounds arising more than 60 days after promulgation of the rule, such grounds are not a proper basis for a petition for reconsideration under CAA 307(d)(7)(B).
[12] We take no position at this time on whether petitions associated with judicial challenges to the RFS2 rule satisfy the criterion in CAA 307(b)(1) that they be "based solely on grounds arising after" the 60-day period following notice of promulgation of CAA rules, or whether the petitions for review were filled within 60 days after new grounds arose. We have considered the substance of the administrative petitions filed with the Agency whether or not the criteria specified in CAA 307(b)(1) for late challenges to Agency rules are satisfied.

those within this document. EPA also received a number of comments on the RFS point of obligation in response to its proposed 2018 RFS requirements.[13] EPA has reviewed those comments, and where appropriate, addressed them within this document.

Who should be designated an "obligated party" under the RFS program is an issue that has generated significant debate, especially in the last few years, and one that raises complex questions about the appropriate structure of the RFS program. The various parties have presented a wide range of different information and analyses, and some have offered different interpretations of the same information and analyses. The EPA's primary consideration here is whether or not the requested change(s) would improve the effectiveness of the program to achieve Congress's goals, which are to increase energy security and reduce emissions of air pollutants by requiring that increasing volumes of the nation's transportation fuel be comprised of renewable fuels. Each of the individual elements discussed in the analysis below, such as the number and nature of the parties that would become obligated if the EPA were to grant the petitioners' requests, are considered in light of how each of these elements are expected to contribute towards or detract from the overall effectiveness of the program. EPA also has considered the impact of the current regulatory structure, and the proposed alternatives on the groups that would be regulated under these options, with the objective of determining whether the current or alternative options may be more equitable or the burdens more facilely borne.

CAA 211(o)(3)(B)(ii)(I) provides that the annual renewable fuel obligations shall "be applicable to refineries, blenders, and importers, as appropriate." The use of the term "appropriate" in determining the obligated parties provides significant discretion conferred upon EPA. *See Michigan v. EPA*, 135 S. Ct. 2699, 2707 (2015) (explaining that "'appropriate' is the classic broad and all-encompassing term" and "leaves agencies with flexibility"). EPA has discretion not only in determining when to modify the definition, but also under what circumstances. After consideration of the information currently before EPA, and as discussed in this document, EPA continues to believe that the point of obligation is appropriately placed on refiners and importers of transportation fuel. As expressed in Section II below, EPA believes the current designation of obligated parties is working to achieve the goals of the RFS program.

Additionally, EPA evaluated the impact of a possible change to the definition of "obligated party" on consumers, including potential impacts on fuel prices. As described in more detail below, changing the point of obligation as proposed by petitioners and other stakeholders would significantly increase the number of obligated parties in the RFS program. Many of these newly obligated parties would be smaller companies or those that do not regularly conduct business in the RIN market, who are likely to be unfamiliar with the requirements of obligated parties under the RFS program. The administrative compliance burden of the RFS obligations would likely be proportionally greater for these smaller companies than current obligated parties (relatively larger refiners and importers of gasoline and diesel) who typically employ engineers, traders, accountants, attorneys, and auditors to demonstrate and verify compliance with the RFS and other regulatory programs. It would also increase EPA's burden in administering and enforcing the RFS program while at the same time opening up new opportunities for additional types of fraudulent behavior in a program that has already seen instances of fraud.

[13] See Docket EPA-HQ-OAR-2017-0091.

While petitioners generally claim that changing the point of obligation would result in the increased production, distribution, and use of renewable fuels in the United States, petitioners and commenters have failed to provide data that confirms these claims. We continue to believe that changing the point of obligation would at best result in a negligible increase in the production, distribution, and use of renewable fuels in the United States, and would more likely result in a decrease in the production, distribution, and use of these fuels. The EPA is also not persuaded, based on the record before us, by arguments that, under the current regulatory structure, merchant refiners are disadvantaged compared to integrated refiners in terms of their costs of compliance, nor that other stakeholders are receiving windfall profits. The costs of the RFS program are apportioned to all refiners and importers as a function of their production volume and generally are passed on to consumers. Finally, we believe that changing the point of obligation would do nothing to incentivize the research, development, and commercialization of cellulosic biofuel technologies critical for the growth of the RFS program in future years. Each of these issues is discussed in greater detail below.

A. Relevant Parties in the Fuel Market

Gasoline and diesel fuel are produced at domestic refineries or imported to the United States. There are a wide variety of paths and associated business models by which fuel reaches consumers. Refineries distribute some of the fuel they produce by truck directly from the refinery's loading rack. Refineries generally distribute their remaining production from the "refinery gate" through pipeline, barge, or rail, to distribution terminals. This fuel may be sold by the refinery when it leaves the "refinery gate" or at a location downstream from the refinery on its distribution path. All transportation fuel produced in the United States moves through the "rack."[14] The "rack" refers to the truck loading facility at a distribution terminal or refinery. Generally, wholesale purchasers, marketers or distributors receive fuel at the refinery or terminal rack and distribute that fuel to end users or retailers.[15] These parties may purchase fuel upstream of the terminal rack (e.g., directly from the refinery) and handle the logistics of fuel distribution themselves. They may instead purchase fuel at product terminals (either above or below the rack), relying on the refiner or other entity to handle all of the logistics and blending requirements, generally under contract. A "rack seller" is a party who owns fuel immediately before "the rack." The Internal Revenue Service collects excise tax from rack sellers. It defines rack sellers at the refinery rack as "refiners" and rack sellers at the terminal rack as "position holders." For simplicity, we have elected in this document to refer to all parties the IRS considers to be refiners or position holders as "position holders." All subsequent references to "refiners" in this document are to parties that refine petroleum products, whether or not they are rack sellers.

[14] For fuel imported into the United States, transportation fuel can move through a rack, or is tracked through registration as an "entrant."

[15] The term "fuel marketers" generally refers to parties that sell fuel to distributors or end users at the rack. "Fuel wholesalers" refers to parties that buy fuel in bulk, generally above the rack, and sell this fuel to retail station owners or end users, or distribute the fuel to retail stations they own. Fuel distributers refers to parties that transport fuel from the rack (either at terminals or refineries) to retail stations. Many different parties, including refiners, can operate as marketers, wholesalers, and/or distributers depending on market conditions, and the terms overlap considerably.

Some refiners are involved in fuel distribution, blending, and/or marketing as well as refining, and these entities are referred to as "integrated refiners." In contrast, "merchant refiners" are those that market a minority of the fuels they refine (and in some cases, do not market any fuel), often selling the fuel to other parties at the refinery gate for distribution and marketing. Most refiners engage in both practices: market a portion of their refined products, and sell fuel to other parties to distribute and market. Choices on which market segments to participate in and to what degree continually evolve over time in the industry, as profits among the various market segments likewise vary considerably over time.

"Downstream blenders" refers to parties who blend renewable fuel into gasoline or diesel fuel after the fuel has left the refinery. Downstream blending may occur at fuel terminals, bulk storage facilities, and at retail stations; in addition, renewable fuel can be "splash blended" into trucks. Blending of renewable fuel can also occur at the refinery, and this is often referred to as "upstream blending." The term "blender" can also be used to describe parties that combine non-renewable blendstocks downstream of the petroleum refinery to create finished gasoline.

B. Overview of RFS Obligations and Compliance

Each year the EPA calculates and establishes percentage standards for renewable fuel based on the volume targets established in the CAA (which are adjusted by the EPA as appropriate using its waiver authorities), and projections from the Energy Information Administration (EIA) of gasoline and diesel consumption for the coming year. To comply, obligated parties can purchase and blend the requisite volumes of renewable fuels into the petroleum derived transportation fuels they produce or import. However, to allow the market to function more efficiently and avoid market disruption, in implementing the statutorily-required credit program, and to assist obligated parties in meeting their individual renewable fuel volume obligations ("RVOs"), the EPA established, through a transparent public rulemaking process, a system for the generation and use of Renewable Identification Numbers ("RINs"). RINs are effectively credits that are generated upon production of qualifying renewable fuel and ultimately used by obligated parties to demonstrate compliance. Renewable fuel producers and importers generate and assign RINs to the renewable fuel they produce or import, and the RINs specify by a "D-code" the renewable fuel category applicable to the fuel, as determined by the feedstock used, fuel type produced and GHG emissions of the fuel, among other characteristics.[16] The assigned RINs accompany the fuel sold by renewable fuel producers and importers, and can only be separated from the fuel by

[16] There are 5 different D-Codes for RINs in the RFS program. D3 RINs can be generated for cellulosic biofuel, which must be produced from cellulosic biomass and achieve a GHG reduction of at least 60%. D4 RINs can be generated for biomass-based diesel (including both biodiesel and renewable diesel) and must achieve a GHG reduction of at least 50%. D5 RINs can be generated for advanced biofuels, which are any renewable fuel (other than ethanol derived from corn starch) that achieves a GHG reduction of at least 50%. D6 RINs can be generated for conventional renewable fuels (primarily corn ethanol) that achieve a GHG reduction of at least 20%, or for fuel within the established annual baseline volume from grandfathered production facilities. D7 RINs can be generated for cellulosic diesel, which is any fuel that meets the requirements for both cellulosic biofuel and biomass-based diesel.

a subsequent owner of the fuel who is an obligated party or a renewable fuel blender. Once separated, the RINs can be freely traded as a separate commodity from the renewable fuel. Obligated parties accumulate RINs over the course of the year, either by buying renewable fuel with assigned RINs that they separate and retain for compliance, or by buying RINs that others have separated on the open market.

The annual RVOs for a given obligated party are calculated by multiplying the obligated party's total annual production and import of gasoline and diesel fuel by the four annual percent standards.[17] Each obligated party must obtain sufficient RINs of each category to demonstrate compliance with its individual RVOs for the four annual standards. Compliance is accomplished on an annual average basis, through a single annual compliance report to the EPA identifying the RINs acquired and retired for that year's compliance. Thus, compliance under the RFS program requires the obligated parties to understand how to calculate their individual obligations based on the four standards, and then to plan for their annual compliance demonstration through RIN acquisition, through trading or through blending, over the course of the year. There are also associated registration, reporting and recordkeeping requirements.

C. Statutory and Regulatory History of the Point of Obligation

On July 29, 2005, Congress passed the Energy Policy Act of 2005 ("EPAct"), amending the Clean Air Act to create a statutory obligation for the use of renewable fuel in gasoline. The statute envisioned EPA adoption of annual percentage standards designed to increase renewable fuel use over time, and specified that the obligation for compliance with those standards would fall on "refineries, blenders, and importers, as appropriate." PL 109-58 August 8, 2005 and CAA 211(o)(3)(B)(ii)(I).

On September 22, 2006, the EPA published a proposed rule to establish the regulatory framework to implement the RFS program. The EPA proposed that obligated parties responsible for compliance with the annual percentage standards would be parties producing or importing gasoline: i.e., refiners and importers. The EPA specified that those blenders who only added renewable fuel to gasoline would not be obligated parties.[18] The EPA noted that there were approximately 1,200 ethanol blenders, as compared to 100-200 refiners and importers and stated that making ethanol blenders obligated parties would "greatly expand the number of regulated parties and increase the complexity of the RFS program beyond that which is necessary to carry out the renewable fuels mandate under the Act."[19]

The EPA received comments supportive of the EPA's proposed definition of obligated parties from the Society of Independent Gasoline Marketers of American and the National Association

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[17] There are separate, but nested, standards for cellulosic biofuel, biomass-based diesel, advanced biofuel, and renewable fuel.
[18] 71 Fed. Reg. 55552, 55573-4. Blenders who produce gasoline through combining blendstocks are considered refiners under EPA regulations and would therefore be obligated parties.
[19] Ibid at 55573.

of Convenience Stores (SIGMA/NACS), ExxonMobil, Baker Commodities, Griffin Industries, Methanol Institute (MI), and the American Petroleum Institute (API). The EPA did not receive any comments suggesting a different approach.[20]

On May 1, 2007, the EPA published a final rule establishing the regulatory RFS program. This rule, generally referred to as "RFS1", finalized the proposed definition of "obligated party" as refiners and importers of gasoline.[21] The program was expanded to apply to diesel fuel and otherwise significantly modified in 2007 through the Energy Independence and Security Act ("EISA"), Notably, Congress did not alter the provision specifying that compliance with the RFS percentage standards would be the responsibility of "refineries, blenders and importers, as appropriate." In enacting EISA, Congress stated that the goals of the statute include moving the United States toward "greater energy independence and security," and increasing "production of clean renewable fuels."[22] The amended statute established greenhouse gas emission reduction requirements for qualifying renewable fuels, and increasing annual renewable fuel volume targets to be achieved through application of annual percentage standards for four categories of renewable fuel by the EPA that also take into account the expected consumption of gasoline and diesel fuel. As was the case with EPAct, the amended statute required the EPA to establish a regulatory program, and specified that the program must include a number of program flexibilities, including a credit program for those who over-comply with the annual standards. The statute also specifically required a temporary exemption for small refineries (through 2010) that could be extended by the EPA either based on the results of a Department of Energy (DOE) study on impacts of the program on small refineries to be completed by December 31, 2008, or on a case-by-case basis upon demonstration by a small refinery of disproportionate economic hardship.

On May 26, 2009, the EPA proposed amendments to the RFS program regulations to reflect the significant statutory changes enacted as part of EISA.[23] The EPA proposed to retain the same approach to the RFS point of obligation as had been used in RFS1, but to expand it to include diesel producers and importers as obligated parties, consistent with EISA's addition of diesel fuel as an obligated fuel. The EPA also solicited comment on two possible alternatives: (1) making blenders who add oxygenate to RBOB and CBOB obligated parties with respect to those fuels rather than the refiners and importers of RBOB and CBOB,[24] and (2) moving the point of obligation for all gasoline and diesel to parties who supply finished transportation fuels to retail outlets or wholesale purchaser-consumer facilities. In raising these issues for public comment,

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[20] SIGMA/NACS commented that in the final rule the EPA should clearly distinguish between "blenders" and "oxygenate blenders" to avoid confusion or misinterpretation as to which parties have renewable volume obligations, and also urged the EPA to clarify that a party blending biodiesel into diesel fuel would not be considered a "blender" which has an RVO. In response to this comment, EPA pointed to its regulations which clearly only placed the obligation on refiners and importers that produce or import gasoline, including the limited subset of blenders who blend petroleum (i.e. non-renewable) blendstocks into finished gasoline. Regulation of Fuel and Fuel Additives: Renewable Fuel Standard Program Summary and Analysis of Comments. EPA420-R-07-006, 2-13—2-14.

[21] 72 Fed. Reg. 23900.

[22] Energy Independence and Security Act of 2007, PL 110-140, December 19, 2007.

[23] 74 Fed. Reg. 24904.

[24] Conventional blendstock for oxygenate blending (CBOB) and reformulated blendstock for oxygenate blending (RBOB) are produced by refineries and can be blended with 10% ethanol to produced finished conventional and reformulated gasoline respectively.

the EPA noted that the approach adopted under RFS1 was based on an expectation that there would be an excess of RINs at low cost, and that they would be freely traded between parties needing them such that obligated parties would have ample opportunity to acquire them. The EPA also explained that in adopting the approach under RFS1, the EPA had found that the designation of ethanol blenders as obligated parties would have greatly expanded the number of regulated parties and increased the complexity of the program beyond that which was necessary to carry out the fuels mandate required by the program. The EPA questioned whether, with the expanded mandates required under EISA, parties with excess RINs would tend to retain them for future compliance rather than sell them freely, and also hypothesized that most or all blenders would be regulated as RIN holders under the new program and questioned whether also making them responsible for compliance with the percentage standards could involve only a small additional burden. The EPA indicated that under the expanded program, there might be disparities in the ability of various obligated parties to acquire RINs. As a result of these considerations, and in light of the more complicated obligations required under RFS2, although proposing to retain the definition of obligated party (refiners and importers) from RFS1, the EPA also solicited comment on whether a change in that definition might be appropriate, and would more evenly align a party's access to RINs with that party's obligations under the RFS2 program.[25]

On March 26, 2010, the EPA issued a final rule establishing the amended RFS program structure reflecting the EISA amendments.[26] The EPA summarized the comments it had received on the point of obligation issue, noting that some refiners favored a change from the proposed approach of retaining the obligation on refiners and importers, while others did not. In contrast to the RFS1 proposal, EPA received many differing comments from interested stakeholders on this issue. Several parties suggested that blenders or other downstream parties should become obligated parties because they control blending and that without such a change refiners and importers would find it difficult to acquire RINs. Still others suggested that the obligation should be placed on parties who supply finished transportation fuels. Downstream blenders and other downstream parties, as well as renewable fuel producers and some members of the petroleum industry, generally opposed a change, citing the burden such a change would pose to small businesses, and the added unnecessary complexity it would add to the RFS program. The EPA concluded that the concerns expressed in the NPRM and in comments suggesting a change in the definition of obligated party, did not, on balance, warrant a change, stating:

> We continue to believe that the market will provide opportunities for parties who are in need of RINs to acquire them from parties who have excess. Refiners who market considerably less gasoline or diesel than they produce can establish contracts with splash blenders to purchase RINs. Such refiners can also purchase ethanol from producers directly, separate the RINs and then sell the ethanol without RINs to blenders. Since the RFS program is based upon ownership of RINs rather than custody of volume, refiners need never take custody of the ethanol in order to separate RINs from volumes that they own. Moreover, a change in the designation of obligated parties would result in a significant change in the number of obligated

[25] 74 Fed. Reg. 24904, 24963.
[26] 75 Fed. Reg. 14670.

> parties and the movement of RINs, changes that could disrupt the operation of the RFS program during the transition from RFS1 to RFS2.[27]

Nevertheless, because concerns over the liquidity of the RIN market still existed at the time, the EPA also stated that "[w]e will continue to evaluate the functionality of the RIN market [and] [s]hould we determine that the RIN market is not operating as intended, driving up prices for obligated parties and fuel prices for consumers, we will consider revisiting this provision in future regulatory efforts."[28]

The EPA promulgated 40 CFR 80.1406 stating that "[a]n obligated party is any refiner that produces gasoline or diesel fuel within the 48 contiguous states or Hawaii, or any importer that imports gasoline or diesel fuel into the 48 contiguous states or Hawaii during a compliance period."

As mentioned above, in requesting that the EPA reconsider the point of obligation for the RFS program, petitioners claim that the justifications given by the EPA in the final 2007 and 2010 rules that placed the point of obligation on the refiners and importers of gasoline and diesel are no longer valid. After providing notice and opportunity for comment, and after careful review and consideration of the comments received, we disagree that a change to the RFS point of obligation is warranted, for the reasons described below.[29]

In establishing the RFS program, Congress put in place a policy to effect a substantial transformation in the fuels market; stakeholders on all sides have strongly held views on whether and how that transformation should occur. However, nearly all stakeholders have communicated to the EPA about the desire for greater certainty and stability in the RFS program. As discussed further below, the EPA believes that a change in the point of obligation would be a substantial disruption that has the potential to undermine the success of the RFS program simply as a result of increasing instability and uncertainty in programmatic obligations.

Several commenters referenced the statutory directive that the EPA "ensure that transportation fuel . . . contains at least the applicable volume" of renewable fuel as evidence that EPA should modify the obligation if it is "hindering growth." As discussed below in Section II., Petitioners only provided theoretical arguments that when evaluated provide no firm basis to conclude that a change in the point of obligation would lead to increased volumes of renewable fuel. In contrast, we continue to believe that the disruption to the program by changing the point of obligation would actually reduce renewable fuel volumes and that long term positive impacts, if any, would be negligible. This belief is supported in part by the fact that the shortfall at this point is exclusively in cellulosic biofuels, and a change to the point of obligation is unlikely to impact cellulosic biofuel production. For this reason, and as further discussed below, we do not believe

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[27] 75 Fed. Reg. 14670.

[28] Ibid.

[29] Valero, in comment, suggested that EPA set an improper burden for petitioners in evaluating the petitions. They stated that they provided sufficient robust evidence to justify a change in the point of obligation. Valero specifically cited to work completed by NERA, SMU, Ron Minsk, Doug Parker, Commander Kirk Lippold, Charles River Associates, and Joe Jobe. EPA has evaluated these analyses and has concluded that they do not provide sufficient justification for a change in the point of obligation. An analysis of each of these reports is presented below in the following sections: II.B., II.C., II.E., II.H., III.B, III.C, III. D, III.G.

that a change in the point of obligation would have the positive effect suggested by Commenters, and we do not believe that the current point of obligation is "hindering growth."

The CAA dictates that the point of obligation should be placed on refineries, importers, or blenders as appropriate. EPA has considered the petitions and comments submitted and finds, for the reasons stated herein, that refiners and importers remain the appropriate parties.

II. The Current Program Structure Appears to Be Working to Achieve the Goals of the RFS Program

Petitioners and some commenters discuss several perceived shortcomings of the RFS program. The petitioners generally attribute these shortcomings, in whole or in part, to the EPA's decision to place the point of obligation on the refiners and importers of gasoline and diesel fuel, rather than parties downstream of the refiners and importers. These claimed shortcomings include, among others, the failure of the RFS program to achieve the statutory volumes of renewable fuel (requiring the use of EPA's waiver authorities) and higher than anticipated RIN prices leading to higher fuel prices for consumers, negative impacts on merchant refiners, and windfall profits for unobligated blenders of renewable fuel. The petitioners conclude that the RIN market, and by extension the RFS program, is not operating as intended, and therefore the EPA should re-visit the point of obligation in the RFS program.

After reviewing the information submitted by the petitioners and commenters, along with additional information gathered by the EPA, we disagree with a number of the assertions and arguments put forward by the petitioners, and do not agree with their policy arguments that changing the point of obligation would enhance the effectiveness of the RFS program to achieve Congress's goals. Evidence suggests that despite the necessary use of EPA's waiver authorities in recent years, the RIN market, and the RFS program as a whole, are generally working to increase supplies of renewable fuel, albeit at a pace slower than Congress envisioned, and that a change in the point of obligation is not likely to enhance the achievement of the program's goals. The RFS program is providing a significant incentive for the continued growth in the production, distribution, and use of renewable fuels in the transportation fuel market in the United States, and changing the point of obligation would not enhance that incentive. With the exception of cellulosic biofuels, renewable fuel production and use in the United States have increased significantly, and are projected to meet or exceed the statutory volumes for non-cellulosic biofuels in 2017. RIN prices themselves have not resulted in appreciably higher transportation fuel prices for consumers or disproportionate harm for merchant refiners.[30] Finally, the record does not support claims that merchant refiners have resorted to the extreme measures suggested by the petitioners, such as decreasing fuel production or exporting the fuel they produce,[31] in an

[30] While RIN prices are expected to impact the price of fuels with relatively greater or lesser renewable content (increasing the price of fuels with low renewable content such as E0 or B0 and decreasing the price of fuels with high renewable content such as E85 or B20), on balance they are not expected to increase the total cost of fuel to consumers.

[31] While gasoline and diesel exports have increased in recent years we believe that these increases are attributable to favorable crude oil and natural gas prices in the United States relative to the rest of the world, rather than an effort to avoid RIN costs. To date EPA has not been provided with evidence that demonstrates that merchant refiners

effort to minimize their RFS obligations. RINs are currently available to meet compliance needs, and we see no reason to indicate that this dynamic will change in the future.[32]

A. RINs are Providing an Incentive for Increasing Renewable Fuel Production, Distribution, and Use

Since the adoption of the current RFS regulations in 2010, the RFS program has provided a significant incentive for growth in the production, distribution, and use of renewable transportation fuels in the United States. While some commenters cited EPA's use of the cellulosic and inadequate domestic supply waiver authorities to reduce the required volumes of renewable fuel in 2014-2016, as well as our May 31, 2016 proposal to use similar authorities with respect to establishing the renewable fuel standards for 2017, as evidence that the RFS program is not working effectively to achieve its stated goals, we believe that the RFS program has been generally successful at achieving these goals. First, EPA did not rely on the general waiver authority under a finding of inadequate domestic supply in the final 2017 rule, meaning that all reductions in the final rule use only the cellulosic waiver authority in 211(o)(7)(D) and are attributable to a shortfall in cellulosic biofuel production.[33] EPA has proposed a similar approach with respect to the 2018 RFS standards.[34] As discussed in more detail in Section III below, we do not believe that changing the point of obligation would result in an increase in the production, distribution, or use of renewable fuels beyond what is already happening based on current market incentives. Based on data collected through the EPA Moderated Transaction System (EMTS),[35] the production and import of renewable transportation fuel in the United States has increased from approximately 7 billion ethanol-equivalent gallons in 2010 to approximately 18.6 billion ethanol-equivalent gallons in 2016, the most recent year for which complete data are available. This represents an increase of over 165% in just six years. Importantly, EPA found no basis for reductions to the advanced and total renewable fuel requirements in 2017 beyond the reductions made under the cellulosic waiver authority due to the projected shortfall in cellulosic biofuel production relative to the statutory volume for 2017. While there are many factors that have contributed to the growth of renewable transportation fuel production and imports in the United States in recent years, including federal and state tax credits for certain types of renewable fuels and federal grants and loan guarantees for advanced biofuel

favorably situated to export fuel from the U.S. have increased exports as a result of any burden associated with the RFS program. We note that despite these higher export volumes, the supply of gasoline and diesel to the United States has not changed (see Section II.D below).

[32] Based on the compliance information submitted by obligated parties for the 2016 compliance year, EPA calculated that there were over 2 billion 2016 RINs available for use in 2017 (see *Carryover RIN Bank Calculations for 2018 NPRM*). Such carryover RINs are available to obligated parties for compliance purposes, effectively supplementing the volume of RINs associated with renewable fuel production during the compliance year.

[33] Renewable Fuel Standard Program: Standards for 2017 and Biomass-Based Diesel Volume for 2018. 81 FR 8946 (December 12, 2016).

[34] Proposed Rule: Renewable Fuel Standard Program: Standards for 2018 and Biomass-Based Diesel Volume for 2019. 82 FR 34206 (July 21, 2017).

[35] RIN generation data are available publicly at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/public-data-renewable-fuel-standard.

production facilities, many stakeholders have regularly cited the RFS program as a primary reason for making investments in both the production and distribution of renewable fuels.[36]

Despite these successes, in recent years the EPA has exercised the statutory waiver authorities to reduce the renewable fuel volumes from those specified in the statute, largely due to the shortfall in cellulosic biofuel production.[37] While the EPA relied on the use of the general waiver authority in 2014-2016, reductions in the 2017 final rule and proposed 2018 rule were made using only the cellulosic waiver authority. Reductions using the cellulosic waiver authority in 2017, and those proposed for 2018, can be attributed to lower production of cellulosic biofuels than envisioned by Congress resulting from challenges experienced with the development and commercialization of cellulosic biofuel production technologies. The projected production and use of non-cellulosic renewable transportation fuels in 2017 and again in 2018 meets or exceeds the volume envisioned by Congress in EISA.[38] Similarly, required biodiesel volumes for 2017 are 100% greater than the statutory prescribed minimum volume, and for 2018 the required volume is 110% greater than the statutory minimum.[39] The petitioners generally focused on the limitations to the distribution and use of renewable fuels, claiming that changing the point of obligation would address these limitations and allow for greater volumes of renewable fuels to be used. We note, however, that these issues were not the basis for reducing the RFS standards in 2017, nor for the proposed reductions in 2018. In the rule establishing the renewable volume obligations for 2017, and again in our proposed rule for 2018, the EPA determined that the supply of conventional biofuel is sufficient to meet the implied statutory target of 15 billion gallons. We also found that the supply of non-cellulosic advanced biofuels was sufficient to meet or exceed the implied statutory requirements for these fuels.[40] As discussed further below, the primary factor limiting the production of cellulosic biofuels, including cellulosic ethanol, is the slower than expected development and commercialization of technologies that can reliably and economically produce these fuels.

Some commenters suggested that changing the point of obligation would provide benefits to the cellulosic biofuels industry, whereas other comments agreed with EPA's proposed assessment that changing the point of obligation would not positively impact the cellulosic biofuel industry.

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[36] For example, see comments on the proposed RFS standards for 2017 from the National Biodiesel Board, EPA-HQ-OAR-2016-0004-2904; and Dana Gustafson of Marquis Energy, EPA-HQ-OAR-2016-0004-3498; and a Letter from RaceTrac to Administrator McCarthy, received August 17, 2016.

[37] For a full discussion of EPA's waiver authorities see the preamble to the Final Rule establishing the 2014-2016 RFS standards (80 FR 77420, Dec. 14, 2015).

[38] The statutory volumes for total renewable fuel, advanced biofuel, and cellulosic biofuel in 2017 are 26.0, 11.0, and 7 billion gallons respectively. Therefore, the implied statutory targets for conventional biofuel (the difference between the required volumes of total renewable fuel and advanced biofuel) and non-cellulosic advanced biofuels (the difference between the statutory volumes of advanced biofuel and cellulosic biofuel) are 15.0 billion gallons and 4 billion gallons respectively. The volumes proposed by EPA in our July 2017 proposed rule for 2018 for total renewable fuel, advanced biofuel, and cellulosic biofuel are 19.24, 4.24 and 0.238 billion gallons respectively, with an implied volume of 15.0 billion gallons of conventional biofuel and 4 billion gallons of non-cellulosic advanced biofuel.

[39] Compare CAA 211(o)(2)(B)(v) (1 billion gallon minimum) with the required volumes of 2.0 and 2.1 billion gallons of biomass-based diesel in 2017 and proposed in 2018 respectively.

[40] EPA calculates the implied statutory target for non-cellulosic advanced biofuels by subtracting the statutory volume for cellulosic biofuel from the statutory volume for advanced biofuels for each year.

These comments are discussed in more detail in Section III.F below. However, overall the EPA does not find the arguments for moving the point of obligation in an effort to support the cellulosic biofuel industry convincing. The proposed cellulosic biofuel volume for 2018 is just 3.4% of the statutory volume (i.e., 238 million ethanol-equivalent gallons expected production compared to a statutory volume of 7 billion gallons). Furthermore, the vast majority of the cellulosic biofuel currently produced is biogas rather than liquid cellulosic biofuels. The RFS program, operating under the existing regulations, has been demonstrably effective at making significant progress towards achieving the statutory goals, and in some cases exceeding these goals. The challenges to further growth in the commercial scale production of cellulosic biofuels and the infrastructure necessary to facilitate additional biofuel use, particularly liquid cellulosic biofuels, are not related to the point of obligation under the RFS program, but rather are the result of research, development, and production challenges described in detail in the final rules establishing the standards for 2014-2017 and in the proposed rule to establish standards for 2018.[41] Beyond 2018, 90% of the growth in the statutory RFS volumes is intended to be cellulosic biofuel, with the remainder of the growth coming from non-cellulosic advanced biofuels. Because the statutory design of the RFS program provides limited incentives to obligated parties to invest in the development of cellulosic biofuels (since the statute requires that the cellulosic biofuel volume be set equal to the volume projected to be produced in any given year if this volume is lower than the statutory volume, and also allows the use of cellulosic waiver credits rather than RINs in years with such a reduction), it is unlikely that changing the point of obligation as requested by the petitioners would result in increased investment in cellulosic biofuels by the obligated parties under their proposals. As discussed further in Section III.F, and based on evidence presented by petitioners, and the information before the agency at this time, changing the point of obligation of the RFS program is unlikely to address the significant challenges associated with the commercialization of cellulosic biofuel, as these challenges are associated with the economic production of cellulosic biofuels at commercial scale rather than the distribution and use of cellulosic biofuels, and would not be expected to benefit the production, distribution, and use of non-cellulosic transportation fuel in the United States, as detailed further below.[42]

B. Current RIN Prices Are Not Indicative of a Dysfunctional RIN Market

One of the issues cited by the petitioners as evidence that the RIN market, and more generally the existing RFS regulations, are not operating as intended is the current price of RINs, which some petitioners have characterized as being indicative of a dysfunctional RIN market.[43] As discussed in a memorandum prepared in support of the proposed RFS annual standards for 2014-

[41] 80 FR 77420 (Dec., 14, 2015), 81 FR 89746 (December 12, 2016) and 82 FR 34206 (July 21, 2017).
[42] As discussed in more detail in Section III.C below, changing the point of obligation is also not expected to significantly impact the market dynamics currently limiting the distribution and use of E85.
[4343] Some commenters suggested that when described in RFS1 and RFS2, RINs were a compliance mechanism only, and not described as a means to effect change in the marketplace. EPA notes that while RINs were designed to provide flexibilities, as the costs associated with increasing renewable fuels in the marketplace has increased, it is logical for RIN prices to increase as well. While at the time the RIN system was created, and the standards were essentially non-binding, RINs played solely a compliance role, but that naturally changed as the standards became more difficult to meet.

2016, the EPA does not believe that the D6 RIN prices[44] observed in recent years are indicative of a dysfunctional RIN market.[45] Rather, there are structural reasons why D6 RIN prices increased. In 2013 the required volumes under EPA's RFS standards exceeded levels that could met via the relatively simple blending of 10% ethanol into gasoline (in addition to the blending of other biofuels such as biodiesel). Increased demand for RINs (due to higher standards), and the comparative difficulty of increasing the supply of RINs through the blending of ethanol at levels *beyond* 10% (or alternatively the purchase of more expensive non-ethanol renewable fuels) drove D6 RIN prices higher. Rather than reflecting a dysfunctional RIN market, higher RIN prices simply reflect the increasing cost of supplying additional renewable fuels to the marketplace through higher level ethanol blends and/or non-ethanol renewable fuels along with the increasing demand for RINs that results from higher RFS standards.[46] In other words, higher RIN prices reflect the greater degree of difficulty (and cost) of getting ever-greater volumes of renewable fuel into the transportation fuel pool – the explicit goal or the RFS program.[47]

EPA does not believe that changing the point of obligation would significantly impact the economics of selling E85 or non-ethanol renewable fuels, nor would it significantly impact the supply of available RINs (for reasons discussed below). We therefore do not believe that changing the point of obligation would be likely to result in lower D6 RIN prices than would be expected to occur with the existing point of obligation, nor would such a change result in D6 RIN prices comparable to those observed in 2012 or earlier. The price of RINs will continue to vary in the marketplace in response to a variety of factors.

Several commenters disputed the EPA's statement in the proposed denial of petitions seeking a change in the RFS point of obligation that the observed RIN prices were not indicative of a dysfunctional RIN market. For example, one petitioner submitted a paper alleging significant friction in the RIN market related to the current point of obligation.[48] This paper cites several factors they claim are the sources of high friction in the RIN market: high RIN transaction costs (indicated by high bid-ask spreads), high RIN price volatility (which may be a sign of an illiquid market), poor availability of information on RIN prices, differing levels of access to renewable fuels and/or markets for renewable fuel blends among obligated parties, and the potential for RIN market manipulation.

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[44] Renewable fuel producers generate different types of RINs, depending on a number of factors including the feedstocks and production processes they use to produce renewable fuels, the type of fuel they produce, and the GHG reductions for these fuels relative to the gasoline and diesel fuel they replace. D6 RINs are generated for conventional biofuel, the vast majority of which is corn ethanol, with some additional D6 RINs being generated for biodiesel from grandfathered facilities and other fuels. Prior to 2013, D6 RIN prices were generally less than 5 cents per RIN. D6 RIN prices rose significantly in 2013, and have remained higher than the prices observed prior to 2013.

[45] See "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA, May 14, 2015, and Letter from API to EPA Administrator McCarthy, August 18, 2016.

[46] Uncertainty, whether related to the level of the RFS standards for any given year or the RFS program as a whole, can further serve to increase the volatility of RIN prices in the market. Some volatility may be inevitable, but increased volatility could be one outcome of changing the point of obligation.

[47] We note that RIN prices are influenced by a variety of factors, including underlying commodity market prices such as corn, ethanol, oil, and gasoline prices. Another factor influencing their price, as described, is the level of the standard and the ease with which higher-level ethanol blends can be produced and used in the market.

[48] Charles River Associates *RINs Market Frictions and the RFS Point of Obligation*, February 2017.

After reviewing this paper, the EPA has concluded that a number of the claims made by the authors are not well supported by the data presented, while other issues highlighted by the authors would be unlikely to be significantly impacted by a change in the point of obligation. The authors present no data to support their argument that RIN transaction costs are high, nor do they present a compelling argument as to why changing the point of obligation would be expected to lower transaction costs. Instead, the commenter simply suggests that the historical volatility of RIN prices is evidence of the high transaction costs and the relative thinness of the RIN markets.[49] While the EPA does not have access to data on RIN transaction costs we have no reason to suspect that they are unreasonably high. Data published by EPA on our public website refutes the suggestion that there is thinness in the RIN market. For the 2014 compliance year, the most recent year for which RIN trade data are publicly available, there were over 50 billion RIN transactions.[50] We believe that the price volatility observed in the RIN market is the result of a number of factors including volatility in underlying commodity pricing, the statutory design of the RFS program, which requires RVOs to be adjusted annually, uncertainty related to legal challenges to the annual volume obligations, and the challenges associated with increasing the consumption of renewable fuel volumes beyond the E10 blendwall. The EPA also disputes that there is poor availability of information on RIN pricing. The EPA is aware of at least two subscription services (Oil Price Information Service and Argus) and one free price report (Progressive Fuels Limited) that report daily RIN price information, including the bid/ask prices and in the case of Argus the RIN trade volumes. Other issues raised in this report, such as the relative inelasticity of the supply of RINs due to the very small markets for E15 and E85, the contractual relationship between refiners and branded stations, and the lack of availability of RIN holding and trade information due to CBI constraints are not expected to be impacted by a change in the point of obligation in the RFS program.[51]

One petitioner also implies that higher RIN prices lead to higher fuel prices for consumers.[52] When D6 RIN prices first rose substantially in 2013, attention turned to whether and how such RIN price increases affect consumer fuel prices. The EPA assessed this issue using available data and concluded that while increasing RFS standards may increase transportation fuel prices if renewable fuels are more expensive than the petroleum fuels they replace on an energy-equivalent basis, *RIN prices themselves* were not expected to have a significant impact on retail fuel prices.[53] External, non-EPA assessments similarly concluded that increased RIN prices had

[49] A thin market is one in which the trading volume is relatively low and/or there are a relatively low number of buyers and sellers.
[50] See Annual RIN Sales/Holdings Summary on EPA public website: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-rin-salesholdings-summary.
[51] See Section III.B – III.D for a further discussion of the anticipated impacts of changing the point of obligation on the sales of renewable fuels and renewable fuel blends. The contractual relationships between the refiners and retail stations, which can include fuel purchase restrictions, sales volume requirements, requirements on the number of grades of gasoline which must be offered, etc. predate the RFS requirements and are therefore unlikely to change substantively if the point of obligation is changed. Finally, RIN holding and trade information is generally claimed as confidential business information (CBI), and this would likely be the case regardless of whether the obligated parties are refiners and importers or if they are "position holders" or blenders.
[52] Valero Petition for Rulemaking, June 13, 2016. Page 18.
[53] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA. May 14, 2015.

not had a significant impact on retail gasoline (E10) prices.[54] When RIN prices rise, the market price of the petroleum blendstocks produced by refineries also rise to cover the increased RIN costs, in much the same way as they would rise in response to higher crude oil prices. The effective price of renewable fuels (the price of the renewable fuel with attached RIN minus the RIN price), however, *decreases* as RIN prices increase. When renewable fuels are blended into petroleum fuels these two price impacts generally offset one another for fuel blends such as E10 with a renewable content approximately equal to the required renewable fuel percentage standard. Higher RIN prices also generally result in higher prices for fuels with lower renewable content (such as E0 or petroleum diesel) and lower prices for fuels with higher renewable content (such as E85 or B20). The cost of the RIN therefore serves as a cross-subsidy, reducing the price of renewable fuels and increasing the price of petroleum based fuels in transportation fuel blends, thus incentivizing increased blending of renewable fuels into the transportation fuel pool. In this way the RINs also help provide a price signal to consumers to help achieve the Congressional goals of greater renewable fuel production and use. Fuels with higher renewable content are relatively cheaper to consumers than they would be absent high RIN prices, while fuels with lower renewable content are relatively more expensive when RIN prices are high.[55] The higher the RIN prices are, the more significant the potential price discounts for fuels with higher renewable content. This retail price discount for fuels with a relatively high renewable content is enabled by higher prices for fuel blends with little or no renewable fuel content.

C. The Current Regulations do not Appear to Disproportionately Impact Merchant Refiners or Provide Windfall Profits for Unobligated Blenders

In requesting that the EPA change the point of obligation petitioners claim that the current point of obligation negatively impacts refiners that do not blend renewable fuels and/or do not sell fuel at the rack. They generally claim that this negative impact is due to these refiners incurring a high cost for RINs purchased to comply with their RFS obligations. They contrast this with what they say is the situation facing integrated refiners, whom they state are acquiring RINs for free by blending renewable fuels. Petitioners also argue that unobligated fuel blenders (such as large retail fuel chains or fuel distributers and refiners that market more fuel at the rack than they refine or import) are selling excess RINs and generating windfall profits. Several other parties have submitted documents to the EPA disputing these claims.[56]

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[54] Knittel, Christopher R., Ben S. Meiselman, and James H. Stock. The Passthrough of RIN Prices to Wholesale and Retail Fuels Under the Renewable Fuel Standard. Working Paper 21343. NBER Working Paper Series. Available online <http://www.nber.org/papers/w21343.pdf>.

[55] Even when RIN prices are relatively high fuels with high renewable content may not be cheaper than fuels with lower renewable content on an energy-equivalent basis. For example, despite relatively higher RIN prices since 2013, the national average price discount for E85 relative to E10 has never reached or exceeded 22% (the price discount needed for achieve parity between E85 and E10 on an energy equivalent basis). See also "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects," Dallas Burkholder, Office of Transportation and Air Quality, U.S. EPA, May 2015. and "An Assessment of the Impact of RIN Prices on the Retail Price of E85," Dallas Burkholder, Office of Transportation and Air Quality, U.S. EPA, November 2015.

[56] See Letter from RaceTrac to Administrator McCarthy, August 17, 2016; Letter from QuikTrip to Administrator McCarthy, August 17, 2016; Presentation from Murphy USA to EPA, August 16, 2016.

We have assessed the data available on this issue and believe that the data do not support the petitioners' arguments. We believe that merchant refiners are generally not uniquely adversely impacted (relative to integrated refiners). Our reasons for not believing that merchant refiners are uniquely impacted by the RFS program are summarized below.[57]

To understand why this is the case, we must consider the fundamental argument about cost disparities that petitioners and merchant refiners present to the EPA. Several merchant refiners argue that due to their position in the market as refiners with little or no blending and/or sales of fuel at the rack, their sole RFS compliance option is to purchase unattached RINs (that is, RINs that have already been separated from renewable fuel). Merchant refiners typically purchase these RINs on the market and retire them for compliance purposes; a large merchant refiner can spend considerable sums to purchase these RINs, and they typically point to these sums as an expenditure that represents a net cost to the company.[58] Some merchant refiners then argue that their integrated refiner competitors, by contrast, do not face such costs, arguing that integrated refiners acquire RINs "for free" when they purchase renewable fuel with an attached RIN. They argue that this dynamic results in a fundamental inequity between two types of RFS obligated parties: those that pay large sums to acquire RINs on the open market, and those that obtain RINs "for free." Moving the point of obligation, petitioners argue, would help address this inequity. To understand why this argument is flawed, it is helpful to examine the underlying market dynamics in more detail.

It is indeed the case that for the RVO associated with the production volumes they do not market, merchant refiners generally acquire the RINs necessary for compliance with their RFS obligations by purchasing separated RINs, rather than purchasing renewable fuel with assigned RINs. Because of this, merchant refiners are therefore able to directly track the costs associated with acquiring the RINs they need for compliance and cite these costs in their financial and accounting statements. When RIN prices are relatively high these apparent costs can be significant, especially for merchant refiners that refine large volumes of obligated fuels.

Less obviously apparent, however, is *the impact of the RFS program on the market price for the petroleum blendstocks that merchant refiners sell*. In addition, as discussed further below, all refiners and importers of gasoline and diesel fuel destined for the domestic market incur costs to comply with RFS obligations. This is true whether the refiners and importers acquire RINs by blending renewable fuels (in which case they realize a cost when they sell blended fuels for a lower price than the weighted average of the petroleum blendstocks and renewable fuels that comprise the blended fuel) or purchasing separated RINs – meaning no fundamental inequity exists.[59] Moreover, because all refiners and importers have RFS obligations in proportion to the fuels they produce or import, they all have similar per gallon costs of compliance related to the RFS program, and they all seek to recover those costs through the pricing of their products, whether that product is blended with renewable fuel and sold at a terminal or is unblended

[57] For further detail see "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA. May 14, 2015.
[58] For example, see comments from CVR Energy on the 2017 RFS standards proposed rule, EPA-HQ-OAR-2016-0004-0213.
[59] The issue of whether or not integrated refiners and other unobligated blenders acquire RINs "for free" or at a reduced cost is addressed more fully later in this section.

petroleum blendstocks sold at the refinery gate. Stated another way: merchant refiners can indeed expend significant funds to purchase RINs needed to demonstrate compliance with the RFS program, but the cost is offset by a corresponding increase in the market price of the fuel they sell that is attributable to the RFS obligations. The market price they receive for the gasoline and diesel fuel they sell reflects the cost of RINs. While high RIN prices increase the market price of petroleum blendstocks, they generally do not increase the market price of fuels blended with renewable fuels, as the blenders use the value of the RIN to reduce the price of the blended fuels. The same dynamic applies to all gasoline blendstocks and diesel fuel produced by both merchant and integrated refiners alike. Further, many merchant refiners blend a portion of the gasoline and diesel they produce with renewable fuels and directly market this fuel (while selling the majority to other parties for marketing), while many integrated refiners sell a portion of the gasoline and diesel they produce as unblended blendstocks to other fuel marketers. There are not two prices in the market for petroleum fuels based on whether or not they are intended to be marketed directly to consumers or sold to a downstream marketer, but rather separate prices for petroleum blendstocks and blended fuels.

The EPA also examined the available data to assess whether or not obligated parties that acquire RINs by purchasing separated RINs, rather than blending renewable fuels, are able to recover the cost of these RINs in the price of the petroleum blendstocks they sell. In their petition, Valero acknowledges this ability for refiners to recover the cost of acquiring RINs through higher prices for gasoline and diesel they produce than would be the case with lower RIN prices.[60] Empirical data also support this argument. Data clearly show higher market prices for RFS-obligated fuels (gasoline and diesel blendstocks sold for use in the United States) when compared to those of unobligated fuels that are very similar (such as gasoline and diesel sold for export, or heating oil and jet fuel).[61] Before accounting for any potential RIN price impacts, one would expect obligated and unobligated fuels to have very similar market prices because of their very similar fuel properties. Gasoline is nearly identical whether used domestically or sold for export, and heating oil and diesel are also very similar chemically. However, in recent years, as RIN prices have become elevated, data show a gap opening up between the price of domestic gasoline and exported gasoline, and between the price of diesel and heating oil. The price of the obligated fuels is higher and the gap corresponds, for the most part, with RIN prices. Obligated parties – whether they are merchant refiners or integrated—are charging more for domestic gasoline and diesel to ensure they recoup the costs associated with RIN prices. So while a merchant refiner is directly paying for the RINs they buy on the market, they are passing that cost along in the form of higher wholesale gasoline and diesel prices.

Several commenters submitted assessments of the fuels market disputing the EPA's claim that merchant refiners were generally able to recover the cost of RINs through the higher prices for the products they sell. Some of these studies referred to this as an inability to "pass-through" the cost of the RFS program to consumers. After careful review of the information submitted, the EPA does not find these assessments convincing. All obligated parties, including merchant

[60] Valero Petition for Rulemaking, June 13, 2016. Page 18.
[61] See "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA. May 14, 2015 and Letter from QuikTrip to Administrator McCarthy, August 17, 2016.

refiners, are generally able to recover the cost of the RINs they need for compliance with the RFS obligations through the cost of the gasoline and diesel fuel they produce.

Some of these assessments submitted or referenced in comments simply assumed that RIN costs were not recovered by merchant refiners and/or were not experienced by integrated refiners or other parties that acquire RINs by blending.[62] As discussed above, these assumptions are unfounded, as they ignore the complexities of the fuels market and the various ways costs are recovered and/or experienced as a result of the RFS obligations. Other assessments attempt to examine blender margins as a means of determining whether or not the cost of RINs are recovered by merchant refiners, or alternatively if the value of the RINs are passed on to consumers or withheld by blenders.[63] While examining correlations between RIN prices and estimated blender margins may provide some level of indication about the ability for the blenders to withhold some portion of the RIN value, we do not believe these assessments can be used to draw definitive conclusions on the degree of RIN passthrough in the marketplace, as there are many other factors that impact blender margins other than RIN prices that were changing simultaneously and were not addressed in the study.[64] Finally, one commenter presented an argument that integrated refiners would have an incentive to attempt to prevent the value of the RIN from being reflected in the wholesale prices of gasoline and diesel.[65] This comment effectively argued that parties that purchase bulk quantities of gasoline blendstock (such as unobligated blenders or refiners that market more fuel than they refine) would be incentivized to keep the purchase prices of these products low. It does not, however, address why the parties would be effective in negotiating sales prices that do not reflect the value of the RIN.[66] The

[62] See, for example, Baker & O'Brien *Impact of RINs on Merchant and Integrated Refiners*, October 28, 2016 and comments by CVR Energy (EPA-HQ-OAR-2016-0544-0396). We also note that the calculations cited by CVR.Energy in the DOE Study at B-5 not only simply assume that refiners that purchase separated RINs do not recover the cost of the RINs, but also erroneously assume that refiners that blend ethanol into gasoline retail the full value of VEETC tax credit, which expired at the end of 2011. The value of this tax credit is responsible for the majority of the advantages claimed by the commenter for refiners that blend ethanol vs. those that buy RINs to meet their RVO.

[63] See, for example, Charles River Associates *Evaluating the Response of Blender Margins to RIN Price Changes*, February 2017.

[64] For example, the local market demand vs. supply (whether the local market is short or long on gasoline) can have a significant impact on blender margins. We further note that this study did not consider data prior to 2013, which would have allowed for consideration in the variability of blender margins during a time when RIN prices were very low.

[65] See Comment from Bob Neufeld, Neufeld Consulting LLC, EPA-HQ-OAR-2016-0544-0272.

[66] In his comments Mr. Neufeld effectively assumes that parties that purchase gasoline and diesel at wholesale will be able to set the market price at a level that does not reflect RIN costs. EPA believes this is highly unlikely. The only evidence Mr. Neufeld presents to support his arguments are several calculations contained in a powerpoint presentation (also submitted in his comments on the proposed denial). We believe there are several fundamental flaws in the calculations presented in this document. First, in his calculations Mr. Neufeld uses E10 and BOB prices from Mitchell, South Dakota but ethanol prices from Chicago. This is highly problematic as the relevant ethanol price for these calculations is the price in Mitchell, South Dakota, which may be higher than the price in Chicago. This is particularly important when the relevant margins are only a few cents. Mr. Neufeld also ignores any blending costs that would be realized by parties purchasing ethanol and BOB separately but not by parties purchasing blended E10. In comparing blending margins between marketers/retailers and obligated refiners he assumes that integrated refiners receive the market price for BOBs, which is not the case if they are selling blended fuels (rather than BOBs) and retaining the RINs for compliance purposes. Finally, we note that any assessment focusing on a single location may not adequately represent the full economics of a national level program.

wholesale price of gasoline and diesel is determined by the relative supply and demand of these products, and the supply curves for refined products reflects all relevant costs, including crude oil costs, labor and capital costs, and RFS compliance costs.

The EPA also received numerous comments from a variety of stakeholders, including refiners, retailers, and academic researchers supporting our assessment that merchant refiners generally recover the cost of the RINs they purchase through higher prices for the petroleum based fuels they produce.[67] Along with the assessments cited in the discussion above, we believe two related papers by Knittel et al and a paper prepared by Argus Consulting Services, all of which were submitted in comments to our proposed denial, present compelling evidence that merchant refiners are able to recover the cost of RINs.[68] All of these papers examined the wholesale prices of petroleum fuels that are very similar with the exception of whether or not the producers of these fuels incurred an RFS obligation (for example, diesel fuel and jet fuel prices from the U.S. gulf coast). Unlike other studies that examined indirect indicators that are susceptible to many factors outside of the RFS program such as blender margins or crude oil crack spreads, this methodology allows the authors to directly assess the impact of RIN prices on fuels that are very similar both physically and chemically.[69] The authors of these papers concluded that the RIN cost was generally included in the sales prices of obligated fuels. Knittel et al further found that the RIN pass through, or the ability of the merchant refiners to recover the cost of RINs was complete (not statistically different than 100%) and occurred quickly (within 2 business days).[70]

Multiple commenters critiqued methods used by Knittel et al in these papers.[71] These critiques generally focused on 3 issues: the removal of Brent crude based spreads from the assessment, the addition of a NYH CBOB – Rotterdam EBOB spread, and the pooling approach used by the authors. The removal of the Brent crude based spreads improves rather than diminishes the assessment presented by Knittel et al. We believe the impact of the RIN price on the wholesale price of refined products is most clearly seen by comparing pairs of refined products rather than comparing crude prices to refined product prices, as many compounding factors can and do influence the price relationship between crude oil and refined products. Further, while there may be concerns related to the appropriateness of the decisions by the authors to include an additional refined product price spread and pool the results of the various comparisons, EPA does not believe these decisions had a significant impact on the conclusions of the paper. Even if the EPA excludes consideration of the additional refined product pair and assesses the five original

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[67] For example, see comments submitted by Marcia Pica Karp, Chevron, EPA-HQ-OAR-2016-0544-0209; David Masuret, Cumberland Farms, EPA-HQ-OAR-2016-0544-0160; C.R. Knittel et al. EPA-HQ-OAR-2016-0544-0280.
[68] Knittel, Christopher R., Meiselman, Ben S., and Stock, James H. *The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard*, November 2016.; Knittel, Christopher R., Meiselman, Ben S., and Stock, James H. *The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard: Analysis of Post-March 2015 Data*. November 23, 2016.; Argus Consulting Services. *Do Obligated Parties Include RIN costs in Product Prices?* February 2017.
[69] Argus Consulting Services also examined the average price ratio between RBOB and ULSD to crude prior to 2013 and between 2013 and 2016 which, while not conclusive on its own, similarly indicated that refiners were reflecting RIN costs in the prices of RBOB and ULSD. Argus also noted that both Argus and Platts include RVO cost considerations in their pricing methodology.
[70] Ibid.
[71] Charles River Associates. *Review of Updated Pass-Through Analysis of Knittel, Meiselman and Stock*. February 2017.

refined product spreads individually rather than together as suggested by commenters critiquing the Knittel et al paper, this paper provides compelling evidence that the RIN price is reflected in the wholesale price of refined products subject to an RFS obligation, and that the RIN cost is therefore generally recovered by obligated parties, including merchant refiners.

In their petition, Valero, while generally acknowledging their efforts to recover RIN costs through higher prices for their petroleum blendstocks,[72] nevertheless claims that the RFS program leaves them at a disadvantage relative to integrated refiners. They argue that while both merchant and integrated refiners receive higher prices for their petroleum blendstocks as a result of the RFS obligations, merchant refiners must use this additional income to purchase RINs for compliance while integrated refiners acquire the RINs they need for compliance "for free" by blending renewable fuels.[73] This argument is illogical as it simply ignores the cost that integrated refiners pay to acquire RINs.

Unlike merchant refiners, integrated refiners generally acquire most of their RINs by purchasing renewable fuel with attached RINs. After blending the renewable fuel with petroleum blendstocks to produce finished transportation fuel, integrated refiners separate the RINs and keep them to demonstrate compliance, or in some cases sell excess RINs to other obligated parties.

While the integrated refiners generally do not purchase separated RINs with an easily-identified price, it is not the case that they acquire these RINs for free.[74] They no more receive the RIN for free than one receives an engine for free when purchasing a car. In examining wholesale prices for gasoline blendstocks, ethanol, and blended E10, EPA found that the listed prices for blended E10 were consistently lower than the price that would be expected based on the selling prices of the component fuels.[75] In other words if we were to ignore the RIN revenue, parties that produce E10 by blending gasoline blendstocks with ethanol would be losing money on every gallon of E10 they produce. A gallon of E10 is generally produced by blending 0.9 gallons of gasoline blendstock (usually CBOB or RBOB) with 0.1 gallons of ethanol. The listed price for E10, however, was lower than the price of 0.9 gallons of gasoline blendstock plus 0.1 gallons of ethanol.[76] Thus, integrated refiners are selling blended E10 for a lower price than they could receive for the component fuels (petroleum blendstock and ethanol) to acquire the RINs that can be separated and retained if they sell blended E10. Integrated refiners therefore experience the cost of acquiring RINs when they sell blended fuels for a lower price than the blend components, while merchant refiners experience RIN costs when they purchase separated RINs. In each case there is a cost to the refiners to acquire RINs, and in each case they recover this cost through higher petroleum blendstock prices. In a presentation to the EPA, Murphy USA discussed this

[72] For example, see Valero Petition for Rulemaking, June 13, 2016. Page 18. In more recent communications with EPA Valero has questioned the ability for merchant refiners to recover the full cost of the RIN through the price of their petroleum blendstocks under current market conditions.
[73] For example, see Valero Petition for Rulemaking, June 13, 2016. Page 16.
[74] Parties that acquire RINs through blending have affirmed that they do not receive RINs for free. For example, see testimony from Chris Vergona of Musket Corporation on the proposed 2018 RFS annual rule.
[75] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA. May 14, 2015.
[76] Ibid

market reality, stating that the RIN prices supported a negative "spot-to-rack margin."[77] They are purchasing petroleum blendstocks from refiners for a higher price than they can recover for this product when sold at the rack as blended E10 but maintaining profitability through RIN sales. This observed market practice supports the findings by the EPA and other parties that despite the higher prices of petroleum blendstocks resulting from higher RIN prices, the costs of transportation fuel to consumers have not increased as Valero has claimed.[78]

While the EPA continues to believe that refiners, including merchant refiners, are generally able to recover the cost of RINs through the prices they receive for the petroleum blendstocks they sell, we also acknowledge that there are many diverse factors that impact each individual refiner's profitability and their ability to recover their full cost of production (including crude oil costs, labor costs, capital costs, regulatory and compliance costs, etc.). These factors include, but are not limited to, the refinery's location, their access to various types of crude oil, the local demand and competition for refined products. In recent years, a number of factors have led to an oversupply of refined gasoline and diesel in the United States. In such a market we would expect significant pressure on refining margins as the supply of refined products outpaces demand and refiners compete with one another to find markets for their products (potentially including exports) and maintain market share. These market conditions are expected to result in reduced profit margins for refiners, and in some cases refiners may struggle to remain profitable.[79] In evaluating whether or not to change the point of obligation, however, it is important to consider whether these challenges are caused by the current point of obligation in the RFS program (rather than more broad market conditions), and whether changing the point of obligation would be expected to address these challenges. Based on the information discussed above, we do not believe the challenges faced by some refiners in the current market are the result of their designation as obligated parties in the RFS program.

The EPA also examined claims made by the petitioners that unobligated blenders were reporting windfall profits by selling RINs. The petitioners primarily supported these claims by referencing the financial statements of companies that acquire RINs by blending renewable fuels and who sell these RINs to obligated parties, but are not obligated parties themselves.[80] EPA does not believe that the information presented by the petitioners substantiates their claims that unobligated blenders are generating windfall profits from RIN sales. First, we note that the fact that companies report income for RIN sales does not indicate that these companies are receiving a windfall from the RFS program. This is equivalent to claiming a company's reported sales are

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[77] See Presentation from Murphy USA to EPA, August 16, 2016.

[78] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA. May 14, 2015 and Knittel, Christopher R., Ben S. Meiselman, and James H. Stock. The Passthrough of RIN Prices to Wholesale and Retail Fuels Under the Renewable Fuel Standard. Working Paper 21343. NBER Working Paper Series. Available online <http://www.nber.org/papers/w21343.pdf>. While these papers demonstrate that the cost of transportation fuel to consumers does not increase due to higher RIN prices, EPA acknowledges that higher renewable fuel obligations can lead to higher transportation fuel prices for consumers if renewable fuels cost more than the petroleum based fuels they displace.

[79] See *2017 US Refining Forecast: Lean Times* Ahead, Opportune LLP, December 7, 2016. Available online: https://www.lexology.com/library/detail.aspx?g=b7ae9acf-fc7d-466c-92a8-43b9fc005722. In recent years, US refinery profitability has benefited from exporting excess refined products given their favorable economics situations compared to many foreign refiners.

[80] The parties most commonly cited by the petitioners are Murphy USA and Casey's General Stores.

equivalent to their profits, while ignoring their expenses to acquire the good sold. While it is true that for companies such as Murphy USA who sell a significant number of RINs their "revenues are impacted by [their] ability to generate revenues from activities such as blending bulk fuel with ethanol and bio-diesel to capture and subsequently sell Renewable Identification Numbers,"[81] this does not mean that these companies receive a windfall profit from RIN sales. Such an assessment ignores costs that the company realized in order to acquire these RINs, such as lower fuel margins than would have been realized if the party did not blend renewable fuels and any investments in infrastructure that the company has made to enable them to blend renewable fuels and distribute these fuel blends. Statements from Murphy USA cited in the AFPM petition to support AFPM's claim that non-obligated blenders are realizing windfall profits from RIN sales in fact support EPA's views of the market. In a recent earnings call, the President of Murphy USA stated "if you add the combination of the gross margin from product supply and wholesale and the RINs and divide over the total retail gallons sold, you actually see a fairly consistent incremental $0.025 per gallon over the past two years."[82] In other words, overall fuel supply margins (including RIN sales) have been relatively consistent despite the significant increase in RIN prices. This supports the EPA's view that RIN costs and revenues must be viewed in combination with other product supply and wholesaling margins. The EPA received many comments from blenders indicating that the RIN value is used to offset the cost of blending, and that the value of the RIN is used to pass savings onto consumers.[83] Additionally, many blenders indicated that they purchase fuel above the rack only some of the time, and instead chose to purchase blended fuel below the rack at times, based on factors such as geography, store density, suppliers, relationships with terminals and infrastructure.[84]

The EPA recognizes that there are many factors that affect the profitability of participants in the fuels market, and disagrees that the available information supports a conclusion that RIN revenues are leading to windfall profits. In 2014 and 2015 Murphy USA reported RIN sale revenues of $93 million and $118 million respectively. If this income represented windfall profits, we would expect that the net income of Murphy USA would be approximately $100 million per year higher than it was prior to the significant increase in RIN prices in 2013. In fact, while Murphy USA's profits in 2014 and 2015 of $244 million and $176 million[85] were significantly higher than in 2012 ($84 million), they were significantly less than net profits in 2011 ($324 million).[86] While we acknowledge that there are many factors that impact the profitability of a company such as Murphy USA in any given year, we nevertheless believe that the data before the Agency does not support the claims by some parties, whether explicit or implicit, that RIN sales represent windfall profits to companies that blend renewable fuels.

[81] Murphy USA, Inc., U.S. SEC Form 10-K for the financial year ended December 31, 2015.
[82] Transcript of Murphy USA First Quarter Earnings Call, Andrew Clyde, President, Murphy USA, Thompson Reuters (Feb. 4, 2016). Citation from AFPM's petition for rulemaking, August 4, 2016. (page 15) .
[83] See, e.g., Comments submitted by Cumberland Farms, EPA-HQ-OAR-2016-0054-0160.; SEI Fuel and 7-Eleven, EPA-HQ-OAR-2016-0054-0133.;
[84] See, e.g., Comments submitted by SEI Fuel and 7-Eleven, EPA-HQ-OAR-2016-0054-0133. Fuel purchased below the rack would not have an RFS obligation even if EPA changed to point of obligation to the "position holders" as the petitioners have requested.
[85] Murphy USA net profit numbers for 2014 and 2015 from Murphy USA, Inc., U.S. SEC Form 10-K for the financial year ended December 31, 2015.
[86] Murphy USA net profit numbers for 2011 and 2012 from Murphy USA, Inc., U.S. SEC Form 10-K for the financial year ended December 31, 2013.

Further, statements from Casey's General Stores and Murphy USA contradict the notion that RIN sales represent windfall profits for unobligated blenders. Murphy USA reported that in the third quarter of 2014 income received from RIN sales offset negative product supply and wholesale margins.[87] This statement is in line with statements from Murphy USA cited above and EPA's view of the market explained in the preceding paragraph, that companies that blend renewable fuels with petroleum blendstocks to produce finished transportation fuel must purchase petroleum blendstocks at a higher price that reflects the cost of the RIN, and sell blended transportation fuel at a lower price that reflects their ability to separate and sell the RINs associated with the renewable fuel, to offer finished fuel at a competitive price. In effect, these parties sell the finished transportation fuel at a loss (or a much smaller margin than would be sustainable in a market without RIN obligations) in order to obtain RINs. In their annual report filed in June 2015, Casey's General Stores directly stated that their general pricing practice is to price to their competition,[88] a practice the EPA has repeatedly stated we expect is the general practice in competitive markets. We believe this competitive pricing behavior is incompatible with the windfall profits suggested by the petitioners.

Many commenters addressed the issue of the potential for unobligated blenders to earn windfall profits from RIN sales and the competitive advantages these RIN sales could provide relative to small retailers that do not blend renewable fuels. Many commenters, including several large retailers and unobligated blenders, agreed with the EPA's assessment of the market and affirmed that unobligated blenders are not realizing windfall profits from RIN sales.[89] One commenter provided data from their local market including the prices of ethanol, gasoline blendstocks, RINs, and other costs associated with supplying blended transportation fuel demonstrating that the value of the RIN was indeed reflected in the wholesale price of E10 and was not withheld by the fuel blender.[90] This commenter presented further information demonstrating that despite their status as a largely unobligated blender, the RIN prices had no impact on their retail fuel margins from August 2008 through August 2016.[91]

Other commenters, however, questioned this finding, with several submitting papers or public statements made by representatives of unobligated blenders supporting their views.[92] Two primary references often cited by commenters, which are generally representative of comments received on this issue, are a report on the estimation of the margins of large retailers by Ramon

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[87] *Murphy USA Inc. Reports Third Quarter 2014 Results.* Yahoo! Finance, November 5, 2014. Available online <http://finance.yahoo.com/news/murphy-usa-inc-reports-third-220006760.html>.
[88] Casey's General Stores, Inc., Annual Report (Form 10-K) (June 26, 2015).
[89] For example, see comments from Casey's General Stores, Inc, EPA-HQ-OAR-2016-0544-0268, NATSO EPA-HQ-OAR-2016-0544-0282, SEI Fuels and 7-Eleven, EPA-HQ-OAR-2016-0544-0133, Murphy USA, EPA-HQ-OAR-2016-0544-0372, QuikTrip, EPA-HQ-OAR-2016-0544-0198, and KwikTrip, EPA-HQ-OAR-2016-0544-0105.
[90] See comments from Cumberland Farms, EPA-HQ-OAR-2016-0544-0160. As part of their comment Cumberland Farms also submitted a screen shot of the software they use to calculate and account for E10 fuel costs. The value of the RIN is directly taken into account in their pricing calculations.
[91] Ibid.
[92] For example, see comments from Valero, EPA-HQ-OAR-2016-0544-0274, Small Retailer Coalition, EPA-HQ-OAR-2016-0544-0344, Buffalo Services, Inc., EPA-HQ-OAR-2016-0544-0184, Friendly Mart Food Stores, EPA-HQ-OAR-2016-0544-0387.

Benavides and a paper authored by Dr. Weinstein on the consequences of RIN trading for small retailers.[93] The paper by Mr. Benavides attempts to estimate retail margins for two large retailers (Pilot/Flying J and Loves) compared to reported national averages. After finding higher than average retail margins, Mr. Benavides attributes these higher margins to the ability to retain the value of the RIN when blending renewable fuels. This paper, however, contains several methodological flaws. As noted in comments by the National Association of Truck Stop Owners (NATSO)[94] the paper considers only data from a single day rather than an extended time period, used broad market data rather than data specific to the companies it assesses, does not consider costs to transport renewable fuels to retail outlets, simply assumes that retailers retain 100% of the value of the RIN and any tax credits associated with the renewable fuel, and does not account for the actual prices paid by their customers (which often include significant discounts from posted prices). The paper also incorrectly assumes a uniform, nationwide price for renewable fuels. Finally, even if the higher margins suggested by this paper are accurate (which appears highly unlikely), the paper makes no attempt to attribute this higher margin to the value of the RINs versus other factors that may contribute to higher margins of the companies assessed relative to the national average such as these parties' ability to buy fuel in bulk, high fuel sales volumes, etc.

The EPA also reviewed the paper prepared by Dr. Weinstein for the Small Retailer Coalition on the unintended consequences of the RFS program for small fuel retailers.[95] In concluding that the current point of obligation could disadvantage small retailers (relative to large retailers with the ability to blend renewable fuels and separate RINs) Dr. Weinstein relied on two primary sources; the paper by Mr. Benavides discussed above and statements by several large companies that own retail fuel stations and blend renewable fuels. Generally, Dr. Weinstein highlights income associated with RIN sales and statements that access to RINs and RIN revenue advantages these companies relative to their competitors as the basis for his conclusions. However, these statements do not justify Dr. Weinstein's conclusions. First, as discussed above, income from RIN sales is not equivalent to profits from the separation of the RINs, nor is it evidence that these parties can retain all or a significant portion of the value of the RINs. Indeed, as highlighted in the statement by Murphy in their Form 10-Q filed on November 3, 2016 (quoted in Dr. Weinstein's paper) Murphy accepts negative product supply and wholesale margins in order to get access to RINs. The RINs are not "free" to these large retailers, and do not represent windfall profits. Additionally, statements that these companies are advantaged relative to their competitors with respect to their ability to realize additional margin from RINs and RIN sales do not suggest windfall profits as a result of the current point of obligation in the RFS program. There are many reasons these companies could be advantaged relative to their competitors with respect to their ability to realize profits from RINs and RIN sales such as advantageous long term contracts for renewable fuels, access to renewable fuels with higher value RINs (such as advanced or cellulosic biofuels, as alluded to by Couche-Tard's CFO Claude Tessier), better retail markets for higher level blends of renewable fuels, and the ability to hold RINs in an effort

[93] Benavides, Ramon M. *Renewable Fuel Incentives: Estimation of Large Retailers' Margins* and Weinstein, Dr. Bernard L. *Renewable Identification Numbers (RINs) Trading Under the Renewable Fuels Program: Continued Unintended Consequences for Small Fuel Retailers Updated Report*. February 2017.
[94] See comments from NATSO, EPA-HQ-OAR-2016-0544-0282.
[95] Weinstein, Dr. Bernard L. *Renewable Identification Numbers (RINs) Trading Under the Renewable Fuels Program: Continued Unintended Consequences for Small Fuel Retailers Updated Report*. February 2017.

to sell when the prices are most favorable.[96] None of these factors are the result of the point of obligation in the RFS program, nor would any of them change if EPA were to change the point of obligation as the petitioners suggest.[97]

After reviewing the comments submitted on our proposed denial of the petitions to change the point of obligation in the RFS program, the EPA reaffirms the position stated in our proposed denial. We do not believe the available data indicates that large retailers or unobligated blenders are realizing windfall profits as the result of their access to RINs. On the other hand, a contrary finding is well supported by the data presented here and the supporting comments submitted by many with direct knowledge and experience on this issue. While we recognize that many small retailers may be facing significant economic hardship, we do not believe this hardship is primarily or even materially caused by the current point of obligation in the RFS program, but rather by a number of broader market factors (see Section II.D for a further discussion of this issue).

D. The Current Regulations Do Not Appear to Negatively Impact Small Retailers

The EPA received comments from the Small Retailers Coalition, an organization created in 2016 representing over 200 owners of gas stations and convenience stores, as well as comments from a number of parties that own and operate retail fuel stations.[98] EPA also received comments from the National Black Caucus of State Legislators echoing many of the concerns raised by the Small Retailers Coalition, contending that independent gasoline retail stations are harmed by the current point of obligation.[99] These comments suggested that the current point of obligation is harming small retailers by allowing their competitors to obtain and sell RINs which allow their competitors to more competitively price their fuels. They contend that their competitors are gaining a $0.10-$0.15 per gallon advantage over small and medium suppliers. Commenters further suggest that this pricing advantage is available to their competitors as a result of their ability to realize windfall profits from RIN sales and that the disparity will likely result in the closure of a large number of the stores owned by single-store owners and medium sized gas stations and convenience stores. According to some commenters, such closures could lead to lower levels of competition among parties that sell gasoline and diesel at the retail level, ultimately leading to higher fuel prices for consumers. Some commenters suggested that because large retailers are realizing such significant profits from RIN sales they have no incentive to invest in infrastructure to expand the availability and use of renewable fuels, and in some cases

[96] See comments from the Small Retailers Coalition, EPA-HQ-OAR-2016-0544-0344.
[97] These advantages are related to the company's ability to acquire renewable fuels at lower prices than their competitors or their ability to sell renewable fuel blends at higher prices than their competitors. To the degree these advantages exist, they are highly unlikely to be impacted by a change in the point of obligation.
[98] For example, see comments from the Small Retailer Coalition, EPA-HQ-OAR-2016-0544-0344; Short Stop, EPA-HQ-OAR-2016-0544-0174; L & L Stores, EPA-HQ-OAR-2016-0544-0426. EPA also received a series of comments from the Petroleum Marketers Association of America (PMAA). Initial comments from PMAA indicated support for maintaining the current point of obligation, however in subsequent correspondence PMAA stated it was taking a neutral position on where the point of obligation should be placed due to growing concerns for unfair competition in the retail market. EPA believes these concerns are adequately addressed in this section.
[99] Comment from National Black Caucus of State Legislators, EPA-HQ-OAR-2016-0544-0166.

large retailers may actively work to restrict the expansion of this infrastructure, since commenters claim expanded infrastructure would reduce RIN prices. In comments, the Small Retailers Coalition suggested EPA should consider the impacts on small retailers of the current point of obligation in EPA's response to the petitions to change the point of obligation.[100] EPA has done as the Coalition has suggested, and EPA's analysis is provided in this document.

While the EPA recognizes the very real economic challenges faced by single-store owners and medium sized gas stations and convenience stores, we do not believe these challenges are primarily, or even materially, the result of the current point of obligation in the RFS program or the RFS program more generally. As discussed in further detail in Section II.C above, EPA does not believe that the comments submitted on our proposed denial adequately support the claims that large retailers and unobligated blenders are able to realize windfall profits from RIN sales. After carefully reviewing the comments and the available market data the EPA reaffirms that while unobligated parties that acquire RINs by blending renewable fuels (such as large retailers) can and generally do receive significant revenue through the sale or RINs, there is a cost to acquiring these RINs that is approximately equal to the revenue received through their sale. We also note that it is implausible that such a significant price advantage ($0.10 to $0.15 cents per gallon according to the Small Retailers Coalition, which is approximately 3 times higher than the average profit per gallon)[101] could be sustained in the highly competitive retail fuel market. To the degree that larger competitors are able to access lower cost fuels, there is no basis for concluding that these advantages are attributable to the RFS program. Rather, we believe that the significant challenges faced by many small retailers are rather the result of challenges in the retail fuels market such as a declining demand for refined transportation fuels (particularly gasoline), increased competition from large retailers and high-volume retail outlets, a lack of flexibility in fuel purchasing options relative to larger (often unbranded) retailers, and many others, many of which were mentioned by the small retailers in their own comments. After reviewing the information submitted by the petitioners and commenters, along with other market data, EPA has concluded that large retailers do not have the incentive or ability to effectively inhibit the greater use of renewable fuels in the United States (See Sections III.B – III.E below for a further discussion of these issues. While we understand that small retailers face significant economic challenges, these challenges are unrelated to the RFS program, and would not be fundamentally altered by changing the point of obligation in the RFS program.[102]

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[100] Comments from Small Retailers Coalition, EPA-HQ-OAR-0544-0185. The Small Retailers Coalition has also recently filed a complaint alleging that EPA has failed to do this analysis. See Small Retailers Coalition v. US EPA and Scott Pruitt, W.D. Tex., Case 7:17-cv-00121, Complaint filed 8/28/17.

[101] According to NACS, the average retail fuel margin is about 3 to 5 cents per gallon (NACS. *2015 Retail Fuels Report).*

[102] In addition to believing that the RFS program is not harming small retailers generally, the EPA has also been presented with claims that the RFS program can benefit small retailers. The EPA received comments from the Petroleum Marketers and Convenience Stores of Iowa indicating that small retailers are benefiting from the RIN value through RIN trading via third party aggregators. Comments from Petroleum Marketers and Convenience Stores of Iowa, EPA-HQ-OAR-2016-0544-0199.

E. The EPA Has Not Seen Evidence That High RIN Prices Have or Will Force Refiners to Decrease Production or Increase Exports

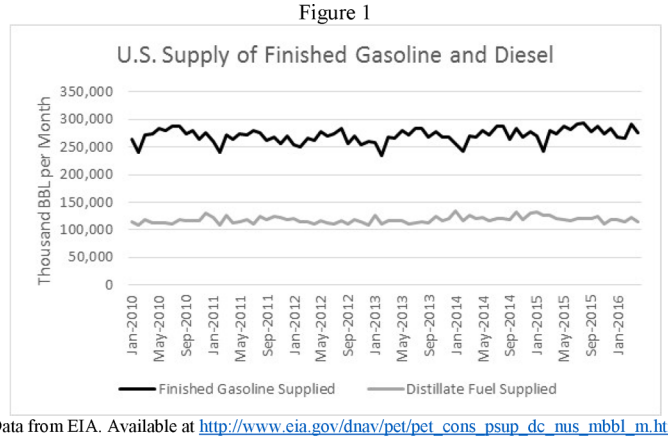
In their petition, Valero suggested that if the EPA does not change the point of obligation of the RFS program it could lead to obligated parties, particularly merchant refiners, decreasing their production of obligated fuels or increasing their exports of refined products in an effort to minimize the RFS obligations.[103] As discussed above, both merchant refiners and integrated refiners experience RIN acquisition costs, and both recover these costs through the price of the petroleum products they sell. The RFS program therefore does not impact merchant refiners in a way that would make them more or less likely than integrated refiners to decrease production of gasoline and diesel or increase exports of these fuels. Rather, decisions to decrease production or increase exports are driven by broader market factors, which effect both merchant and integrated refiners.

We also note that the idea that the RFS program could result in a reduced supply of gasoline and diesel to the United States through lower production volumes or increased exports is not new, as obligated parties have been suggesting that this could be a potential outcome of increasing RFS standards since the beginning of the program. Despite these warnings, and even with increasing vehicle fuel efficiency in the United States in previous years, the significant increase in both the RFS standards and RIN prices have not resulted in obligated parties taking these actions, as seen in the following graph.[104] Were high RIN prices to have this effect, one would expect to have seen a drop in fuel supply beginning in 2013, when RIN prices spiked.

[103] One commenter (NERA) claimed that since RIN costs are reflected in the wholesale price of gasoline blendstocks high RIN prices would encourage gasoline exports, as exported gasoline could receive the value of the RIN without incurring the RIN obligation. This commenter ignored the fact that the market price for exported gasoline is discounted relative to gasoline sold for the domestic market, and that this discount reflects the cost of the RIN obligation (for further discussion of this issue, see Section II.C above).

[104] The EPA also performed a separate analysis of refinery closures, derating, and expansions from 2013-2017. See Section III.G for a further discussion of the impact of the RFS program on refining capacity.

Figure 1



Data from EIA. Available at http://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_m.htm

The lack of any impact on finished gasoline and diesel supply to the United States is not surprising, since as was discussed in Section III.B.2 above, data reviewed by the EPA show that obligated parties are generally receiving higher prices for fuels they produce that are subject to an RFS obligation (gasoline and diesel fuel sold for use in the United States), which offsets the cost of compliance with the RFS program. By contrast, if they export the gasoline and diesel fuel, they would not have costs associated with acquiring RINs but would also not receive the higher value for their petroleum products associated with RFS compliance costs. An obligated party's ability to recover RIN costs through the price of obligated blendstocks in some ways is similar to their ability to recover fuel taxes. Though state fuel tax rates vary from state to state these differences in fuel tax rates do not cause fuel shortages in states with higher tax rates, as parties that sell fuel are able to recover the cost of the taxes in the prices of the products they sell. Companies make decisions about which market segments to participate in for a variety of reasons, but we believe the demand for transportation fuel in the United States is strong enough that refineries and importers will continue to meet demand on a competitive basis, even if participating in the market incurs RFS obligations.

Several commenters pointed to increased exports of refined products (gasoline and diesel fuel) in recent years as evidence that the RFS program, and high RIN prices in particular, were incentivizing increasing exports. We acknowledge that exports of gasoline and diesel have been higher in recent years relative to 2010.[105] We do not, however, believe that these increasing exports are driven by the RFS program. Notably, total production of finished gasoline and

[105] See EIA data on Weekly U.S. Exports of Total Distillate (https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WDIEXUS2&f=W) and Weekly U.S. Exports of Finished Motor Gasoline (https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=W_EPM0F_EEX_NUS-Z00_MBBLD&f=W).

distillate in the United States has increased significantly since 2010[106] due to a number of factors including access to low cost crude oil and natural gas and high refinery utilization rates. During this same time period, demand for refined products in the United States has been fairly constant.[107] Refiners seeking export markets for their products at a time when supply increases have outpaced domestic demand for their products is a natural response, and is unrelated to the RFS program.

F. A Relatively Small Number of Obligated Parties is Generally Advantageous

In the 2007 RFS1 rule, the EPA indicated that it considered it preferable to place the point of obligation on a smaller number of refiners and importers rather than on a larger number of downstream blenders. This is primarily because placing the obligation on a smaller number of parties with significant assets generally results in a more efficient, and therefore more effective program. In the proposed RFS2 rule, we noted that blenders would likely be regulated as RIN holders under the expanded program, and questioned whether also making them obligated parties would significantly increase their regulatory burden. After considering comments, we chose in the final RFS2 rule to maintain the RFS1 approach, noting, among other reasons, that changing the point of obligation to include blenders could lead to disruption of the program in the transition of RFS1 to RFS2. After promulgating the final RFS2 rule we gained additional experience implementing the program that further supports our decision to maintain the current approach. Under the current system, it is renewable fuel producers who generate RINs, for gallons of biofuel produced, and it is the refiners and importers of gasoline and diesel fuel who must retire the RINs to demonstrate compliance. While the EPA is engaged in compliance and enforcement activities to address instances of invalid RINs in the marketplace, the sheer volume of RINs and RIN transactions makes it critical to also leverage the participation of obligated parties in policing the RIN market. In addition, refiners and importers are subject to significant requirements related to environmental, safety, and health concerns, and the expertise they have developed in maintaining compliance contributes to the success of the RFS program.

Refiners and importers generally have greater resources that enable them to provide oversight of the RIN generators to help ensure that the RINs being traded in the marketplace are valid. They have invested significantly since the finalization of the RFS regulations to develop compliance processes and expertise in these markets. Changing the point of obligation would potentially disrupt the systems developed by these parties, strand their investments, and would require that newly obligated parties make the necessary investments to enable compliance with their new RFS obligations. This could take a significant amount of time and represent a significant

[106] See EIA data on U.S. Refinery and Blender Net Production of Distillate Fuel Oil (https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MDIRPUS1&f=M) and U.S. Refinery and Blender Net Production of Finished Motor Gasoline (https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MGFRPUS1&f=M).

[107] See EIA data on Weekly U.S. Product Supplied of Distillate Fuel Oil (https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WDIUPUS2&f=W) and Weekly U.S. Product Supplied of Finished Motor Gasoline (https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=WGFUPUS2&f=W).

financial burden to the new obligated parties, especially as we expect that many would be smaller companies with fewer resources than the existing obligated parties.

In contrast to the currently regulated refiners and importers, many "position holders" and blenders sell relatively small volumes of gasoline and diesel, and are likely relatively small entities without the personnel or expertise available to fill the role currently played by obligated parties in policing the validity of the RINs in the market. This concern was affirmed by our analysis of a data set recently provided to us by the Internal Revenue Service (IRS) (for a fuller discussion of the data the EPA received from IRS, and the EPA's assessment of this data, see Sections IV.A and IV.B). The IRS data set included the volume of gasoline and diesel sold by all "positions holders" aggregated into groups of five and arranged from highest to lowest volume.[108] When the EPA overlaid this data set with our volume data for obligated parties (grouped in the same manner as the IRS), we found there were about 300 more parties in the IRS data set. Moreover, as discussed below, when we compared the total volume associated with "position holders" we found that more than half of the "position holders" (those with the smallest volumes) were responsible for less than 1% of the aggregate volume. Our conclusion from this comparison is that there is a significant number of small volume parties that are current "position holders" (subject to the IRS fuel tax laws) that would become new obligated parties, would likely not be familiar with how to comply with the RFS requirements and may not have the resources to do so. While it is possible that they would develop this expertise over time, the relatively small size of many of these entities may mean that the important market-policing function currently performed by obligated parties could be largely compromised by changing the point of obligation. This result is more likely considering that the current obligated parties tend to have larger assets that could be put at risk from non-compliance, and therefore take compliance with the RFS very seriously. Placing the RFS compliance obligations on refiners and importers also reduces the overall cost associated with the RFS program, as these parties benefit from economies of scale and can better spread the costs associated with RIN acquisition and oversight over greater quantities of RINs.

In addition to these benefits to the program, a smaller number of obligated parties significantly decreases EPA's resource requirements associated with the administration of the RFS program. It reduces the number of annual compliance reports that must be reviewed by the EPA each year, and reduces the complexity associated with determining the volumes of gasoline and diesel for which each obligated party has a compliance obligation. This allows for more effective implementation and enforcement of the RFS program. In addition, we believe it is preferable to

[108] For example, IRS provided EPA with the total volume of gasoline and diesel sold by the 5 parties that sold the most gasoline and diesel, the total volume sold by parties that sold the 6^{th} – 10^{th} highest volumes of gasoline and diesel, etc. This IRS data was provided to the EPA on May 22, 2017. See *IRS Aggregated Volume Data*. This data is treated as CBI.

place the RFS obligation on larger companies with greater resources who are better positioned to comply with the RFS standards.[109]

Several commenters contested the EPA's statements that changing the point of obligation to the "position holders" would increase the number of obligated parties.[110] These commenters further argued that parties with enough capital and expertise to purchase fuel in bulk above the rack would be able to comply with RFS obligations. However, based on information from the IRS (discussed briefly above and further in Section IV.A and IV.B), we determined that if the point of obligation in the RFS program were placed on the "position holders," the number of obligated parties would increase significantly, and that many of these parties sell relatively small volumes of gasoline and diesel.

We note that if we had compelling evidence in front of us that placing the RFS obligation on a larger number of renewable fuel blenders or "position holders" would significantly increase the production, distribution, and use of renewable fuels, then a potentially higher number of obligated parties on its own would not likely be a reason to retain the current point of obligation. In light of the reasons discussed above, however, and because we do not think shifting the point of obligation would lead to higher renewable fuel production and use, and for other reasons discussed in this document, we believe that placing the obligation on the smaller number of refiners and importers is preferable.

G. The Current Program Structure Does Not Require Market Repositioning to Achieve Compliance

One of the petitions the EPA received requesting a change in the point of obligation in the RFS program took issue with language in previously published EPA documents suggesting that one potential avenue for obligated parties to acquire RINs is the purchase or construction of downstream blending assets.[111] The petitioner emphasized the challenges associated with the acquisition of such assets. They further claimed that this suggestion reflects a lack of understanding of the complexities of the fuel market, and implicitly suggests that investment in blending infrastructure is the only solution for merchant refiners to comply with the RFS.

The EPA strongly disagrees with the petitioner's assessments of the EPA's previous statements. In the document referenced by the petitioner, the EPA notes that the acquisition of downstream assets is merely one option open to obligated parties who seek an alternative to purchasing separated RINs necessary for compliance. The fact that ownership of positions at terminals and

[109] While the evidence before EPA demonstrates that the cost of RINs are generally recovered by the obligated parties, larger companies with greater resources are significantly more likely to have expertise related to complying with EPA regulations (including, but not limited to their RFS obligations), ensuring the validity of RINs, etc.
[110] For example, see comments submitted by Valero, EPA-HQ-OAR-2016-0544-0274; AFPM, EPA-HQ-OAR-2016-0544-0360; Monroe Energy, EPA-HQ-OAR-2016-0544-0368
[111] See Valero Energy Corp. Petition for Rulemaking, June 13, 2016, 16-17. Valero referred to statements made by EPA in *A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects* (May 14, 2015), written by Dallas Burkholder.

access to pipeline capacity[112] has continually changed over time suggests that similar changes are possible in the future, if parties were motivated to pursue these options. Most importantly, however, the EPA disagrees with the statement that our suggestion that acquiring downstream assets as one possible option open to obligated parties implies that ownership of these assets, as well as ownership of hydrocarbon at the time when renewable fuel is blended (generally at the rack), is the only option for acquiring the RINs needed for compliance with the RFS obligations. The EPA created the RIN system in accordance with Congressional direction, both as a general compliance mechanism for the RFS program and to allow for the generation and use of credits.[113] Purchasing separated RINs remains an option available for all parties to acquire the RINs that are needed by obligated parties. The active market for RINs, which includes a significant stock of carryover RINs, demonstrates that RINs are available to parties who wish to purchase them. For example, according to EPA data there were over 50 billion RIN trades for the 2014 compliance year (the most recent year for which data are available).[114] We firmly believe that the RIN market is capably fulfilling this intended purpose of creating an avenue for obligated parties to comply with their RFS obligations by purchasing RINs, rather than requiring the acquisition of distribution and blending infrastructure and/or ownership of petroleum fuels at the rack. In this way, the RIN market enables compliance with RFS obligation without disrupting the fuels marketplace. Rather than a necessity, the acquisition of downstream infrastructure to enable direct access to RINs through the blending of renewable fuels at the rack remains one of several options. Parties may also purchase separated RINs in the RIN market, enter into contracts with other parties that blend renewable fuels to obtain RINs, and purchase renewable fuel with attached RINs, separate the RINs, and resell the renewable fuel without RINs in order to acquire the RINs needed to comply with the RFS standards.

H. The Current RIN Market Does Not Appear to be Subject to Significant Manipulation, and a Change in the Point of Obligation will not Reduce Fraud

Some commenters suggested the RIN market is not functioning due to manipulation and speculation within the market. Others noted that a lack of transparency in the RIN market allows for speculation, and that a revision of the definition of obligated party would increase transparency and reduce market abuse. It is not clear from comments how changing the definition of obligated party would increase transparency. Although the EPA has not seen evidence of manipulation in the RIN market, claims of market manipulation prompted the EPA to execute a memorandum of understanding (MOU) with the U.S. Commodity Futures Trading Commission (CFTC), which has the authority and expertise to investigate such claims. The EPA will continue to apprise the CFTC of allegations regarding potential market manipulation.[115]

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[112] While the ownership of positions at terminals and pipeline capacity are not necessary to enable ownership of gasoline or diesel blendstocks at the rack, owning positions at terminals and pipeline capacity are ways for obligated parties to retain ownership of petroleum blendstock at the rack, where it can be blended with renewable fuels.

[113] See CAA 211(o)(5).

[114] See Annual RIN Sales/Holdings Summary on EPA public website: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-rin-salesholdings-summary

[115] Some commenters alleged speculation was negatively impacting the functioning of the RIN market. Speculation is a normal part of the market. Market participants that *speculate* on future supply or demand, and therefore prices, aren't doing anything wrong. In fact, this helps the market ensure that the future demand is met at the lowest overall

Some commenters suggested that third party speculators (parties that are not involved in the production or blending of renewable fuels and are not obligated parties) and RIN-long parties are withholding RINs to drive up prices. They allege that third parties and RIN-long parties[116] are profiting from these actions at the expense of small and merchant refiners. These commenters have not provided sufficient evidence to support their claims that integrated refiners or unobligated blenders (who would likely be RIN long) are intentionally withholding RINs from the market in an effort to manipulate RIN prices. As discussed further in Section II.B above, we do not believe that current RIN prices reflect successful efforts by some parties to artificially inflate RIN prices, but rather that they are reflect the costs associated with producing additional volumes of renewable fuel (in the case of biodiesel) or the financial incentives needed to sell additional volumes of higher level blends of renewable fuel (in the case of ethanol).

The EPA received some other comments that changing the point of obligation to the "position holders" would reduce fraud in the RFS program. These parties generally claimed that "position holders" are better equipped to ensure the validity of RINs because they are closer to the actual point of blending. In response to these comments, EPA notes that the majority of the RIN fraud seen in the RFS program to date has been for RINs associated with biodiesel. The majority of biodiesel is blended with diesel downstream of the rack. Therefore, "position holders," who by definition transfer ownership of the fuel at the rack, may be in no better position to monitor biodiesel blending than a refiner. Under the current Part 80 regulations, each obligated party incurs an RVO for both diesel and gasoline, even if they are only producing one of the two types of fuel. Likewise, if the point of obligation moved to "position holders," even "position holders" that only blend ethanol into gasoline would still incur an RVO for diesel and would still be required to acquire RINs from biodiesel blending.

Several commenters pointed to comments from Doug Parker indicating that the chain of custody between producer, blender, and refiner has led to fraud within the RIN market. As an initial matter, historically, EPA has seen fraud within the RIN market at locations upstream of the point of compliance and the point of obligation. Generally, defendants in the majority of the RIN fraud cases brought to date generate RINs for fuel that is never produced, generate RINs for fuel that is not used for a qualifying purpose (transportation fuel, heating oil or jet fuel), or export renewable fuel without retiring the appropriate RINs. These cases have resulted in significant criminal convictions and a substantial number of associated civil enforcement cases. The EPA believes that our enforcement actions and increased due diligence by RIN purchasers have helped to deter these types of violations, and note that these fraud cases are unlikely to have been prevented by a different point of obligation due to the nature of the fraud.

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price possible. Unlike market speculation, market *manipulation* involves a deliberate (and illegal) attempt to interfere with the free and fair operation of the market and create artificial, false or misleading appearances with respect to the price of, or market for, RINs.

[116] RIN-long parties are those who obtain more RINs through blending than their obligation under the RFS program; i.e., they are "long" on RINs as compared to their obligation.

Some commenters, relying on Doug Parker's analysis suggested that "shortening the RIN chain of custody between the point of compliance[117] and the point of obligation" would inherently reduce the opportunity and incentive for fraud.[118] These comments suggest that the current "chain of custody" places refiners and importers "multiple steps removed from the decision point on where renewable fuel is purchased in order to blend it,"[119] and that blenders have direct engagement with renewable fuel producers and are better able to "assess the quality and integrity of their suppliers."

These commenters suggested that a change to the point of obligation would place compliance through blending closer to the renewable fuel source and would improve verification. Despite commenters suggestions to the contrary, the chain of custody between renewable fuel producers and obligated parties could be just as long as it is currently, and would likely be as long in the case of biodiesel, where renewable fuel is blended beyond "position holders," as discussed above. Because obligated "position holders" would still have four unique renewable fuel volume obligations, they would likely still have to sell and purchase RINs to meet their RVOs for types of renewable fuel which they are unable to blend. This is especially true for "position holders" that primarily sell a single fuel type, such as gasoline or diesel, and therefore have limited opportunities to blend ethanol or biodiesel respectively. Doug Parker's initial comments may have been based on a theory where the "blender" would be obligated, and would be the person with access to the renewable fuel that would be blended. For ethanol blending, the blender and the "position holder" are likely the same person, however, for biodiesel, it is much less likely that the blender and the "position holder" are the same person. In his comments, he states that "changing the point of obligation to the location where actual decisions are made on blending conventional and renewable fuel would . . . significantly enhance compliance and reduce opportunities for fraud."[120] However, changing the point of obligation to "position holders" would not always place the point of obligation where "actual decisions are made on blending;" for example, biodiesel blending decisions are often made below the rack. Thus, the disconnect between the point of obligation and the point of blending could still exist, and likely would for biodiesel. While changing the point of obligation to the position holder may shorten the chain of custody for RINs associated with ethanol, most of which is currently blended at the rack, we note that the vast majority of RIN fraud cases to date have been associated with biomass-based diesel (D4) RINs.

There continues to be a significant risk of invalid RINs in the market arising from the use of improper feedstocks, unapproved pathways or even improper attribution of pathways (e.g. overstating production of renewable fuel from cellulosic vs. non-cellulosic feedstocks). Smaller parties with less resources will have correspondingly less likelihood of detecting these problems. Doug Parker, in comments, also suggested that "soaring prices of RINs" act as an additional incentive for fraud. The EPA does not dispute that fraudulent activity often occurs for financial

[117] Although the "point of compliance" is not defined in Parker's comments, EPA believes that this would be the point where renewable fuel is blended with non-renewable fuel. As mentioned above, for ethanol blending, this often occurs at the rack, however blending of biodiesel occurs most often downstream from the rack.
[118] See, e.g., Comments from Small Refiners' Coalition, HQ-OAR-2015-0054-0406.
[119] Parker, Doug. Update to: September 4, 2016 White Paper Addressing Fraud in the Renewable Fuels Market and Regulatory Approaches to Reducing this Risk in the Future. February 3, 2017.
[120]

gain, but EPA disagrees that moving the point of obligation will reduce the price of RINs as discussed in this section and in Section III.

In arguing for a change in the point of obligation, Monroe Energy suggested that under the current definition of "obligated party," blenders and non-obligated parties who sell RINs have no incentive to ensure that their RINs are valid, and that refiners and importers are the only parties at risk when purchasing potentially fraudulent RINs. The EPA notes that Monroe's statement is inaccurate since parties who sell RINs must register under the RFS program, and can be held liable if the RINs they sell are deemed invalid or fraudulent. Therefore, they do indeed have an incentive to ensure that RINs they purchase and sell are valid. However, we also believe that larger entities, with more assets at risk and more resources to devote to compliance, are more likely to engage in in-depth due diligence investigations into RIN validity than smaller, less sophisticated parties. Therefore, a scheme that eliminated many larger refiners and importers from the obligation to acquire RINs, and shifted RIN responsibilities to smaller entities such as many "position holders" and blenders, would be more likely to result in an increase, rather than a decrease in instances of RIN fraud. BP and others who do not favor a change in the point of obligation suggested that smaller parties who could become obligated if the point of obligation were changed may not have the capability to conduct due diligence to ensure that the RINs they acquire are valid. Once the relaxation of RIN verification occasioned by such a change in the point of obligation were noticed, the change could encourage the generation of fraudulent RINs.

III. Changing the Point of Obligation in the RFS Program Is Not Expected to Result in the Increased Production, Distribution, and Use of Renewable Fuels

We have discussed in the previous section several significant concerns about the impact changing the point of obligation would have on the RFS program. Given these concerns, and our overall obligation to implement the RFS program in a way that most fully achieves Congress's goal of increasing renewable fuel use, the point of obligation should only be changed if it would be expected to lead to net benefits. As we discuss in this section, we do not believe that the record before us indicates that this is the case.

In their petitions submitted to the EPA requesting a change to the point of obligation in the RFS program the petitioners claim that changing the point of obligation could result in greater production, distribution, and use of renewable fuels in the United States. The petitioners suggest that changing the point of obligation could therefore reduce or even eliminate the need for the EPA to exercise our waiver authorities. The petitioners generally offer only theoretical arguments to support these claims. In this section we describe our evaluation of petitioners' claims that changing the point of obligation would increase the production, distribution, and use of renewable transportation fuels in the United States.

The use of the EPA's waiver authorities to reduce the required volume obligations from the statutory levels in recent years is primarily the result of the delay in the commercialization of cellulosic biofuels and resulting shortfall in cellulosic biofuel production volumes relative to the statutory targets. In addition to the shortfall in cellulosic biofuel production, the EPA also noted challenges associated with increasing the supply of renewable fuel to consumers associated with

distribution and use of renewable fuels, particularly ethanol and biodiesel in its rule establishing the RFS standards for 2014-2016.

In their petitions, the parties requesting that the EPA change the point of obligation did not address how changing the point of obligation might impact the shortfall in cellulosic biofuel production,[121] but instead narrowly focus on the impacts on the distribution and use of other renewable fuels, particularly ethanol and biodiesel that they believe would result from changing the point of obligation. The petitioners argue that changing the point of obligation could increase the supply of renewable fuel to consumers by increasing the blending infrastructure for renewable fuels, improving the retail pricing of fuel blends with higher renewable fuel content relative to those with lower renewable fuel content, and increasing the availability of transportation fuels with higher level blends of renewable fuels at the retail level.

After reviewing the petition submissions, other available data and letters opposing changing the point of obligation from companies and associations involved in the renewable fuel production, fuel distribution and renewable fuel blending industries,[122] and the many comments received on the proposed denial, we continue to believe that the benefits to renewable fuel blending claimed by the petitioners are highly unlikely to occur. As explained below, the data available to EPA does not indicate that changing the point of obligation would result in an increase in the infrastructure needed to blend renewable fuels at terminals or offer these fuels at retail stations, nor would it be expected to appreciably impact the price of renewable fuel blends at the retail level. While we have received comments from large renewable fuel producers[123] and associations representing renewable fuel producers[124] opposing changing the point of obligation, only a few renewable fuel producers or associations have expressed support for changing the point of obligation.[125] Some of the renewable fuel producers that supported changing the point of obligation appeared to do so conditionally, requesting that EPA consider factors such as increasing requirements for renewable fuel use and promoting predictability and stability for all sectors in our decision on the point of obligation.[126] Other renewable fuel producers acknowledged the potential concerns with changing the point of obligation while expressing the belief that changing the point of obligation could lead to positive outcomes, and concluded by simply requesting that the EPA consider a rulemaking process to receive stakeholder input on this issue.[127] Since renewable fuel producers would stand to gain from any RFS structural changes that would increase the distribution and use of renewable fuels, their general opposition to a change in the point of obligation is significant.

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[121] Several petitioners and commenters did address this issue in their comments on the proposed denial of the petitions to change the Point of Obligation in the RFS program. These comments are addressed in Section III.F below.

[122] See Presentation from Murphy USA to EPA, August 16, 2016; Letter from RaceTrac to Administrator McCarthy, August 17, 2016; Letter from QuikTrip to Administrator McCarthy, August 17, 2016; Letter from Tim Columbus to Administrator McCarthy, August 15, 2016; Letter from Pilot Flying J to Administrator McCarthy, August 16, 2016; Letter from SIGMA and RFA to Congressmen Whitfield and Rush, June 30, 2016.

[123] Comments from REG on the proposed RFS standards for 2017 and the biomass based diesel standard for 2018 (EPA-HQ-OAR-2016-0004-3477).

[124] Letter from SIGMA and RFA to Congressmen Whitfield and Rush, June 30, 2016.

[125] For example, see comments submitted by Valero Renewable Fuels Company, EPA-HQ-OAR-2016-0544-0413.

[126] For example, see comments from Crimson Renewable Energy, EPA-HQ-OAR-2016-0544-0376.

[127] For example, see comments from AgriFuels, EPA-HQ-OAR-2016-0544-0210.

Additionally, the EPA notes that the agency did not exercise the general waiver authority on the basis of inadequate domestic supply in establishing the 2017 RFS standards, and did not propose to do so for the 2018 standards. Thus, EPA established for 2017, and proposed for 2018 EPA, volume reductions that are attributable to insufficient production of cellulosic biofuel. We do not believe that this type of shortfall would be reduced or alleviated by a change in the point of obligation. Thus, the focus of the petitioners on potential impacts of a change to the point of obligation on distribution and use of renewable fuels such as ethanol and biodiesel is not even directed at the primary hurdles facing renewable fuel growth under the RFS program going forward. Finally, the United States Court of Appeals for the District of Columbia Circuit recently ruled that EPA's interpretation of the "inadequate domestic supply" portion of its waiver authority in developing the 2016 total renewable fuel standard was inappropriate, and that in the future EPA may only consider "supply-side factors: in assessing if an "inadequate domestic supply" of renewable fuel exists.[128] Therefore, to the extent that petitioners claim that a change in the point of obligation would overcome constraints in the distribution of renewable fuel from refiners, importers or blenders to consumers, or in the use of renewable fuel by consumers, it does not appear that this would lead to a difference in EPA's use of the inadequate domestic supply waiver authority under the direction EPA recently received from the DC Circuit. For these and other reasons, as discussed below, contrary to the petitioners' claims, the EPA believes that the production, distribution, and use of renewable transportation fuels is unlikely to be positively impacted by changing the point of obligation in the RFS program.

Before assessing the potential impacts on renewable fuel production, distribution, and use in the subsections that follow we first address the EPA's statutory authority to place the point of obligation on various suggested parties.

A. Some of the Proposed Changes to the Point of Obligation Are Inconsistent with the CAA

EPA believes that certain of the proposed changes to RFS point of obligation are inconsistent with the Clean Air Act. Although we note these inconsistences here, we emphasize that our denial of the petitions is not dependent on this legal analysis. For the reasons described elsewhere in this document, the EPA would deny the petitions seeking a change in the point of obligation even if it concluded that it had legal authority to enact the suggested changes.

In its petition for reconsideration, the Coalition recommends that the EPA move the point of obligation to "blenders and distributors" without addressing EPA's authority to do so consistent with CAA 211(o)(3). See Coalition Petition, p. 14. In its petition, the Coalition cites text from CAA 211(o)(2)(A)(iii) indicating that the regulations EPA establishes to implement the RFS program "shall contain compliance provisions applicable to refineries, blenders, distributors, and importers, as appropriate." The Coalition suggests that including "distributors" in this list of entities regarding which compliance provisions may be established would authorize the EPA to establish the point of obligation for compliance with the RFS annual standards on distributors. However, the Act includes a different provision specifically identifying the parties that may be

[128] See *Americans for Clean Energy v. Environmental Protection Agency*, No. 16-1005, Slip Op. 31-32 (D.C. Cir. July 28, 2017) ("*ACE*").

required to comply with the annual percentage standards. CAA 211(o)(3) describes the requirement for the EPA to establish annual standards under the Act, and provides that "[t]he renewable fuel obligation . . . shall . . . be applicable to refineries, blenders, and importers, as appropriate."[129] Distributors are excluded from this list. Reading these two provisions together, EPA's interpretation is that it has authority to establish ancillary compliance provisions which apply to distributors, but it does not have authority to make distributors directly subject to the annual percentage standards.[130, 131]

A number of Petitioners and other commenters suggest that the point of obligation be placed on "position holders."[132] They explain that "position holders" may or may not be blenders, but they argue that because all "position holders" could be blenders, the EPA has the authority to impose the point of obligation on them. They propose that the "obligation [would attach] whether a party actually blends or not," and explains that their proposed definition of obligated party "does not even make actual blending critical."[133] In comments, Petitioners suggested that the EPA has broad authority to obligate "position holders" as a subset of blenders because they "control the point of blending." Commenters also suggested that the EPA could redefine "refiner" and "refinery" to include "position holders." Some commenters suggested that the EPA's past consideration of its authority to impose the point of obligation on downstream parties means the EPA must have the authority to regulate "position holders."

The EPA does not interpret CAA 211(o) as authorizing it to make "position holders" subject to the renewable volume obligation if they are not blenders, importers or refiners. EPA received comments from the Association of American Railroads, the American Trucking Association and UPS indicating that they or their members are not refiners, importers, or blenders, and yet would be obligated under the proposed definition of obligated party because they are "position holders."[134] A "position holder" may have authority to decide whether or not to blend renewable fuel into non-renewable fuel at a particular terminal, but EPA does not interpret the term

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[129] CAA 211(o)(3)(B)(ii)(I).

[130] We believe that moving the point of obligation to distributors in addition to, or in the alternative to, blenders and "position holders," would result in imposition of the obligation on a large number of new parties, including small businesses. As discussed in Sections II.E. and IV, we believe that this would be a generally undesirable result, unless it could clearly be demonstrated that such a change would result in net benefits, potentially including the increased production, distribution and use of renewable fuels. However, for the reasons discussed elsewhere, including in Sections III.B.-E., we do not believe that this would be the case.

[131] EPA notes that the Coalition has moved away from this interpretation in its comments, and instead advocates that the definition of "obligated party" should be changed to obligate "position holders." In their comments on the RFS 2014-2016 final rule, they urged EPA to place the obligation on "position holders," Comments from Small Refiners Coalition Comments on Renewable Fuel Standard Program: Standards for 2014, 2015, and 2016 and Biomass-Based Diesel Volume for 2017, HQ-OAR-2015-0111-2339, and in the comments on the proposed denial, the Coalition also suggested that EPA define "obligated party" to include "position holders." Comments from Small Refiners Coalition, HQ-OAR-2016-0544-0406, 5. In the alternative, the Coalition argues that EPA clearly has the authority to obligate all blenders. Ibid.

[132] In its petition, Valero uses the term "rack sellers" to represent those parties who own fuel above the rack. As mentioned above, we have chosen instead to use the term "position holders" to describe these parties.

[133] Valero Petition for Rulemaking, June 13, 2016.

[134] Comments from Association of American Railroads, EPA-HQ-OAR-2016-0544-0359; Comments from American Trucking Association, EPA-HQ-OAR-2016-0544-0355; Comments from UPS, EPA-HQ-OAR-2016-0544-0076.

"blender" in CAA 211(o) as describing anyone who is in a position to choose whether or not to engage in blending, but rather as describing those parties who actually engage in blending.[135] EPA also does not believe it would be appropriate to redefine the terms "refiners" and "importers" to include "position holders" who do not engage in any refining or importing. Such an approach would not be consistent with EPA's existing regulatory definitions or common industry usage. In sum, EPA does not interpret the CAA as authorizing it to place the point of obligation on all "position holders" or distributors, since they are not all refiners, importers or blenders. Of course, EPA does have authority to place the point of obligation on blenders (which would include the majority of the "position holders"), but for reasons discussed further below we continue to find it appropriate not to do so.

B. Renewable Fuel Production, Distribution, and Use Does Not Appear to Be Significantly Limited by Blending Infrastructure

One of the ways that the petitioners claim renewable fuel production, distribution, and use could be positively impacted by changing the point of obligation in the RFS program is by increasing the incentive for the installation and expansion of renewable fuel blending infrastructure, especially at terminals. The petitioners claim that the current point of obligation results in a number of parties that are either "naturally long on RINs," because they are obligated parties that blend renewable fuels at volumes above their RFS obligations (generally because they blend renewable fuel into more petroleum products than they refine or import), or because they blend renewable fuels but are not obligated parties under the RFS program. According to the petitioners and some commenters, these parties have an incentive to oppose the installation and expansion of infrastructure needed to increase the blending of renewable fuels into transportation fuel in an effort to restrict RIN availability and drive up RIN prices.[136] The EPA has investigated these claims and does not find them to be supported. We acknowledge that some parties may be hesitant to contribute financially towards the addition of new infrastructure at terminals to increase the availability of higher level blends of renewable fuels due to insufficient local demand for these fuels (in the case of E85) or previous investment in infrastructure to offer these blends outside of the terminal (in the case of biodiesel). As discussed further in Section III.C below, we do not believe the addition of such infrastructure would be likely to increase the availability of RINs to such a degree that it would appreciably impact the price of RINs. It is therefore highly unlikely that any opposition to additional blending infrastructure at terminals is driven by a desire to restrict RIN availability which could theoretically result in higher RIN prices.

The EPA spoke with several terminal owners/operators to assess the current status of renewable fuel blending infrastructure at terminals.[137] Currently all, or nearly all, terminals contain the necessary infrastructure for the onsite storage of ethanol and the blending of ethanol with

[135] A decision to treat people as having engaged in an activity simply because they have the opportunity to engage in it would be quite unusual. For example, a landowner not making active use of their land would not normally be considered a "farmer" simply because they could decide in the future to engage in farming.
[136] For example, see *Effects of Moving the Compliance Obligation under RFS2 to Suppliers of Finished Products*, NERA Economic Consulting, July 27, 2015.
[137] See Magellan Meeting Notes, December 16, 2015; Independent Fuel Terminal Owners Association meeting notes, January 8, 2016; Kinder Morgan meeting notes, January 22, 2016.

gasoline. This infrastructure is generally used to blend petroleum blendstocks with 10% ethanol by volume to produce a finished E10 blend. Some terminals have invested in additional infrastructure, such as additional ethanol storage capacity and/or larger capacity lines and nozzles, to more readily accommodate the production of fuel blends that contain a higher proportion of ethanol, such as E85. Even without this additional infrastructure, however, all of the terminal owners/operators communicated to the EPA that they were capable of producing fuel blends that contain a higher proportion of ethanol with their existing equipment. They also expressed a willingness to make the relatively modest changes necessary to accommodate faster loading times[138] if the existing infrastructure resulted in loading delays for trucks at the rack. Based on these conversations, as well as the comments received, EPA does not believe that blending infrastructure at terminals is a significant factor limiting the sale of higher level ethanol blends. EPA further notes that the preponderance of ethanol produced and used in the United States is conventional (non-advanced) ethanol, and since EPA determined that the implied statutory volume of 15 billion gallons of conventional fuel would be supplied in 2017 and has proposed a similar finding for 2018, that increases in ethanol distribution infrastructure does not appear necessary to attain the statutory volume targets for conventional and non-cellulosic advanced biofuels.

Biodiesel blending infrastructure at terminals is less universal than ethanol blending infrastructure, but substantially more blending occurs downstream of terminals for biodiesel as compared to ethanol. Production and use of biodiesel has been steadily increasing in recent years, and there is a paucity of evidence suggesting the lack of blending infrastructure poses an obstacle or constraint on further biodiesel use. In fact, biodiesel blending is well above the required volume. While we were unable to determine precisely what percentage of terminals have biodiesel blending infrastructure, the terminal owners/operators generally communicated that they were willing to install biodiesel blending infrastructure at terminals in situations where biodiesel is available and they could reasonably expect a return on these investments.[139] A review of publicly available information from OPIS suggests that approximately half of all terminals list prices for biodiesel and/or biodiesel blends.[140] This may in fact under-estimate the actual availability of biodiesel blends at terminals as diesel fuel containing up to 5% biodiesel is not required to be labeled as a biodiesel blend.[141] In situations where biodiesel blending infrastructure is not present at terminals, other parties have invested in alternative blending infrastructure to produce biodiesel blends downstream of terminals, further increasing the availability of biodiesel blends. Several large truck stop chains, driven by a desire to offer their customers lower priced fuel, have invested in infrastructure at retail locations to provide biodiesel blends for that location, and in some cases at other nearby retail stations.[142] Similarly, "jobbers" may take diesel fuel from bulk terminals and blend it with biodiesel before subsequent

[138] Because most ethanol blending infrastructure is currently designed to produce E10 blends, producing higher level blends using the existing infrastructure can require longer loading times.
[139] Magellan Meeting Notes, December 16, 2015.
[140] See OPIS Rack City List (http://www.opisnet.com/resources/rackcode.aspx#biodiesel). Approximation made by comparing the number of cities for which OPIS lists gasoline and diesel prices to the number of cities for which OPIS lists biodiesel prices.
[141] See ASTM D 975.
[142] See National Biodiesel Board comments on 2017 Annual Standards Rule; Attachment 6 (EPA-HQ-OAR-2016-0004-2904).

distribution, providing another opportunity for biodiesel blending.[143] In these cases it is unclear what impact, if any, changing the point of obligation to "position holders" would have on the availability of biodiesel blends as the current regulations appear to be providing a substantial incentive for parties to invest in biodiesel infrastructure, both at terminals and at other downstream locations.[144] As noted earlier, the required volume of biomass based diesel for 2017 is twice the statutory minimum volume. To the extent that renewable fuel use may be currently constrained by insufficient blending infrastructure we do not believe that changing the point of obligation would result in the additional investments claimed by the petitioners, as many of the parties that would become obligated if the petitioners' requests were granted are already investing in blending infrastructure. While the EPA continues to believe that there may be parts of the country that have limited or no access to biodiesel or biodiesel blends, this is generally the result of the higher expense and logistical complications associated with transporting biodiesel or biodiesel blends long distances to areas with little or no local biodiesel production, rather than an inability or unwillingness to invest in the necessary blending infrastructure, either at or downstream of the terminals. Furthermore, such cases continue to decline as a result of the continuing investment in biodiesel distribution infrastructure.

The EPA received comments claiming that changing the point of obligation would likely increase investment in biodiesel blending infrastructure at terminals, and that this would lead to higher biodiesel use in the United States.[145] Commenters claim that the most cost effective point to blend biodiesel is at the terminal, but that currently obligated parties with sufficient RINs and/or unobligated blenders are blocking the installation of additional biodiesel blending infrastructure at terminals. If the point of obligation were changed, they argue that the equal obligations at the rack would result in greater investment in biodiesel blending infrastructure at the rack. In his comments Mr. Jobe, president of Rockhouse Advisors, argues that because most biodiesel blending currently takes place downstream by a relatively small number of large companies this allows these companies to realize significant profits by keeping biodiesel prices low and/or keeping D4 RIN prices high.[146] He further argues that the current point of obligation discourages domestic biodiesel by encouraging the import of biodiesel at a lower cost, and that moving the point of obligation could benefit domestic producers by moving the demand for biodiesel away from the coasts to the approximately 1,000 terminals around the country.

The EPA believes it is highly unlikely that the many claimed benefits to the biodiesel industry associated with changing the point of obligation would occur. All or nearly all of these claimed benefits are dependent on additional investment in biodiesel blending at terminals. However, as Mr. Jobe notes in his comments, the response to increasing RFS requirements for biomass-based diesel and advanced biofuel has primarily been to increase biodiesel blending capacity downstream of the terminals. This is likely occurring because the parties that are currently blending the majority of the biodiesel have determined that it is more cost effective to blend

[143] Ibid.
[144] However, changing the point of obligation to "blenders" would make every truck stop or fuel retailer that blends biodiesel subject to the RFS. This could result in a reduction in downstream blending of biodiesel (as these parties concluded it was no longer worthwhile to engage in blending), or else could bring a large number of small entities, with little relevant compliance experience, into the RFS program.
[145] See, e.g., comments submitted by Joe Jobe, President of Rockhouse Advisors, LLC, EPA-HQ-OAR-2016-0544-0271.
[146] Ibid.

biodiesel downstream of the terminal, rather than at the terminal itself, and not because a small number of companies are exercising market power to reap excess profits. This is the case even though the majority of obligated parties (refiners and importers) are "position holders," and would stand to benefit by adding biodiesel blending infrastructure at terminals if this were likely to result in lower cost compliance options. Further, Mr. Jobe does not present compelling evidence that the current price of biomass-based diesel RINs is the result of a relatively few large biodiesel blenders ability to artificially inflate RIN prices. Rather, the high price of biomass-based diesel RINs is generally the result of the relatively high cost of biodiesel production due to the high cost of the marginal feedstock (generally virgin soy oil) relative to petroleum diesel.[147]

If the EPA were to change the point of obligation to "position holders" it would result in increased obligations for many of the parties that currently sell gasoline and diesel at the rack, including both those that are currently obligated parties and those that are not.[148] Mr. Jobe claims this would increase the incentives for parties who sell gasoline and diesel at the rack to invest in biodiesel blending infrastructure at the rack, as they would now all be "RIN-short" and would need additional RINs to meet their RFS obligations.[149] However, if the majority of the biodiesel blending (and thus BBD RIN separation) is currently occurring downstream of the rack by parties such as truck stop owners with little to no RFS obligations, as claimed by the commenters and supported by the data they present, this strongly implies that most obligated parties currently selling gasoline and diesel at the rack are already "RIN-short" with respect to biomass-based diesel RINs and must obtain at least some portion of their required BBD RINs through purchasing separated RINs.[150] It follows that because most parties that sell gasoline and diesel at the rack are likely RIN-short with respect to their biomass-based diesel obligations, that terminals should already have a significant incentive to add biodiesel blending infrastructure. There are two cases in which this would not be true; if purchasing separated RINs from the large unobligated blenders is a more cost effective way of acquiring D4 RINs than adding biodiesel blending infrastructure at the terminal, or if the unobligated blenders are sufficiently able to block the installation of the necessary infrastructure. If the former is the case, it appears unlikely that changing the point of obligation will cause parties to choose a more

[147] According to USDA's August 25, 2017 National Weekly Ag Energy Round-up the price for crude soybean oil was approximately $0.34 per pound. Each gallon of biodiesel requires approximately 7.5 pounds of feedstock, which would result in a feedstock cost of approximately $2.55 per gallon of biodiesel produced from soy oil. According to the Energy Information Administration, the spot price for No. 2 ULSD on August 25 ranged from $1.59 - $1.73, depending on location. For biodiesel produced from soy oil (likely the marginal gallon of biodiesel) the feedstock cost alone is significantly greater than the wholesale cost of petroleum diesel, before considering other costs of production such as labor, energy, capital recovery, etc.

[148] Currently obligated parties could see their obligations increase if they may sell more fuel across the rack than they currently refine. Because the proposed change to the point of obligation would make the obligation proportional to the amount of fuel sold over the rack, this could result in an increase for rack sellers in this position.

[149] Mr. Jobe's comment also appears to assume increasing RFS standards that would require obligated parties to continue to increase renewable fuel blending in subsequent years. If the standards do not increase substantially there would be no incentive to expand renewable fuel distribution infrastructure beyond what already exists, as using existing infrastructure is more cost effective than installing new infrastructure.

[150] While the IRS data assessed by EPA indicates there are a large number of "position holders" that are currently not obligated parties, the data also indicates that these non-obligated "position holders" are responsible for a very small volume of the gasoline and diesel sold at terminals (see further discussion in Sections IV.A and IV.B). Therefore, in light of the considerable biodiesel blending that occurs downstream from terminals, it is reasonable to assume that the gasoline and diesel sold at terminals is by parties that are generally "RIN-short" with respect to biomass-based diesel RINs.

expensive compliance option. If instead unobligated blenders are able to block the installation of the necessary infrastructure to blend biodiesel at terminals, it seems unlikely that changing the point of obligation will cause the large downstream blenders to abandon their presumably profitable downstream blending operations in favor of participating in infrastructure investments at the rack.

Even if changing the point of obligation were to increase biodiesel blending infrastructure at terminals, the benefits to domestic biodiesel producers that Mr. Jobe claims would result seem highly unlikely. Additional blending infrastructure at terminals would not cause biodiesel blenders to suddenly purchase higher volumes of domestic biodiesel if imported biodiesel continues to be available at lower prices. Demand for biodiesel is much more likely to be impacted by the price of biodiesel (relative to petroleum based diesel) than the availability of blending infrastructure at terminals. As long as significant volumes of low cost imported biodiesel are available we anticipate imported biodiesel will preferentially be purchased and blended over higher priced domestic product, particularly near large ports. In this scenario, obligated parties that sell significant volumes of fuel in the interior of the United States would likely purchase separated RINs to meet their compliance obligations, rather than purchasing and blending relatively high cost domestic biodiesel.

Based on the above information, it appears that renewable fuels and renewable fuel blends are currently widely available across the United States. Ethanol is available at all or nearly all terminals and while much of the blending infrastructure may not currently be optimized to produce higher level ethanol blends, it is capable of such optimization. Biodiesel blending infrastructure is more varied, with many terminals having blending infrastructure on-site, some receiving pre-blended biodiesel, and much biodiesel being blended downstream of terminals. Where biodiesel blending infrastructure does not exist we believe it is primarily the result of the higher expense associated with transporting biodiesel to locations with limited or no local biodiesel production.

In any case, we do not believe that the lack of proper incentives to expand blending infrastructure is a primary factor limiting the production or use of renewable fuels in the transportation sector. While blending infrastructure is not universal at all terminals, the primary issues limiting the production and use of renewable fuels are the status of the production technologies to economically produce cellulosic fuels and to a lesser degree the limited consumer demand for higher level ethanol blends.[151] Given the observed sufficiency of blending infrastructure, and the apparent ability of the current regulatory program to incentivize installation of blending infrastructure (whether at or downstream of fuel terminals), the record before us does not support the allegations of petitioners that changing the point of obligation would result in increased use of renewable fuels in the United States as a result of additional incentives or motivation for the installation of blending infrastructure.

[151] While low consumer demand for higher level ethanol blends did not require the use of EPA's general waiver authority to reduce the implied statutory volume of conventional biofuel in 2017, or in EPA's proposed rule for 2018, low demand for these fuels could theoretically result in higher RIN prices than would be realized if consumer demand for these fuels were greater. However, as discussed throughout this document, the record before EPA does not demonstrate that changing the point of obligation is likely to result in greater sales volumes of higher level ethanol blends.

C. Changing the Point of Obligation Is Not Expected to Significantly Impact the Retail Pricing of Fuel Blends with High Renewable Content

One of the factors that could affect the expansion of renewable fuel use in the United States, identified both by the EPA in prior actions and by the parties requesting a change to the point of obligation, is the retail pricing of fuel blends that contain higher concentrations of renewable fuel, such as E85.[152] This is primarily an issue for fuels blended with ethanol. Biodiesel blends tend to be offered at a discount to petroleum based diesel fuel and this discount, which is significantly enabled by the value of the RINs associated with the biodiesel and the biodiesel blenders' tax credit,[153] is regularly large enough to offset the very small impacts that biodiesel blends have on fuel economy. Retailers have often noted the ability to offer biodiesel blends at a discount to petroleum diesel fuel, and the consumer demand for lower priced biodiesel blends, as a primary reason for offering these fuels for retail sale.[154] The relatively high degree of competition among diesel fuel retailers and favorable pricing for biodiesel blends, together with the RFS mandates, are contributing to increasing demand for biodiesel blends and growth in biodiesel production, distribution, and use well beyond the statutory volumes. Consequently, available evidence strongly suggests that the RFS program, in conjunction with other incentives for biodiesel, have been very effective in increasing the supply of biodiesel.

The current retail availability and pricing for E85, however, is significantly different. E85 is currently offered for sale at approximately 3200 stations across the United States (approximately 2% of all retail fuel stations).[155] The low energy density of E85, relative to E10, means that consumers must purchase a significantly greater volume of E85 than E10, and refill their fuel tanks more frequently, to travel the same distance. While some individual stations have offered E85 at a price that more than accounts for the difference in energy density between E85 and E10, this favorable pricing is not generally applicable across the United States.[156] This is despite the fact that in 2015 the relative prices of gasoline blendstocks, ethanol, and D6 RINs, as well as the limited wholesale E85 pricing information available, suggested that E85 could be offered at a price discount greater than the energy content difference between E85 and E10.[157] In a supporting document for the final rule establishing the RFS percentage standards for 2014-2016,

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[152] As discussed in Section II.A, the EPA believes that at this time the primary factor constraining attainment of the statutory volume targets is the shortfall in cellulosic biofuel production. EPA did not base the reduced volumes used in establishing the 2017 RFS standards, or the proposed 2018 RFS standards, on any perceived limitation in the ability to distribute or sell E85, and at this time we have no basis for expecting that this limitation would impact future waiver decisions. However, if changing the point of obligation were to lead to the market selling greater volumes of higher level ethanol blends (such as E85 or E15) at lower prices this could potentially reduce the price of D6 RINs, which is perceived by the petitioners as advantageous.

[153] The $1/gallon biodiesel blenders tax credit has been available every year from 2010-2016 (in some years the tax credit was reinstated retroactively). Currently, this tax credit is not available for 2017.

[154] Letter from Pilot Flying J to Administrator McCarthy, August 16, 2016.

[155] E85 station count from the U.S. Department of Energy Alternative Fuels Data Center Alternative Fueling Station Locator. Available online at http://www.afdc.energy.gov/locator/stations/

[156] See E85 pricing information available at E85prices.com. E85 generally requires a minimum 22% price discount relative to E10 to be an equal cost fuel for consumers on a cost per mile traveled basis.

[157] See discussion in the final rule establishing the RFS standards for 2014-2016 (80 FR 77,420, Dec., 14, 2015).

the EPA examined the potential for higher RFS standards, and the higher RIN prices that could be expected as a result of higher standards, to incentivize lower E85 retail prices and higher sales volumes.[158] In this document we concluded that a lack of competition among E85 retail stations limited the ability for RIN prices to effectively impact retail E85 prices, ultimately limiting the ability of the RFS standards to incentivize a significantly greater supply of E85 to consumers in the near term.

In their requests to change the point of obligation of the RFS program, the petitioners argue that if the EPA changed the point of obligation the RFS standards would have a greater ability to impact the retail price of E85 and incentivize greater use of this fuel. In comments, petitioners and others suggested that obligating downstream parties like "position holders," and increasing obligations for currently RIN-long parties, could result in more price discounting. We find no basis for the claim that changing the point of obligation would have this effect, nor did commenters submit any data that would support this conclusion. Rather we believe changing the point of obligation would be unlikely to impact the retail pricing of E85. We believe the primary factors inhibiting the RFS program from significantly increasing the supply of E85 to consumers are the limited number of retail stations selling E85 and the relative pricing of E85 versus E10. Further, we believe that the generally non-competitive pricing of E85 at retail is not due to the pricing of E85 at the wholesale level, but is instead the result of the non-competitive retail market for E85. This non-competitive market often results in a not unexpected E85 pricing strategy by retail stations that seeks to maximize fuel margins through withholding RIN value and leading to greater profitability, rather than a strategy that seeks to maximize sales volumes through lower retail prices by passing a greater portion of the RIN value through to consumers. Changing the point of obligation to renewable fuel blenders or "position holders" at the rack is not expected to affect these underlying market fundamentals at retail stations.[159]

One of the arguments made by the petitioners, in their petitions and in comments, for changing the point of obligation in the RFS program is that the current point of obligation creates a dis-incentive for parties with excess RINs (un-obligated blenders and parties that sell more gasoline and diesel fuel blended with renewable fuel than they refine or import) to increase the use of renewable fuels by offering fuel blends with high renewable content at attractive pricing. They argue that because these parties profit from selling RINs they are incentivized to keep the RIN prices as high as possible by restricting the blending of additional renewable fuel and/or pricing fuels with higher renewable content such as E85 at levels that are unattractive to consumers, thereby restricting the supply of RINs. According to the petitioners, if the EPA were to change the point of obligation in such a way that RFS obligations were proportional to the volume of gasoline and diesel fuel that a party blends with renewable fuel and/or sells at the rack, rather than the volume of gasoline and diesel a party refines or imports, these parties would have a greater incentive to pass the RIN value through to retail station owners, who would then pass the value on to E85 consumers, ultimately reducing the retail price of E85 and increasing E85 sales.

[158] "An Assessment of the Impact of RIN Prices on the Retail Price of E85," Dallas Burkholder, Office of Transportation and Air Quality, US EPA. November 2015.
[159] Even if EPA changed the point of obligation to "position holders" retail station owners would generally not be obligated parties, and thus the change is unlikely to directly impact retail fuel pricing decisions.

The EPA believes this argument is flawed. Because parties that blend renewable fuels or sell fuel at the rack cannot dictate the retail price of the fuels they sell (unless they also own the retail stations), changing the point of obligation of the RFS program would only be expected to directly impact the wholesale pricing of fuels such as E15 and E85. While some of the parties (blenders or position holders) that would become obligated if the EPA were to change the point of obligation as suggested in the petitions own retail stations, many do not. Parties that do not own retail stations, or own very few, primarily impact the retail price of E85, or any fuel, through the prices at which they offer the fuel at the wholesale level. Wholesale pricing data for E85 are currently very limited. However, what information is available, such as the wholesale E85 pricing published by the Iowa Renewable Fuels Association, shows that in Iowa the wholesale price of E85 already largely reflects the discount enabled by the RIN value associated with this fuel (See Figures 2 and 3 below for wholesale pricing for E85 and E10 in Iowa).[160] This is consistent with letters EPA has received from fuel blenders who told the EPA that it is their practice to price all the fuel they sell at the wholesale level, including E85, at a level that reflects the discount enabled by the RIN value in an effort to offer competitively priced fuel.[161] The petitioners and commenters did not provide compelling evidence to suggest that a significant portion of the RIN value was being withheld by the wholesale providers of E85. If the RIN value is already being largely reflected in the wholesale price of E85, changing the point of obligation to parties that determine the wholesale pricing of E85 would not be expected to result in improved pricing of E85 at the wholesale level.

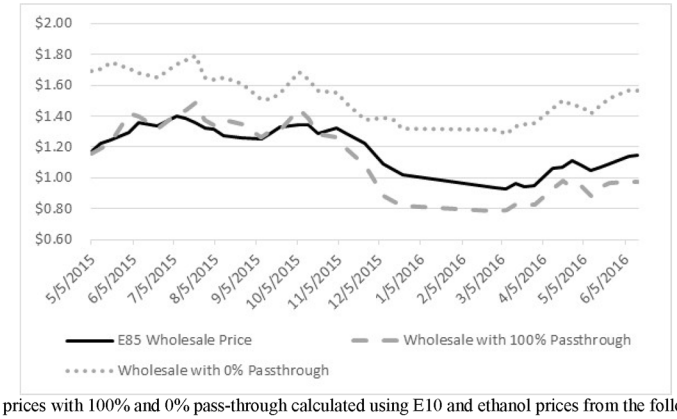
Even if changing the point of obligation as requested by the petitioners were to result in improved pricing of E85 at the wholesale level, we believe it is highly uncertain that this would result in improved pricing at the retail level. If pricing for E85 at retail stations does not improve, the constraint on E85 supply to consumers attributable to retail pricing will not be remedied, hindering the likelihood that sales volumes of E85 will increase significantly. The majority of retail stations (56.6%) are owned by parties who own only a single store.[162] These parties rarely, if ever, blend their own fuel or purchase fuel above the rack and therefore will not become obligated parties even if the point of obligation is changed as requested by the petitioners. They would therefore have no more of an incentive to offer E85 at discounted pricing than they do currently. Information reviewed by the EPA for the state of Iowa shows that even in situations where E85 is available at a significant discount to E10 at the wholesale level, the retail pricing of E85 does not reflect this discount.

The data on wholesale and retail pricing of E85 in Iowa, shown in Figures 2 and 3 below, strongly suggest that the relatively small observed discount for E85 relative to E10 at the retail level is not a result of there being a small discount between these fuels at the wholesale level, and would not necessarily be expected to be improved by changing the point of obligation. The average retail price discount for E85 relative to E10 in Iowa was very similar to the national average retail price discount. The average discount for E85 relative to E10 in Iowa at the retail

[160] This finding conflicts with the paper prepared by NERA on behalf of Valero (Effects of Moving the Compliance Obligation under RFS2 to Suppliers of Finished Products), however we note that NERA provides no data to support their claim that the value of the RIN is not reflected in the wholesale price of E85. Instead, they simply refer to the fact that the full value of the RIN is not reflected in the *retail* price of E85.
[161] See Letter from Tim Columbus to Administrator McCarthy, August 15, 2016; Letter from QuikTrip to Administrator McCarthy, August 17, 2016; Letter from RaceTrac to Administrator McCarthy, August 17, 2016.
[162] http://www.nacsonline.com/YourBusiness/FuelsReports/GasPrices_2013/Pages/WhoSellsGas.aspx

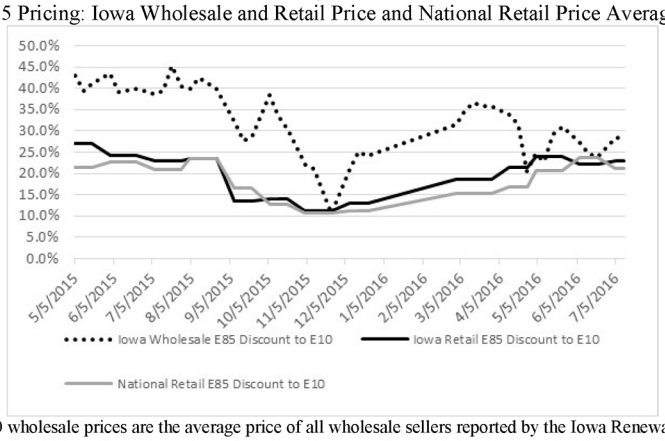
level, however, was much smaller than the average discount for E85 relative to E10 at the wholesale level (See Figure 3 below). Further, the average retail price discount for E85 was less than the discount needed to make up for the lower energy content per gallon of E85 relative to E10 (approximately 22%) during much of this time period. If the wholesale E85 pricing data collected in Iowa are representative of the wholesale pricing for E85 nationwide, which we believe is likely, then the wholesale prices for E85 already reflect the majority of the RIN value and there is very little to no additional RIN value to be passed through at the wholesale level. Even if the nationwide wholesale E85 pricing generally does not reflect the RIN value, and changing the point of obligation could improve the pricing of E85 at wholesale, the data collected from Iowa suggest that significant discounts at the wholesale level would not necessarily be expected to be passed on to the retail level. The available data further support the view that changing the point of obligation in the RFS program is unlikely to result in a greater portion of the RIN value being reflected in the wholesale price of E85, and ultimately the retail price of E85, and will not be an effective mechanism for increasing E85 sales volumes.

Figure 2
Observed vs. Theoretical E85 Wholesale Price in Iowa



Wholesale prices with 100% and 0% pass-through calculated using E10 and ethanol prices from the following sources and assuming the effective ethanol price is discounted by 100% and 0% of the RIN value respectively
E85 and E10 wholesale prices are the average price of all wholesale sellers reported by the Iowa Renewable Fuel Association (Available online at http://iowarfa.org/retailer-center/iowa-wholesale-e85-price-listing-services/)
Ethanol price from Agricultural Marketing Resource Center (http://www.agmrc.org/renewable-energy/ethanol/midwest-ethanol-cash-prices-basis-data-and-charts-for-selected-states/)
RIN Prices from OPIS and Argus Media

Figure 3
E85 Pricing: Iowa Wholesale and Retail Price and National Retail Price Averages



E85 and E10 wholesale prices are the average price of all wholesale sellers reported by the Iowa Renewable Fuel Association (Available online at http://iowarfa.org/retailer-center/iowa-wholesale-e85-price-listing-services/) National and Iowa E10 and E85 average prices (used to calculated the national and Iowa discounts for E85 relative to E10) obtained from E85prices.com

Further, the petitioners rely on a faulty assumption when they argue that un-obligated blenders are incentivized to restrict RIN availability (by restricting renewable fuel blending) in an effort to keep RIN prices high. They assume that the overall price of RINs could be significantly reduced as a result of the increase in the supply of RINs that they claim would result from a greater proportion of the discount enabled by the RIN value being reflected in the retail price of E85.[163] The petitioners provide insufficient evidence to support this argument. In fact, some of the comments that EPA received supporting a change to the point of obligation concede that the market for ethanol is highly inelastic due to the limited demand for E85 and other higher level ethanol blends.[164] The EPA estimates that total E85 sales were approximately 150 million gallons in 2014. In our final rule establishing the RVOs for 2014-2016, the EPA estimated, based on available E85 price and sales volume data, that even if E85 were to be sold at retail at a 50% discount to E10 on a nationwide level, a discount more than twice the current national average, E85 sales would still be expected to remain low, just under 300 million gallons.[165]

Even if we assume an optimistic scenario, that if parties that are able to acquire excess RINs with the current point of obligation were able to double E85 sales to 300 million gallons per year by passing through a greater proportion of the RIN value, this would represent an opportunity to

[163] In this section EPA has primarily focused on E85, rather than other ethanol blends such as E15 or E30. This is in response to the petitions we have received, which generally focus on E85. Further, there is much more market experience with E85, relative to E15 or E30, better allowing for the types of analyses shown here.
[164] For example, see comments submitted by NATSO, EPA-HQ-OAR-2016-0544-0282; Chevron, EPA-HQ-OAR-2016-0544-0209
[165] 80 FR 77,420 (Dec., 14, 2015).

generate an additional 110 million RINs per year,[166] or approximately one half of one percent of the total number of RINs generated in 2016. We believe this number provides a perspective on the likelihood that the additional RINs that might be able to be generated by additional sales of E85 would significantly reduce the overall price of RINs. Additionally, in 2016 approximately 240 million D6 RINs were supplied from grandfathered biodiesel and renewable diesel.[167] It is very likely that these were the marginal cost D6 RINs as the RIN price associated with these fuels is governed by the high price of feedstocks used to produce these fuels relative to petroleum. Even if additional RINs could be generated by supplying greater volumes of E85, these additional RINs would only be expected to appreciably reduce the D6 RIN price after displacing these marginal conventional biodiesel and renewable diesel RINs. Since petitioners and commenters provide insufficient information to demonstrate that changing the point of obligation would result in enough additional low cost D6 RINs to displace the high cost D6 RINs currently provided by conventional biodiesel and renewable diesel, the claim that potential additional RINs generated from increased E85 blending would depress the overall D6 RIN price is unsupported.

If any additional RINs supplied to the market through increased sales volumes of E85 are not expected to significantly reduce the market price of RINs, then any parties that profit from E85 and/or RIN sales would maximize their profit by selling as much E85 (and the associated RINs) as possible. This appears to be the case in the current marketplace; parties currently separating RINs in excess of their RFS obligations are seeking to acquire as many RINs as possible as long as the cost of doing so is less than the value they can recover through the sale of the RIN. Although the EPA does not believe that RIN sales by un-obligated blenders lead to windfall profits, to the extent petitioners believe otherwise their own logic would suggest that these parties should currently be incentivized to undertake efforts to increase the sale of renewable fuel blends to increase the number of RINs sold at a profit. If this were the case, changing the point of obligation to blenders could therefore reduce such sales, since blenders would retain RINs for compliance, thereby removing an incentive for them to increase renewable fuel sales and profits.

In summary, the EPA does not find the arguments made by the petitioners compelling, as they do not address what we believe to be the fundamental challenges to significantly increasing the use of renewable fuels in the near term. As discussed in previous sections, the evidence available to the EPA does not indicate that changing the point of obligation would result in greater availability or price discounts for cellulosic biofuels or biodiesel blends. With respect to higher level ethanol blends, supply of E85 to consumers is currently inhibited by the number of retail stations selling E85, the geographic distribution of these stations, and the relative pricing of E85 versus E10 at the retail level. For the reasons discussed in this section, it appears highly unlikely that changing the point of obligation would influence the relative pricing of E85 versus E10. In the next section, we discuss why the EPA does not believe that data support the position that changing the point of obligation would increase the availability of E85 at retail stations.

[166] An additional 150 million gallons of E85 contain approximately 110 million gallons of ethanol (assuming an average ethanol content of 74% for E85) and would therefore generate approximately 110 million RINs.
[167] See *2016 RIN Supply*.

D. Changing the Point of Obligation Is Not Expected to Significantly Impact the Availability to Consumers of Fuel Blends with Higher Renewable Content

In requesting that EPA change the point of obligation in the RFS program, some parties argue that this would result in an increase in the number of retail stations offering higher level blends of renewable fuel such as E85. They generally argue that the renewable fuel blenders and/or "position holders" have greater influence over the decisions made by the retail station owners, either through direct ownership or through contractual relationships. The petitioners and others argue that if the EPA were to place the point of obligation on the blenders or "position holders," they would use their influence with their retail partners to increase the number of stations offering fuel blends such as E85 in an effort to increase their access to the RINs needed for compliance.

While this argument is generally consistent with the principle that the closer the point of regulation is to the party whose behavior the regulation is intended to impact (in this case the retail station owner) the more effective the regulation is, in this case it ignores the complicated relationships that exist in the fuels marketplace as well as observations from the current marketers of E85. Currently less than 0.5% of all fueling stations are owned by a major oil company, while approximately 50% are branded stations, selling fuel under the brand of a refiner.[168] It is unlikely that blenders and "position holders" would be more effective at encouraging retail stations to offer E85 than the refiners and importers of gasoline and diesel fuel who are affiliated with these stations. This is especially true for the nearly 60% of retail stations owned by single-store owners who are likely to face difficulties raising the capital required to install the equipment necessary to enable the sale of these fuels.[169]

The EPA also assessed the current affiliation of stations selling E85 in the proposed denial. The EPA received several comments on that assessment, including one that provided an updated assessment of E85 station affiliation information. EPA has used the information provided in that comment in the revised assessment presented below.[170]

Using the information presented in the comments, we find that of the approximately 3200 stations selling E85 in the United States at the end of 2016, approximately 40% of them were branded stations (stations affiliated with a refiner) despite the fact that approximately 50% of all retail fuel stations are branded. Conversely, approximately 47% of all stations selling E85 were not affiliated with an obligated party, 10% were private stations or stations owned by a federal, state, or local organization,[171] and 3% were unable to be categorized.[172] Large retail chains, such as Casey's General Stores, Kwik Trip, and Murphy USA, as well as other unbranded stations are

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[168] http://www.nacsonline.com/YourBusiness/FuelsReports/GasPrices_2013/Pages/WhoSellsGas.aspx

[169] Ibid.

[170] Letter from Ron Minsk to Sarah Dunham. February 22, 2017. Submitted as an attachment to comments from Valero, EPA-HQ-OAR-2016-0544-0274.

[171] The 10% of E85 stations that were private or owned by a federal, state, or local organization are not included in the 47% of E85 stations not affiliated with an obligated party.

[172] These numbers are based on an assessment of data from AFDC by Ron Minsk, submitted in comments on our proposed denial of the petitions, EPA-HQ-OAR-2016-0544-0145.

not generally obligated parties under the current regulations.[173] These data do not appear to support claims that moving the point of obligation in the RFS program would result in a greater number of stations selling fuels with higher levels of renewable fuel, such as E85. While there are differences of opinion on the degree to which obligated parties can influence whether or not their branded stations offer E85, if it were the case that an RFS obligation made a party more effective in encouraging their affiliated retail stations to offer fuels containing higher levels of renewable fuel such as E85 we would expect that the stations affiliated with parties with an obligation under the current RFS regulations would have proportionally more stations offering E85 than parties who are not affiliated with a party with an RFS obligation. Instead, we find that while 50% of all retail fuel stations are branded (affiliated with a refiner), only 40% of all stations that sell E85 are branded stations.[174] In contrast, large retail chains often directly own retail stations, thus giving them control of the fuel offerings at the stations they own, and a significantly higher proportion of these stations offer E85 relative to branded stations, as shown below; this suggests that the current point of obligation provides significant incentives for these stations to offer E85 under the right market conditions.

Table III.D-1
Retail Fuel Stations and E85 Stations by Affiliation

	Branded Stations (affiliated[175] with obligated parties)	Unbranded Stations (not affiliated with obligated parties); Not including private stations	Private Stations	Uncategorized Stations
All Retail Fuel Stations[176]	50%	50%	Unknown	N/A
E85 Retail Stations	40%	47%	10%	3%

Furthermore, while only 50% of all retail fuel stations are not affiliated with refiners, approximately 57% of all E85 stations are not affiliated with refiners. An unbranded station is therefore approximately 17% more likely to offer E85 for sale than a branded station if we exclude consideration of private unbranded stations.[177] Unbranded station are approximately

[173] Large retail chains could become obligated parties for all or a portion of the petroleum products they sell if the point of obligation were changed to the renewable fuel blender or the "position holder." These parties purchase fuel above or below the rack depending on the logistics and economics of fuel purchasing and renewable fuel blending at various locations. See, e.g., Comments from Casey's General Stores, EPA-HQ-OAR-2016-0544-0268.

[174] This number increases to 46% percent of all E85 stations affiliated with obligated parties (vs.54% of all E85 stations not affiliated with obligated parties) if we consider only public stations

[175] For the purposes of this assessment, EPA has defined a station as affiliated with an obligated party (or a non-obligated party) if they use the party's name for marketing purposes, such as in the name of the station, on the station signage, etc. Affiliated stations may or may not be directly owned by the party with which they are affiliated.

[176] EPA does not have data on the total number of private retail fuel stations in the United States, however it is likely that it is sufficiently small that it does not impact this analysis.

[177] Since the number of branded and unbranded stations are approximately equal, we determined that unbranded stations are approximately 17% more likely to offer E85 than branded stations by dividing the percentage of E85

42% more likely to offer E85 for sale than a branded station if we include private stations in the count of unbranded stations that sell E85.[178] Parties requesting a change in the point of obligation in the RFS program have claimed that such a change would result in an increasing number of retail stations offering E85 for sale. The data does not bear this out, as E85 is offered for sale at a higher rate at unbranded retail fuel stations relative to retail fuel stations that are affiliated with obligated parties. The record before EPA does not contain sufficient evidence to demonstrate that the point of obligation is a significant factor in a retail station's decision whether or not to offer E85.

In his critique of the EPA's assessment of the number of E85 retail stations as branded as compared to unbranded stations presented in the proposed denial, Mr. Minsk argued that in addition to errors in categorization, the comparison presented by the EPA (comparing E85 stations counts at branded vs. unbranded stations) was inappropriate. Mr. Minsk argues that it is more informative to compare the number of E85 retail station affiliated with obligated parties that are "RIN-long" vs. those affiliated with obligated parties that are "RIN-short."[179] Mr. Minsk concludes E85 stations are much more likely at retail station affiliated with RIN-short obligated parties, with E85 offered at 2.7% of all stations affiliated with RIN-short parties (893 out of an estimated total of 31,000 stations), as compared to E85 being offered at 0.9% of all stations affiliated with RIN-long parties (368 out of an estimated 41,000 stations). When focusing only on stations added since 2013, when D6 RIN prices first rose significantly, E85 was added at 460 stations affiliated with RIN-short parties (1.5% of their total of 31,000 stations) while 125 stations affiliated with RIN-long parties added E85 (0.3% of their 41,000 affiliated stations).[180] Mr. Minsk suggests this is evidence that RIN-short parties are more effective at encouraging the availability of E85 at retail stations they are affiliated with, and that moving the point of obligation to the "position holders" (and, if EPA were to set an RVO that effectively requires higher level ethanol blends, thereby eliminating the ability for some parties to obtain the RINs needed for compliance by simply bending 10% ethanol with the gasoline they sell at terminals) would result in more retail stations offering E85, and therefore greater sales volumes of ethanol.

The conclusions reached by Mr. Minsk, however, are not sufficiently supported by the data. First, Mr. Minsk's assessment appears incomplete, as it does not address the majority of the E85

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stations that are unbranded by the percentage of E85 stations that are branded. This calculation was then repeated when including the percentage of private E85 stations with the percentage of unbranded E85 stations.

[178] Some parties have used this information to argue that refiners are actively discouraging the installation of E85 infrastructure at their branded stations in an effort to discourage renewable fuel penetration. In examining the data from AFDC, however, EPA notes that the majority of the E85 stations at unbranded fuel retail stations are owned by large companies, rather than single store owners. We believe that the greater access to capital that the stations owned by large companies have relative to single store owners is likely to be a larger factor in the higher rate of adoption of E85 infrastructure at unbranded stations than any influence by refiners or the RFS point of obligation.

[179] In his paper, Mr. Minsk categorizes obligated parties as RIN-long vs. RIN-short primarily based on the volume of gasoline and diesel the obligated parties produce relative to the estimated volume of fuel sold at their associated retail stations. For more detail, see Letter from Ron Minsk to Sarah Dunham. February 22, 2017. Submitted as an attachment to comments from Valero, EPA-HQ-OAR-2016-0544-0274.

[180] EPA questions Mr. Minsk's focus on stations added since 2013. While it is true that D6 RIN prices rose substantially in this year, it is certainly possible that obligated parties could have anticipated that increasing demand for RINs, and associated higher RIN prices, would result from the rapidly increasing RFS statutory volumes. E85 stations added prior to 2013 therefore may have been in response to expectations of higher demand for RIN (and associated higher RIN prices) in the future.

stations (E85 stations not affiliated with any type of obligated party, and therefore affiliated with parties that are by definition "RIN-long" due to their lack of an RFS obligation) despite the fact that these stations outnumber stations affiliated with obligated parties. EPA further notes that Mr. Minsk does not convincingly address the source of motivation that the "RIN-short" obligated parties may have for encouraging their affiliated stations to offer E85. As discussed above, the potential market for E85 is not sufficient to generate enough RINs to drive down the price of D6 RINs. This is especially true as a high RIN price is currently necessary to incentivize E85 sales, and the D6 RIN price is likely currently determined by the marginal gallon of conventional biofuel which we believe is currently conventional biodiesel rather than ethanol sold as E85. If increasing the number of retail E85 stations is unlikely to result in lower D6 RIN prices it is reasonable to question whether there are other factors, unrelated to whether an E85 station is affiliated with a RIN-long or RIN-short obligated party, that may explain why E85 is more likely to be offered at branded stations affiliated with some obligated parties that others. After reviewing the data EPA concludes that retail stations owned by a large company are much more likely to offer E85 than retail stations owned by a party owning a single, or small number of retail, regardless of whether the station is affiliated with a RIN-long or RIN-short obligated party or if the station is branded or not. We do not find this surprising, as installing E85 infrastructure is a capital intensive project and therefore much more likely to occur at stations with significant access to capital (such as stations owned by large companies) rather than at stations owned by single-station owners. We further conclude that the higher prevalence of E85 stations affiliated with RIN-short parties (vs. RIN long parties) is the result of a higher rate of direct ownership of retail stations among RIN-short obligated parties, rather than a desire by RIN-long obligated parties to restrict the availability of D6 RINs.

The four parties categorized by Mr. Minsk as RIN-long (BP, Chevron, Shell, and Exxon) directly own an estimated total of just 458 stations out of the approximately 41,000 affiliated stations.[181] Conversely, direct ownership of retail stations is more common among the parties characterized by Mr. Minsk as RIN-short. Through its Speedway brand Marathon directly owns 2,730 retail stations, substantially more than all of the RIN-long parties combined.[182] Similarly Western Refining and MAPCO directly own most or all of their affiliated stations.[183] While Valero does not currently own many retail stations, the vast majority of the stations affiliated with Valero that offer E85 are owned by CST, a large company that owns approximately 3,000 retail stations.[184] Additionally, a relatively large number of the stations affiliated with Valero (43 of 107) added E85 prior May 2013 when Valero spun off its retail operations to CST brands, meaning these stations may have been directly owned by Valero at the time they added E85.[185] Altogether, of the 893 E85 stations affiliated with RIN-short obligated parties we estimate that over 500 of these stations are directly owned by a RIN-short obligated party or a large retail brand formerly

[181] NACS. Who sells America's Fuel? Available online at: http://www.nacsonline.com/YourBusiness/FuelsReports/GasPrices_2013/Pages/WhoSellsGas.aspx
[182] https://www.speedway.com/About/ The vast majority of the stations affiliated with Marathon that offer E85 (321 out of 367) are Speedway stations, See *EPA assessment of E85 stations affiliated with Marathon*.
[183] See http://www.wnr.com/about-us and https://www.mapcorewards.com/about/. Based on these websites we estimate that Western Refining owns 429 retail stations (approximately 75% of their total affiliated stations) while MAPCO owns 345 stations (over 95% of their total affiliated stations).
[184] http://www.cstbrands.com/en-us/OurCompany See also *EPA assessment of E85 stations affiliated with Valero*.
[185] See also *EPA assessment of E85 stations affiliated with Valero*.

owned by a RIN-short obligated party.[186] Note that this is a higher number of stations than directly owned by all of the RIN-long parties combined.

Apart from whether a retail station is owned by a large company or a party owning a single or small number of stations, there are other factors that likely influence whether or not stations offer E85. For example, 165 E85 stations affiliated with RIN-Short obligated parties (19% of all the E85 stations affiliated with RIN-short obligated parties) are affiliated with either CENEX (149 stations) or CountryMark (16 stations). Stations affiliated with both CENEX and CountryMark are primarily located in the midwest, which may indicate that they have greater access to low cost E85 (as a result of proximity to many ethanol production plants) or the station owners and/or customers may be more inclined to support E85. Further, while it does not appear that CENEX directly owns any retail stations, CENEX is owned by CHS, a large agricultural cooperative that may be inclined to support the addition of E85 at their affiliated stations in an effort to support their core agricultural business. To the degree that increased E85 sales support ethanol prices, and ultimately corn prices, these benefits would be expected to be realized by CHS.

Based on our analysis of the data, EPA concludes that the most predictive factor for whether or not a retail fuel station offers E85 is whether the retail station is owned by a large company or whether a party the owns only a single or a small number of retail stations. Since Mr. Minsk's study does not control for this factor, or other potentially significant factors such as geography, we do not believe his work provides a sufficient basis for concluding that retail fuel stations affiliated with RIN-short parties are more likely to offer E85 than stations affiliated with RIN-long parties. There is thus insufficient support for the claim that changing the point of obligation would significantly increase the rate of growth of the number of retail stations offering E85. Unless consumer demand for E85 increases significantly, the expansion of E85 availability at retail will likely be minimal, except in cases where grant funding or other incentives are available, and any addition of E85 at retail stations is very likely to be at stations owned by parties with significant access to capital. Changing the point of obligation will not impact any of these factors, and therefore is not expected to result in additional availability of E85 at retail.

Additionally, some commenters suggested that other limitations in the market, including the number of flex fuel vehicles, and liability and infrastructure compatibility surrounding E15 use, are key factors limiting the use of fuel blends with higher renewable content that would not be impacted by changing the point of obligation.[187]

E. The RFS Program Continues to Create a Significant Incentive for Parties to Invest in the Infrastructure Necessary to Enable Growth in the Use of Renewable Fuels

We believe that the RFS as currently structured provides significant incentives for further growth in the production, distribution and use of renewable fuels and, as discussed elsewhere, we do not believe that the incentives for renewable fuel production, distribution, and use would be greater

[186] A total of 568 E85 stations are affiliated with Marathon, Western Refining, MAPCO, and Valero, however not all of these stations appear to be owned by one of the obligated parties (or CST).
[187] See, e.g., Comments from Cumberland Farms, EPA-HQ-OAR-2016-0544-0160; Comments from Tesoro, EPA-HQ-OAR-2016-0544-0244.

if we were to change the point of obligation. The value of the RIN that is generated when renewable fuels are produced allows fuel blends that contain renewable fuels to be sold at lower prices than would otherwise be possible in the absence of the RFS program. Terminal owners and operators, as well as parties that blend renewable fuels downstream of terminals, are already incentivized to invest in blending infrastructure in an effort to offer their customers the lowest cost fuels possible. Retailers are similarly incentivized to invest in the equipment necessary to offer renewable fuel blends to enable them to offer the widest range of fuel choices. In cases where a lack of competition may inhibit the full value of the RIN from being reflected in the retail price of the fuel, the RIN value can instead provide higher profit margins to the retail station owner to offset their investment in expanding renewable fuel infrastructure. This may ultimately result in more competing retail stations investing in the equipment necessary to offer E85, and with the increased competition retail prices for E85 would be expected to decrease (relative to E10) over time.

Some commenters cited to language in the 2014-2016 final rule indicating that high RIN prices would only result in modest increases in volumes of E85 as evidence that RIN prices cannot drive renewable fuel blending.[188] These commenters take this language out of context. In the 2014-2016 final rule, the EPA was attempting to assess the degree to which an annual volume standard could incentivize additional E85 sales in a single year, not the degree to which the RFS program as a whole can incentivize long term investments that could result in increased renewable fuel availability and use. EPA continues to believe that the RIN value is incentivizing investments to increase renewable fuel use.

F. Changing the Point of Obligation Would Not Be Expected to Increase Cellulosic Biofuel Production

While there continue to be challenges related to the distribution and use of renewable fuels in the United States, the largest single challenge to meeting the RFS program's statutory volumes is the shortfall in cellulosic biofuel production. The supply of cellulosic biofuel for 2018 was projected in the 2018 annual rule proposal to be only 3.4% of the statutory volume for these fuels. The importance of cellulosic biofuels to achieving the overall goals of the RFS program only increases in future years, as over 90% of the growth in the statutory volumes from 2018 to 2022 is expected to come from cellulosic biofuel. Changing the point of obligation would not be expected to address the current research, development, and commercialization challenges that will need to be overcome to enable the production of significant volumes of cellulosic biofuel in future years. Instead, to the degree that it reduces the incentive of the refiners to participate in the commercialization of cellulosic biofuels, changing the point of obligation from primarily refiners, who have significant financial resources and experience in commercializing new fuel production technologies on a large scale, to include many smaller downstream parties without such financial resources or experience may negatively impact the ability of the cellulosic

[188] See, e.g., Comments from CVR, EPA-HQ-OAR-2016-0544-0396, citing *Renewable Fuel Standard Program: Standards for 2014, 2015, and 2016 and Biomass-Based Diesel Volume for 2017*, 80 Fed. Reg. 77,420, 77,459 (Dec. 14, 2015).

biofuels industry to overcome these challenges. [189] Additionally, we believe that the uncertainty surrounding the RFS program that would likely result from a change in the point of obligation would discourage potential investors from investing in new cellulosic biofuel production technologies and commercial scale production facilities at a time when a number of cellulosic technologies are nearing commercial-scale production.

Some commenters suggested that by changing the point of obligation to the "position holders" EPA would increase the obligation for large integrated refiners, as most of these parties sell more gasoline and diesel at the rack than they refine or import.[190] These commenters argued that changing the point of obligation to the "position holders" would encourage these large integrated refiners to invest in cellulosic biofuels. Other parties, including large integrated refiners, indicated that an increasing RIN obligation for them would hinder their abilities to invest in cellulosic biofuels. Some parties associated with the renewable fuels industry supported EPA's conclusion that changing the point of obligation to "position holders" could harm investors in cellulosic biofuel production technologies and production facilities close to commercial-scale production.[191] Parties arguing that changing the point of obligation to "position holders" would increase investment in cellulosic biofuel development stated that the large integrated refiners have the necessary resources and are most capable of investing in research and development, but currently have no incentive to invest as they can fulfill their regulatory requirements without using cellulosic biofuel. As support for these statements the commenters compare the revenues of large integrated refiners to those of relatively smaller merchant refiners and the fact that several large integrated refiners are currently engaged in R&D efforts. The EPA does not find the arguments that changing the point of obligation to "position holders" would increase investment in cellulosic biofuel development convincing.

While the EPA acknowledges that large integrated refiners have significant revenues it is not clear why integrated refiners should be expected to invest in cellulosic biofuel development while merchant refiners, many of whom have less but still significant resources, should not.[192] The commenters note that several integrated refiners have recently reduced funding of R&D efforts for cellulosic biofuels. They allege that if these parties had relatively greater RIN obligations they would not have scaled back their investment. However, the EPA notes that these companies began investing in cellulosic biofuel R&D at a time when the RFS obligations were much lower than today. These parties did not suddenly reduce their investments after finding themselves with excess RINs. Rather, as the commenters themselves discuss, they have had excess RINs since the beginning of the RFS program. Indeed, if RIN obligations beyond a company's ability to obtain RINs by blending renewable fuels made a company more likely to invest in cellulosic biofuels, we would expect large merchant refiners such as Valero, Holly Frontier, and PBF Energy, which also have significant resources, to be investing significant sums

[189] See, e.g. Comments from Tesoro, EPA-HQ-OAR-2016-0544-0244, suggesting that a change to the point of obligation could "negatively impact ongoing efforts to spur advanced biofuel production initiatives being pursued by the refining industry." See also Letter from Tesoro, Ensyn, and Honeywell noting their efforts for a path forward for cellulosic biofuel production.

[190] EPA notes that this change would also decrease the RFS obligation of merchant refiners

[191] See, e.g. Comments from BIO, EPA-HQ-OAR-2016-0544-0217.

[192] Valero compares the combined revenue of Chevron and Shell ($197 billion in 2015) to the combined revenues of Valero, Holly Frontier, and PBF Energy ($78 billion in 2015), see EPA-HQ-OAR-2016-0544-0274. EPA believes that any of these companies have sufficient revenue to invest in cellulosic biofuel development if so inclined.

in cellulosic biofuels, yet even the commenters acknowledge this is not the case. It appears it is likely that those integrated refiners that reduced their investment in cellulosic biofuel did so after determining that these investments were unlikely to result in long term profits, or that whatever profits could be realized were less than alternative investment opportunities. Finally, we note that because the cellulosic waiver authority in CAA 211(o)(7)(D) requires that EPA establish the cellulosic biofuel volume requirement at the level projected to be produced (if this volume is lower than the statutory volume) and to make cellulosic waiver credits available as an alternative means of compliance when the statutory volume is not in effect, the design of the RFS program provides limited encouragement for parties of any type to invest in cellulosic biofuels. Obligated parties, like all parties, are only expected to invest in cellulosic biofuel to the degree that they believe these investments will be profitable in the long term. We believe that changing the point of obligation to the "position holders," and thereby placing a greater burden on integrated refiners would be highly unlikely to significantly impact integrated refiner's investments in cellulosic biofuels.[193]

G. Changing the Point of Obligation Would Not Be Expected to Increase Energy Security

As mentioned above, one of the stated goals of EISA and the RFS program is to increase energy security. Many commenters suggested that the EPA should consider how modifying the definition of obligated party could increase energy security and proposed several ways obligating "position holders" may result in increased energy security. These commenters often cited to comments by Commander Kirk S. Lippold, who suggested that the RFS program is harming US energy security.[194] Commander Lippold claims that the current point of obligation threatens the viability of some refiners, increases fuel costs to the military and other domestic consumers, and stimulates demand for foreign biofuels. EPA finds insufficient factual basis for these claims.

Some commenters suggested that the reason the U.S. has become a net exporter of petroleum fuel in recent years is that obligated parties were exporting fuels to avoid the RIN obligation. Some of these commenters conceded that the RFS played only some part in this, however others attributed the export of petroleum fuel to the RFS program. We do not believe these statements to be accurate, as the decision to export gasoline and diesel from the United States is driven by a desire to realize the maximum profits for these products in the global refined product market. There are no fuel shortages within the United States, so the exported fuel is not being exported at the expense of domestic use, but to find a market offering higher prices for these fuels than the domestic market. (See also Section II.E. for a further discussion of this issue). Changing the point of obligation to "position holders" would not alter these fundamental market dynamics,

[193] Some commenters suggested that changing the point of obligation could also increase development and investment in advanced biofuel production and use. These commenters did not provide any reasons why a change would result in these increases, and therefore EPA does not find these arguments compelling for similar reasons expressed above regarding cellulosic biofuel. See, e.g., Comments from CVR Energy, EPA-HQ-OAR-2016-0544-0396. In fact, EPA received comments suggesting that a change to the point of obligation would negatively impact ongoing efforts to increase advanced biofuel production. See Comments from Tesoro, EPA-HQ-OAR-2016-0544-0244.

[194] Letter from Cdr. Kirk S. Lippold, to U.S.EPA, EPA-HQ-OAR-2016-0544-0143.

sand therefore would be unlikely to increase the energy security of the United States by decreasing the amount of exports of petroleum fuel.

Other commenters suggested that the current point of obligation would cause refineries to close, with some specifying that merchant refineries would be the most likely to close as a result of the RFS program. Commenters claimed that such closures would threaten American energy independence and national security. They stated that closure of northeast refineries would exacerbate dependence on foreign energy sources and could lead to price spikes in fuel. Commenters also suggested that increasing petroleum prices could harm the Department of Defense and other agencies.

Whether produced by domestic refiners (e.g., Northeast refineries) or imported into the U.S., gasoline and diesel fuel bear the exact same RIN obligation. Thus, there can be no incentive provided by the RFS program for greater dependence on foreign energy sources. Furthermore, The EPA disagrees that the current point of obligation is likely to cause refinery closures, for merchant refiners or any other refiners. Data reviewed by EPA demonstrates that refiners recover the cost of the RIN through higher prices for their petroleum products as discussed in section II.C. However, to further assess whether or not the RFS program, and specifically high RIN prices, might be causing refinery closures EPA examined publicly available data from the Energy Information Administration on refinery closures, deratings, and expansions from 2013 to 2017. We chose these years for our assessment, as this time period corresponds to the years with elevated D6 RIN prices. If the RFS program were causing refinery closures through high RIN prices, they would have been most likely to occur during these years. In its refinery capacity report, the Energy Information Administration (EIA) publishes a list of U.S. refinery shutdowns.[195] The list of refinery closures since 2013 is provided in Table III.G-1 below. As a point of reference, in 2013 there were 143 operable refineries with a total atmospheric crude distillation capacity[196] of 18,560,000 barrels per day in 2013.

[195] Table 13 Refineries Permanently Shutdown by PAD District Between January 1, 1990 and January 1, 2017 https://www.eia.gov/petroleum/refinerycapacity/table13.pdf

[196] Total Atmospheric Crude Distillation Capacity is the most commonly used measure of the capacity of a refinery.

Table III.G-1
Refinery Closures (2013-2017)

Company Name	Location	Date of Shutdown	Total Atmospheric Crude Distillation Capacity (bbl/cd)	Asphalt Plant
Hess Corporation	Port Reading, NJ	3/2013	0	No
Axeon Specialty Products LLC	Savannah, GA	12/2014	28,000	Yes
Ventura Refining and Transmission LLC	Thomas, OK	11/2014	12,000	No
Trigeant LTD	Corpus Christi, TX	12/2014	0	Yes
Pelican Refining Company LLC	Lake Charles, LA	1/2015	0	Yes
Antelope Refining LLC	Douglas, WY	12/2016	3800	Yes
Flint Hills Resources LP	North Pole, AK	6/2014	126,535	No

A review of the list of refinery closures that occurred between 2013 and 2017 does not provide a compelling case for hardship caused by the RFS program. Four of the seven refineries are asphalt refineries which do not produce transportation fuels and are therefore not affected by the RFS program. The Flint Hills refinery is located in Alaska, which is exempt from the RFS program. According to a journal article covering the Hess refinery closure, the Hess management attributed the refinery closure to dwindling demand on the East Coast along with heating oil sulfur standards which were phasing in there.[197] The last refinery on the list of refinery closures is the Ventura refinery in Thomas, OK. Reviewing the gasoline production information provided by this company to EPA does not show that the Ventura refinery produced gasoline when this refinery was operating, although the refinery may still have had to comply with RFS program if the refinery produced diesel fuel.[198]

While there were very few refinery closures from 2013-2017 (and only one small refinery for which the available information is insufficient to discount attribution to the RFS program), refineries added additional capacity at their refineries. Between 2013 and 2017, the EIA data shows that the U.S. refining industry increased its atmospheric crude oil throughput capacity from about 19 million barrels per stream-day to 19.8 million bbl/stream-day, an increase of more than 4%. [199] A portion of this change in crude oil distillation capacity was for condensate

[197] Bell, Deborah; Hess Port Reading Refinery to Permanently Close Next Month, Woodbridge Patch, January 28, 2013. Available Online: https://patch.com/new-jersey/woodbridge/hess-port-reading-refinery-to-permanently-close-next-month.

[198] EPA conducted an analysis looking farther back in time in the draft regulatory impact analysis supporting the proposed Tier 3 emission standards, EPA-420-D-13-002, March 2013. Refineries closed at a far greater rate in years past. For comparison 102 refineries closed over the decade from 1982-1992, 46 from 1992-2002, and 2 from 2002 to 2012.

[199] Table 6 Operable Production Capacity of Petroleum Refineries, January 1, 1988 to January 1, 2017 https://www.eia.gov/petroleum/refinerycapacity/table6.pdf

splitting and for asphalt plants which do not produce finished fuels and therefore would not be affected by the RFS program. To focus our analysis more directly on refineries affected by the RFS program, we reviewed changes in individual refinery operable atmospheric crude oil capacity from 2013 to 2017.[200] [201] The results of our assessment (as shown in Table III.G-2 below) show that from 2013 to 2017 refinery expansions outnumbered closures 39 to 4, and atmospheric crude capacity increases were more than 25 times the reductions. Note that this table does not include any added capacity for condensate splitters, any expansion or contraction at asphalt plants, or any expansion or contraction of refineries located in Alaska.

[200] Refinery capacity data by individual refinery as of January 1, 2013; Available Online at https://www.eia.gov/petroleum/refinerycapacity/archive/2013/refcap2013.php
[201] Refinery capacity data by individual refinery as of January 1, 2017; Available Online at https://www.eia.gov/petroleum/refinerycapacity/

Table III.G-2
Refinery Expansions, Closures, and Derating (2013-2017)
Million Barrels per Stream-Day

Refinery Name	Expansions	Closures/Derating	Net Expansion
ALON USA ENERGY INC	4,000	0	4,000
AMERICAN REFINING GROUP INC	1,300	0	1,300
BIG WEST OIL CO	3,000	0	3,000
BP	4,000	0	4,000
CALCASIEU REFINING CO	25,000	0	25,000
CALUMET	36,000	0	36,000
Chalmette Refining LLC	2,000	0	2,000
CHEVRON	17,000	0	17,000
CHS MCPHERSON REFINERY INC	9,500	0	9,500
CITGO REFINING	0	1,500	-1,500
COUNTRYMARK COOPERATIVE INC	2,600	0	2,600
DELEK REFINING LTD	10,000	0	10,000
ERGON	3,300	0	3,300
EXXONMOBIL	31,000	0	31,000
Flint Hills Resources LP	30,000	0	30,000
HERMES CONSOLIDATED LLC	4,000	0	4,000
HOLLYFRONTIER	27,020	0	27,020
HOUSTON REFINING	0	6,000	-6,000
LIMA REFINING COMPANY	15,000	0	15,000
MARATHON	120,500	0	120,500
MONROE ENERGY LLC	18,000	0	18,000
Motiva	20,000	0	20,000
PASADENA REFINING SYSTEMS INC	9,200	0	9,200
PDV Midwest Refining LLC	5,200	0	5,200
PHILADELPHIA ENERGY SOLUTIONS	0	5,000	-5,000
PHILLIPS 66	31,156	0	31,156
PLACID REFINING CO	23,500	0	23,500
PREMCOR REFINING GROUP INC	5,000	0	5,000
SHELL CHEMICAL LP	10,500	0	10,500
Silver Eagle Refining	100	0	100
SINCLAIR WYOMING REFINING CO	5,000	0	5,000
ST PAUL PARK REFINING CO LLC	19,200	0	19,200
SUNCOR ENERGY (USA) INC	500	0	500
TESORO	27,600	0	27,600
TOLEDO REFINING CO LLC	13,000	0	13,000
TORRANCE REFINING CO LLC	2,000	0	2,000
VALERO	276,500	18,000	258,500
VENTURA REFINING & TRANSMISSION	0	14,000	-14,000
WESTERN REFINING	5,000	0	5,000
WRB REFINING LP	3,000	0	3,000
TOTAL	819,676	44,500	775,176

The review of the individual refinery atmospheric crude capacity changes from 2013 to 2017 does not indicate hardship on the part of the US refining industry, and in fact, suggests that the market conditions in this time period promoted growth. Refiners are generally making investments in their refineries to expand their throughput capacity, suggesting that the US

refining industry is growing and healthy. Furthermore, the refineries which expanded their atmospheric crude oil capacity included small, medium and large refineries, as well as both integrated and merchant refiners. Aggregate refinery expansions totaled about 820 thousand barrels per stream-day (kbbl/stream-day), but is offset by 31 kbbl/stream-day of refinery closures and modest derating, for a total of 789 kbbl/stream-day of added throughput capacity (excluding condensate splitters, asphalt plants, and refineries located in Alaska).

IV. Changing the Point of Obligation Would Significantly Increase the Complexity of the RFS Program

In order to minimize the number of regulated parties and reduce programmatic complexity, the EPA in the RFS1 regulations placed the RFS point of obligation on the relatively small number of refiners and importers rather than on the relatively large number of downstream blenders. We noted then that the designation of downstream ethanol blenders as obligated parties would have greatly expanded the number of regulated parties and increased the complexity of the RFS program unnecessarily.[202] The same is true now. For example, consider the current point of obligation: refiners and importers. Identifying on a continuing basis those entities who produce or import gasoline and diesel fuel is relatively straightforward, as their businesses tend to operate from fixed physical locations that change infrequently, and ownership of the companies and assets also change relatively infrequently. In addition, identification and tracking of these entities is facilitated by our regulation of them under other (non-RFS) regulatory programs. However, the situation "downstream" of refiners and importers becomes much more complicated. There are a wide variety and large number of market participants, business practices, and contract mechanisms downstream of refiners and importers, and the parties, practices, and ownerships among entities downstream of refiners and importers are much more variable over time. All of these factors would make imposition of the RFS point of obligation on some subset (e.g. blenders or "position holders") of parties downstream of refiners and importers substantially more complex than the current system.

In the RFS2 proposal, we requested comment on whether the EPA should move the obligation downstream of refineries and importers to those parties who blend and supply finished transportation fuels to retail outlets or to wholesale purchaser-consumer facilities. In response to the proposal, stakeholders differed significantly. A few refiners, including Valero, expressed support for moving the obligations to downstream parties, while other refiners preferred to maintain the current approach. Blenders and other downstream parties generally expressed opposition to a change, citing the additional burden of demonstrating compliance with the standards, especially for small businesses. They also pointed to the need to implement new systems for determining and reporting compliance, the short lead time for doing so, and the fewer resources that smaller downstream companies have to manage such work in comparison to much larger entities such as refiners. We considered the comments received and concluded based upon the comments and information available to us that it was appropriate to maintain refiners and importers as obligated parties under the amended RFS2 program. In explaining our

[202] 72 Fed. Reg. at 23923.

reasoning, we noted once again that changing the point of obligation would likely result in a significant increase in the number of obligated parties under the program.

Several of the petitions received by the EPA cite text from the 2010 Final Rule acknowledging that one of the initial justifications given for placing the obligation on refiners and importers of gasoline and diesel, rather than on parties that are "downstream" of the refineries, was a desire to minimize the number of regulated parties in the RFS program.[203] As the EPA stated in the 2010 Final Rule and Summary and Analysis of Comments, as a matter of regulatory design and implementation, it is desirable both to limit the number of obligated parties, and to limit burdening small businesses.[204] These considerations favored placing the point of obligation on the limited number of refiners and importers, rather than the larger number of blenders.

Additionally, as the EPA projected in the proposed RFS2 rule, virtually all downstream blenders are currently subject to RFS registration, recordkeeping and reporting requirements associated with their role as RIN owners. The EPA asked in that proposal whether, in light of this fact, it would be difficult administratively to move the obligation to these parties. The petitioners generally argue that moving the point of obligation to downstream parties would not be difficult, since they are already regulated in some fashion. However, while it is likely the case that all, or nearly all downstream blenders are now regulated parties under the RFS program due to the increased blending of renewable fuels required by the RFS program, the majority of these downstream parties are not refiners or importers and therefore are currently not obligated parties under the RFS program. There is a significant distinction between being a "regulated party" and being an "obligated party" under the RFS program.[205]

A. The Number of Obligated Parties Would Increase if the Point of Obligation was shifted to "Position Holders" or "Blenders"

Petitioners generally propose to change the point of obligation to "positions holders" and argue that doing so would involve a similar number of obligated parties or could reduce the number of obligated parties as compared to the number of obligated party refiners and importers that exist today. Petitioners provided EPA with an analysis to support their argument. Petitioners also argue that this proposed change would be relatively easy to implement because the number of

[203] 75 Fed. Reg. 14721 (March 26, 2010).
[204] Ibid.; Renewable Fuel Standard Program (RFS2) Summary and Analysis of Comments, EPA-420-R-10-003 (February 2010), at 3-216.
[205] Downstream blenders who blend renewable fuel into transportation fuel and own RINs at blending must report the quantity of RINs purchased, separated from renewable fuel, and sold according to the reporting requirements under 40 CFR 80.1451(c). They must also register with the EPA under 80.1450 and keep records as required under 80.1454. Small blenders can also shift the compliance burdens if they qualify under 40 CFR 80.1440. Obligated parties must meet all of these requirements and also calculate an annual renewable volume obligation, acquire the appropriate number of RINs in the market, practicing due diligence to ensure their validity, file annual compliance reports demonstrating compliance, and maintain records to that effect.

obligated parties would at least remain relatively the same, if not decrease.[206] But as discussed in more detail below, we believe that Petitioners' suggested change would result in a significant increase in the number of obligated parties. More importantly, we believe that the type of parties Petitioners seek to shift the point of obligation to, and their experience level and available resources indicate that implementing Petitioners' proposed change would result in a less effective RFS program that would be more difficult to implement and enforce.

As discussed above, the EPA believes that all else being equal, placing the point of obligation on a smaller number of obligated parties with significant financial resources and expertise in fuels markets is preferable to placing it on a larger number of relatively small entities. This approach facilitates program effectiveness by limiting the number of entities the EPA must interact with to provide guidance and to ensure compliance. It also places the burden on the larger, more sophisticated entities that are more likely to have the personnel and systems in place to enable compliance.

In the proposed denial, the EPA argued that the number of obligated parties would increase significantly if the point of obligation under the RFS Program were changed from refiners and importers to "position holders" at the rack. We cited our discussions with terminal operators and associations and our own data on oxygenate blenders for reformulated gasoline (RFG) to estimate that the obligated party count would increase from around 150 to between 350 and 1,000. The EPA argued that a higher number of obligated parties, many of whom would have less expertise and fewer resources to provide oversight to the RIN program to help ensure the validity of RINs than the current obligated parties, could result in greater non-compliance and RIN fraud. This could negatively impact the ability of the RFS program to achieve its statutory goals. A larger number of obligated parties would also result in higher compliance monitoring and assistance costs, among other key market and policy concerns.

In its petition, Valero stated that moving the point of obligation to the "position holder" would not increase the obligated parties above 200, based on their extensive knowledge of all players in the fuel blending and sales industry. In its analysis, Valero aggregated all entities to the parent company level to come up with the 200 count. We note that this may not be an "apples to apples" comparison with the number of obligated parties under the current RFS regulations, as not all parties comply with their RFS obligations at the parent company level. EPA attempted to aggregate the list of obligated parties in 2016 to the parent company level to provide a count comparable to Valero's estimate. Based on this assessment there were approximately 97 obligated "parent companies," after aggregating the full list of obligated parties; significantly less than the estimate provided by Valero.[207]

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[206] See Valero Petition for Rulemaking, June 13, 2016, EPA-HQ-OAR-2016-0544-0008, Attachment D and E. See also report by IHS Global Insight, Inc., submitted by Monroe, EPA-HQ-OAR-2016-0554-0368, Attachment J (claimed as CBI).

[207] *RFS 2016 Obligated Parties.* This document contains information claimed as CBI.

During and after the comment period, the EPA engaged with the IRS to obtain more concrete information about the count of "position holders." Since several of the petitioners and commenters suggested changing the point of obligation to the "position holders," this information would allow EPA to determine the number of obligated parties that would result from changing the point of obligation to the "position holders." IRS reviewed the data it maintains on "S" registrants, which is defined by the IRS to include, using their definitions, enterers, position holders, refiners, terminal operators, or throughputters of gasoline, diesel fuel (including a diesel-water fuel emulsion), or kerosene, or industrial users of gasoline.[208] The IRS noted that they cannot identify which type of actor an "S" registrant is (enterer, position holder, refiner, etc.). The EPA notes that, utilizing IRS definitions, refiners (those that break bulk at a refiner gate), position holders (those that break bulk at a terminal), and enterers (those that import fuel through means other than at a terminal such as truck are the actors that would become obligated parties if the point of obligation shifted to "position holders" as proposed by petitioners and as the term is used in this document. Terminal operators and throughputters would not become obligated parties if the point of obligation shifted to "position holders" as proposed by petitioners, as these parties do not hold title to the gasoline or diesel fuel immediately prior to the sale of these fuels at the terminal.[209] If a terminal operator or throughputter "breaks bulk," in a given quarter, they are categorized for that quarter as a position holder or refiner. "S" registrants file Form 720, the Quarterly Federal Excise Tax Return, to report the quantity of fuel they own. EPA requested the number of "S" registrants who paid taxes as owners of gasoline or diesel, to represent the potential number of obligated parties if the point of obligation shifted to "position holders" as proposed by petitioners because the RVO applies to volumes of gasoline and diesel ("S" registrants that do not own any gasoline or diesel in any given year would not pay taxes or have an RFS obligation for that year).

Information received from the IRS included the following:

- For fiscal year 2015, there were 1,571 "S" registrants, of which 715 filed Form 720 tax forms.[210]
- In calendar year 2016, 443 of the Form 720 tax filers paid taxes as owners of gasoline or diesel.[211]
- There is approximately a 30 percent turnover in number of parties that pay taxes as owners of gasoline or diesel from year to year.[212]

[208] The IRS definition of "position holder" is different than how the term is used in this document, and how it is used by petitioners. The IRS definition applies only to parties who hold title to fuel above the terminal rack. Refiners who hold title to fuel above the refinery rack are a separate entity ("refiners") under IRS definitions.
[209] Using IRS terminology, these parties do not "break bulk"
[210] Not all parties that filed a Form 720 tax form paid taxes as owners of gasoline or diesel
[211] Some of the 720 tax filers paid taxes on fuels other than gasoline or diesel, and therefore would not likely become obligated parties if EPA changed the point of obligation to the "position holder"
[212] This estimate of annual turnover was provided to EPA by IRS. It is not calculated using the information in the preceding bullets.

Based on this information, the EPA has concluded that the best estimate for the number of parties that would have been obligated parties in 2016 if EPA changed the point of obligation to the "position holders" is approximately 443. The 30 percent turnover in program participations from year to year implies that the obligated parties could be quite variable year over year. Although the total number of obligated parties would likely be around 450 per year, the EPA would still need to track the parties who may have been obligated in previous years, and account for movements in and out of the RFS program. For example, if 30% of the "position holders" changed from 2016 to 2017, we would expect that there would be a total of approximately 576 parties that were "position holders" over a two year period.[213] Assuming the EPA adopted the approach to reporting currently utilized by the IRS, as suggested by many petitioners and commenters, we would expect approximately 450 obligated parties in any given year along with a large group of parties we would need to consider as "potentially obligated parties" (at least 133[214] based on turnover in a single year, and likely many more) based on their prior year's activities. Since IRS cannot share data on the identity of the Form 720 tax filers nor on the volumes of gasoline or diesel they move over the rack this would cause significant enforcement challenges for EPA, especially as many of these parties would likely be difficult to identify. In calendar year 2016, there were 120 obligated parties under the current RFS regulations;[215] a change to obligate "position holders" would more than double the number of obligated parties. The matter would be even more complex for EPA administration in light of the additional potentially responsible parties whose activities EPA would likely feel obligated to monitor to some degree to verify whether they should be obligated parties in any given year, assuming these parties could be identified. As such, the EPA continues to believe that the obligated party count would increase significantly, and program administration would be considerably more complex, under the petitioners' proposal.

The EPA received several comments that challenged EPA's assertion in the proposed denial that an increase in the number of obligated parties would result in a higher administrative burden on the EPA, in part because it would increase the number of annual compliance reports for the EPA to review every year. While administrative burden is a secondary consideration, relative to achieving the statutory goals of the RFS program, EPA has assessed the claims made by these commenters. One set of comments countered that changing the point of obligation to "position holder" would result in a decrease in the number of RIN transactions because obligated parties would acquire the RINs at blending and retire them without intervening transactions.[216] The argument follows that the EPA would need to verify fewer RIN transactions, thereby decreasing

[213] This is the minimum number of obligated parties that would be expected if EPA changed the point of obligation to the "position holders," assuming a 30% turnover. The actual number of obligated parties would likely be far higher.
[214] 133 is 30% of 443 (the number of "position holders" in 2016)
[215] 40 CFR Part 80 currently allows obligated parties to comply with the RFS requirements at the "facility" level if they so choose, and thus provides for flexibilities for obligated parties to comply as compared to reporting to the IRS. In 2016 the EPA received 191 compliance demonstrations; 93 from aggregated refiners, 59 from individual facilities, and 39 from importers of gasoline or diesel. We note that some of the obligated parties submitted compliance demonstrations as both aggregate refiners and importers of gasoline and diesel.
[216] Comments from Valero Energy Corporation, EPA-HQ-OAR-2016-0544-0274.

administrative burden. The EPA notes that its compliance monitoring and verification costs have little to do with the number of RIN transactions that occur. Rather, the EPA expends the majority of its oversight resources to monitor and provide compliance assistance for registration activities (including updates to registration after an ownership or personnel change), annual compliance report submissions, RIN retirements, and remedial actions for errors that have occurred. The oversight burden of these activities is directly related to the total number of obligated parties and not the total number of RIN transactions. Furthermore, the EPA notes that current obligated parties submit other compliance reports to EPA to meet other Part 80 requirements, and EPA uses these reports to help verify RFS volumes in the annual compliance reports. If the "obligated party" definition changes to "position holder," EPA would no longer be able to utilize this data verification method and would need to develop other verification methods to ensure the integrity of the RFS program.

Another set of comments suggested that compliance costs would not increase with an increase in the number of obligated parties because the EPA could get the list of obligated parties along with their verified gasoline and diesel volumes directly from IRS.[217] In light of these comments, the EPA discussed at length with IRS whether a data sharing agreement could be developed to allow the EPA to obtain this type of detailed IRS data on "position holders." The IRS stated that tax returns and tax return information are confidential and may be disclosed only as authorized under Internal Revenue Code section 6103(a). "Return information" is broadly defined to include any information gathered with regards to a taxpayer's liability under the Code, including a taxpayer's identity. As such, the IRS stated that even a mere list of "position holders" would constitute return information and could not be provided to the EPA without the consent of each "position holder." Therefore, the EPA has concluded that the commenters' argument is incorrect and that EPA would be unable to obtain the information it would need from the IRS to identify the "position holders" and determine their obligated volumes of gasoline and diesel and would instead need to develop its own systems to identify obligated parties and track their obligated fuel volumes.

Some commenters argued that "position holders" would have very little compliance burden as obligated parties because they would simply utilize the measurements, calculations, and records already in place to meet IRS requirements.[218] Likewise, they argued that EPA could simply change its RVOs requirements to equal the volumes reported on Form 720. However, based on a detailed comparison of IRS requirements to RFS requirements, the EPA has concluded that the volumes reported on Form 720 are different than the volumes used to calculate RVOs. Most notably, ethanol and biodiesel that is blended into gasoline and diesel fuel at the terminal upstream of the rack are included in the Form 720 gasoline and diesel volumes, while those biofuels must be excluded from gasoline and diesel volumes used to calculate RVOs. In addition, home heating oil volumes, kerosene, fuel used by ocean going vessels, volumes used in Alaska and the Territories, and volumes that cross a rack a second time are reported on Form 720, while

[217] See, e.g., Comments from CVR Energy, EPA-HQ-OAR-2016-0544-0396; Comments from the Small Refiners Coalition, EPA-HQ-OAR-2016-0544-0406.
[218] Comments from Valero Energy Corporation, EPA-HQ-OAR-2016-0544-0274.

those volumes must be excluded in determining RVOs. Data provided to the EPA by the IRS shows that the total volume on which taxes were paid by "S" registrants in 2016 was about 244 billion gallons. The total gasoline and diesel volumes produced by refiners and importers in 2016 according to the RFS compliance reports submitted by these parties to the EPA was about 180 billion gallons.[219] Therefore, EPA has concluded that obligated parties would not all be able to simply use the Form 720 volumes to calculate their RVOs; a significant number would likely need to take, maintain, and report different measurements than they currently do for IRS compliance purposes. Likewise, the EPA would have to expend significant administrative resources to create regulations, instructions and compliance assurance assistance related to obtaining and verifying the information need for obligated parties to calculate their RVOs.

The Small Refiners' Coalition and CVR Energy suggested that if the EPA could not obligate "position holders" due to concerns about statutory authority, then the EPA could instead obligate all blenders, and that such a change would not add to the complexity of the program or harm small entities.[220] The EPA disagrees with those conclusions – for the reasons articulated above about the additional complexities associated with designating "position holders" as obligated parties, obligating "blenders," which includes many "position holders" and other small entities, would also increase complexity in the RFS program, due to an increased number of obligated parties, and potentially very small entities, including retail station owners. These small entities would have additional obligations and requirements, and although they may currently separate and sell RINs, they do not currently have the same requirements as an obligated party. More importantly, however, as discussed in Section III above, EPA does not believe, based on the information in the record, that changing the point of obligation to downstream parties (either "position holders" or blenders) would result in additional production, distribution or use of renewable fuels.

B. The Potential for Noncompliance May Increase if the Point of Obligation is Changed

Currently, many of the obligated parties are large entities with sufficient resources, staff, expertise and tools to comply with registration, reporting and recordkeeping requirements under the RFS program. The EPA is concerned that moving the point of obligation as proposed by the petitioners could bring in many small entities that may not have the resources or expertise to comply. The addition of a number of small entities with relatively less regulatory experience and expertise could lead to increased overall noncompliance with RFS requirements. This could be seen as increasing the overall regulatory burden due to an influx of more parties (many of which may be small businesses) that have little or no familiarity with the RFS program, and it would

[219] See EPA Annual Compliance Data for Obligated Parties and Renewable Fuel Exporters under the Renewable Fuel Standard (RFS) Program; Table 1. https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and#total-gasoline

[220] See, e.g., Comments from CVR Energy, EPA-HQ-OAR-2016-0544-0396; Comments from the Small Refiners Coalition, EPA-HQ-OAR-2016-0544-0406.

likely also increase the administrative burden on the EPA to help educate these entities to help them comply, and to ensure their compliance.

Further, in any rulemaking to modify the RFS point of obligation, the EPA would need to consider impacts to small entities, as it did in its prior rulemakings. Congress itself considered the relief appropriate for small refineries that are obligated parties, exempting them through 2010 and then allowing for an extension of their exemption if warranted by a DOE study or through the EPA's review of small refinery petitions alleging that their compliance would result in disproportionate economic hardship. The EPA used its discretion in the 2010 RFS2 rule to extend similar relief to the few additional small refiners that did not qualify as small refineries. The EPA convened a Panel under the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA) to consider whether additional relief to small refiners or refineries was warranted. Were we to propose changing the point of obligation, we would need to ensure that small businesses were aware of this proposed change and potential impact to their business by re-engaging in the SBREFA process. Since the statute contains no specific provisions providing relief for small entities that are "position holders" or blenders, the EPA's analysis in considering the need for, and fashioning appropriate relief would potentially be more complex. The SBREFA process includes a number of steps and would take some time to implement properly. For example, before beginning the formal SBREFA process, the EPA would need to engage in outreach with entities that would potentially be affected by the proposed change and provide the small businesses with an early opportunity to ask questions and discuss their concerns with the upcoming rulemaking. Furthermore, we reasonably expect that there would be strong interest from some stakeholders to exempt small businesses from RFS obligations. If exempted, these parties could have a (potentially significant) financial advantage over parties that do have RFS obligations and this dynamic could result in an increasing number of small businesses entering this market. Regardless of the outcome of the SBREFA process, it is clear that the RFS market would experience significant uncertainty in such a transition and that the uncertainty may last for some time.

We expect there would be more non-compliance if we changed the point of obligation because blenders and "position holders" are likely to have less experience and fewer resources to be able to comply with the registration, reporting and recordkeeping requirements under the RFS program. Further, we believe the number of obligated parties would significantly increase, which would place greater strain on limited resources to ensure compliance and conduct program oversight. In particular, the information received from the IRS after the proposed denial was issued has strengthened our rationale for why and how administrative costs and the potential for fraud and/or non-compliance would increase with a change in point of obligation to "position holder." Since there is an approximately 30 percent turnover from year to year in the 720 tax filers program, it would require significant resources to identify those new obligated parties and to verify that no other obligated parties are evading the requirements. It would also require an increase in resources to provide compliance assistance to those new obligated parties as they learn a new program for the first time, or become re-acquainted with it after a period of non-activity. Additionally, while current obligated parties typically have significant assets that could

potentially be used to pay civil penalties and to purchase RINs to replace any determined to be fraudulent, it is reasonable to assume that many "position holders" and blenders have relatively fewer tangible assets or real property. It is possible that companies with few tangible assets could violate the RFS standards, make a quick profit, and shut down or leave the country without being brought to justice for their actions. Even if we were able to locate these parties and prevail in the civil or criminal proceedings, these parties could file for bankruptcy and never have to purchase replacement RINs or pay penalties associated with noncompliance. This could lead to less renewable fuel use than intended, and could unfairly disadvantage other obligated parties that meet their RFS obligations. The decreased potential for EPA to ensure through enforcement actions that the RIN system is made whole for any noncompliance would negatively impact the integrity of the RFS program and introduce still more uncertainty into the RIN market.

In the proposed denial, the EPA argued that placing the obligation on a smaller number of parties with significant assets generally results in a more efficient and therefore more effective program. The EPA stated that refiners and importers generally have greater resources than downstream market participants that enable them to provide oversight of the RIN generators to help ensure that the RINs being traded in the marketplace are valid. Changing the point of obligation, we posited, would require that newly obligated parties make the necessary investments to enable compliance with their new RFS obligations. This could take a significant amount of time and represent a significant financial burden to the new obligated parties, especially as we expected that many would be smaller companies with fewer resources than the existing obligated parties.

The EPA received some comments that "position holders" are big and sophisticated companies that would not be financially burdened by RFS compliance and RIN validity oversight duties. In its engagement with IRS during and after the comment period, the EPA requested from IRS data on the quantity of gasoline and diesel reported by "position holders" in calendar year 2016 in order to assess the size of the companies. The IRS was unable to provide the names associated with each volume of fuel, or the names of the parties that paid excise tax for gasoline or diesel more generally. Instead, the IRS provided EPA with a dataset that grouped the 443 "S" registrants that paid excise tax for gasoline or diesel in calendar year 2016 into blocks of five in descending order of gallons reported; for each block of five registrants, the dataset aggregated the gasoline and diesel gallons reported into one number.[221] Grouping the parties that paid excise tax in 2016 in this way resulted in a dataset of 86 data points for the EPA to analyze. The EPA compared this information to similar data available to the Agency from the obligated parties' 2016 RFS compliance reports. From this information, the EPA compared the volume of gasoline and diesel produced or imported by the 100 largest parties to the total reported volume gasoline and diesel volume in both the IRS and EPA data sets. The 100 largest obligated parties (per the current RFS definition) reported gasoline and diesel volumes that were 95% of the total volumes reported by all obligated parties. Similarly, the 100 "position holders" with the largest volumes

[221] For example, IRS reported the quantity of gasoline and diesel reported by the five largest "position holders" in 2016, the volume produced by the 6th-10th largest "position holders," the volume produced by the 11th-15 largest "position holders," etc. As noted above, the IRS did not provide the identity of the parties that paid excise tax for gasoline or diesel in 2016. See *IRS Aggregated Volume Data*.

accounted for over 95 percent of all volumes reported by all "position holders" paying excise taxes on gasoline and diesel in 2016. This suggests that the differences between the number of obligated parties under the current RFS regulations and "position holders" is not merely the result of company aggregation, as the proportion of total fuel represented by the 100 largest parties in each data set are similar.

The IRS data also showed that over 99.5% of all gasoline and diesel is sold by the 215 largest "position holders." This means that the remaining 228 registrants[222] – a majority of "position holders" in fiscal year 2016 – together accounted for less than 0.5 percent of all volumes reported on the IRS Form 720. If EPA changed the point of obligation to the "position holders" of gasoline and diesel as requested by the petitioners, we would expect a large number of new obligated parties. For 2016 alone there would have been an additional 323 obligated parties.[223] However, since there is approximately 30 percent turnover from year to hear in the identity of the "position holders" the total number of parties who would have the role of "obligated party" over the years could be significantly higher and the lack of stability in the pool of obligated parties would mean more difficulty in tracking and accounting for those parties. The EPA expects that a great many of the parties who would not consistently be obligated parties would be obligated for small volumes of gasoline and diesel, since the total volume of obligated fuel from the 228 "position holders" with the lowest volume of reported gasoline or diesel combined is projected to be less than 0.5% of the total obligated volume of gasoline and diesel sold in the United States. This data strongly supports EPA's assessment that changing the point of obligation to the "position holders" would result in an obligation being placed on a large number of previously unobligated parties, and that many of these newly obligated parties are likely to be small businesses.[224]

C. The EPA Would Need to Establish Transition Provisions

The current RFS regulations allow parties to satisfy up to 20% of any given RVO with RINs generated in the previous year, effectively allowing parties to "carry over" a limited number of RINs for use (by them or others to whom they may sell these RINs) in satisfying RFS compliance obligations the following year. Similarly, obligated parties that have an insufficient number of RINs to demonstrate compliance at the compliance deadline may carry forward the deficit into the following year without penalty, provided they satisfy both their deficit and full RVO the following year. Compliance data submitted to the EPA indicates that, in aggregate, parties carried over approximately 2.5 billion 2016 RINs into 2017. While smaller in magnitude,

[222] This number is calculated by subtracting the 215 "position holders" responsible for 99.5% of all gasoline and diesel from the total number of 443 "position holders."
[223] This number is calculated by subtracting the number of obligated parties under the current RFS regulations in 2016 (120) from the number of "position holders" that sold gasoline or diesel in 2016 (443)
[224] As discussed further in Section V.B., some parties who would become obligated under a change to the definition of "obligated party" may choose to adjust their business practices to avoid an obligation under the RFS program. If parties were to take this action, this could mitigate some of the concerns raised in this section, but would be unlikely to cause all parties to change their practices and would likely have other ramifications.

a number of parties also carried forward an aggregate deficit of approximately 400 million RINs from 2016 into 2017.

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If the EPA abruptly changed the point of obligation to the fuel blenders or "position holders" we would also impact the RVOs for obligated parties in future years relative to what they would have reasonably anticipated under the existing point of obligation, thus raising concerns about fairness. In some cases, these changes could be significant. Refiners and importers with significantly lower RVOs under the new point of obligation may find themselves in possession of significantly more RINs, including carryover RINs, than they desire or can use. Conversely, parties with a significantly higher RVO under the new point of obligation may find themselves with lower balances than they would desire to protect themselves against shortfalls in RIN availability or RIN price volatility. Unlike the current situation, where the number of carryover RINs held by an obligated party is primarily the result of the decisions made by that party under a consistent regulatory structure, the change in the size of each obligated party's RIN holdings relative to its obligations under the RFS program would be the result in a change in the definition of the obligated parties many years after the point of obligation was established through a notice and comment rulemaking.

While the tradable nature of the RINs in the RFS program would help to mitigate these potential negative impacts, a change to the point of obligation could also cause volatility in the market. Parties with excess RINs could recover some or all of the costs associated with acquiring these RINs, or potentially make a profit, by selling them to newly obligated parties or those who desire to acquire a bank of carryover RINs to protect themselves from future RIN shortfalls or market volatility. The ability for parties that possess excess carryover RINs to recover the cost of the RINs they hold by selling them to other parties, however, will be largely impacted by the effect changing the point of obligation has on the price of RINs. If, as some of the petitioners have suggested, as a feasible or desirable outcome of changing the point of obligation the price of RINs were to fall dramatically, then this change could have a significant negative financial impact on parties that find themselves in the possession of excess RINs due to a change in the point of obligation. Even if EPA were to take steps such as providing significant lead time to minimize impacts, a change to the point of obligation could result in RIN market volatility and disparities in RIN-holdings.

D. Changing the Point of Obligation Would Require Significant Changes to EMTS and Other Electronic Systems

A change in the point of obligation would necessitate changes to the Agency's registration and reporting systems. This would result in adding complexity and stress to already complex systems. It could potentially lead to degradation in service and reduced availability to all system users. For any given compliance year since 2010, between 1,300 – 1,500 parties participate in the RFS program as renewable fuel producers, RIN owners or obligated parties. Currently, EMTS averages about 23,000 transactions daily.

As discussed previously, shifting the point of obligation downstream could result in about 450 obligated parties in EMTS in any given year. This could result in an increase in EMTS transactions (transfers, separations and retirements) as a larger number of RIN batches (many of them likely of smaller volume) change hands between a greater number of obligated parties, without any increase to the total number of RINs in the system. The OTAQReg registration system would need to be modified to reflect the new definition of obligated party, and both existing non-obligated EMTS participants and new participants would need to register/re-register. Rights and access controls to EMTS would need to be revised to ensure proper reporting and oversight of RIN transactions.

In addition to changes to reflect the additional numbers and roles of registrants in EMTS, changing the point of obligation may require additional functionality for EMTS to take account of changes in business practices and additional potential for non-compliance, including avoiding compliance obligations, failure to identify as an obligated party, or not understanding RFS requirements. The EPA may find that the additional potential for non-compliance requires additional reporting of information not currently tracked in EMTS, such as accounting for movements of physical volumes of gasoline and diesel fuel between potential obligated parties, similar to a designate-and-track system, to ensure that RFS obligations are assigned to the proper parties. Such a system would include additional reporting by parties such as refiners, marketers, and blenders to ensure RFS goals are being met. Ancillary reports such as quarterly and annual compliance reports submitted to CDX and annual attest engagements would also increase in volume and complexity.

V. Changing the Point of Obligation Could Cause Significant Market Disruption

In the petitions the EPA has received requesting a change to the point of obligation in the RFS program, the petitioners generally characterize their proposed changes to the point of obligation as minor or simple. The EPA disagrees with these characterizations and believes that changing the point of obligation would be a significant change for the RFS program, and would likely lead to significant changes in the fuels marketplace more generally.

A. Market Participants Have Made Significant Decisions on the Basis of the Existing Regulations

When EPA first instituted the RFS program in 2007, and again when EPA significantly revised the RFS regulations in 2010 in response to the EISA amendments, the EPA requested and received many comments related to the point of obligation of the RFS program. These comments were carefully considered and the EPA specifically sought the input of the refining industry. The decision to place the point of obligation on refiners and importers in 2007, and to uphold that decision in 2010, was made with the support of much of the refining industry.

Since then all parties regulated in the RFS program have made significant investments and decisions about their participation in the program and their position in the market on the basis of the existing regulations, including the definition of obligated parties. Some parties sought to

increase their access to RINs acquired by blending renewable fuels by expanding their presence at terminals where renewable fuels are blended, or investing in blending infrastructure downstream of terminals. Other parties entered into contracts to purchase renewable fuel with attached RINs and/or separated RINS to satisfy their own needs or for re-sale to obligated parties, while yet others became major renewable fuel suppliers as well. Each year obligated parties decided how to best satisfy current and future RIN obligations, including whether or not to carry over RIN deficits or excess RINs into future years.

Each of these decisions was made with the expectation that each party's RFS obligation in future years would continue to be proportional to the volume of gasoline and diesel fuel they refine or import, as is the case under the current RFS regulations. If the EPA were to change the point of obligation as requested by the petitioners, RFS obligations would instead be proportional to the volume of gasoline or diesel fuel that parties blend with renewable fuel, or the volume of gasoline and diesel fuel sold by parties immediately above the rack. This would substantially impact the relative size of many parties' RFS obligations and would very likely result in efforts to reposition themselves in the marketplace, either by renegotiating contracts or even seeking to buy or sell assets associated with the blending of renewable fuels. If changing the point of obligation of the RFS program were reasonably likely to result in a significant increase in the amount of renewable fuel that was produced, distributed, and used in the United States relative to the current point of obligation such a change may be justified; however, since we do not believe that changing the point of obligation will result in significant increase in the production distribution and use of renewable fuel, these impacts are important to consider.

B. If the Point of Obligation is Changed, Parties Would Be Expected to Reposition Themselves to Avoid or Minimize RFS Obligations

One of the desired outcomes of changing the point of obligation in the RFS program expressed by the petitioners is to shift the obligation to renewable fuel blenders or "position holders" that have access to RINs through the blending of renewable fuels. While assessing these petitions, the EPA received letters from a number of independent fuel marketers and parties that own a large number of retail fueling stations.[225] These parties are generally not currently obligated parties (because they do not typically refine gasoline or diesel fuel, however on occasion some import gasoline and/or diesel fuel), but would likely become obligated parties if the EPA changed the point of obligation as requested by the petitioners as they blend renewable fuels and/or are "position holders" at terminals. In addition to questioning many of the benefits of changing the point of obligation claimed by the petitioners, these parties stated that if the EPA changed the point of obligation they would likely adjust their business practices in an effort to avoid becoming obligated parties, either by purchasing fuels already blended with transportation fuel and/or purchasing fuel below the rack.[226]

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[225] See Letter from Tim Columbus to Administrator McCarthy, August 15, 2016; Letter from RaceTrac to Administrator McCarthy, August 17, 2016; Letter from QuikTrip to Administrator McCarthy, August 17, 2016; Letter from Pilot Flying J to Administrator McCarthy, August 16, 2016.
[226] Ibid.

In their letters to the EPA, these parties acknowledged that by moving below the rack they may give up a number of advantages that contribute to their profitability, such as the ability to purchase fuel in bulk at a slight discount, the ability to better control their fuel supply, and advantages related to the collection of taxes. Nevertheless, these parties stated that the expected costs associated with becoming obligated parties, primarily the costs associated with developing expertise necessary to manage their new RFS obligations and the documentation requirements, may very well outweigh any benefits currently experienced in their position as renewable fuel blenders and/or "position holders." In their arguments these parties referenced their experience with California's LCFS program, which allows compliance obligations to be passed on to the "position holders." They stated that this has resulted in less competitive markets at the rack, increasing fuel prices for consumers, as many parties sought to purchase fuel below the rack, rather than above the rack, to avoid LCFS obligations. They claimed that this would be especially true for the many small entities currently engaged in the gasoline and diesel fuel spot markets. The EPA primarily spoke with and received written communication from larger businesses that are currently blenders of renewable fuels and/or "position holders," however any overhead costs associated with being an obligated party would likely be proportionally more significant for small businesses.

If parties that would become obligated parties for the first time if the EPA were to change the point of obligation as requested by the petitioners react as they have claimed in discussions and written communication with the EPA, by adjusting their business practices to avoid becoming obligated parties under the new definition, this would significantly impact the expected results of such a change. Some of the concerns raised by the EPA, such as the large number of new parties that would become obligated parties under the new definition and the relatively small nature of these parties, would be mitigated, as these parties likely would adjust their businesses to avoid becoming obligated parties under the new definition. However, such market restructuring would likely have other market ramifications.

While it is uncertain which parties would ultimately have increased obligations if EPA were to change the point of obligation as requested by the petitioners and independent fuel marketers and retail station owners exit their current market positions as renewable fuel blenders and "position holders," it is possible that the current obligated parties that do not sell gasoline and diesel at the rack, would take up these positions in an effort to find consumers for the fuel they produce and import. If this were to happen, the end result of this significant market restructuring would be that the RFS obligations would not substantially change from what they are under the current definition of obligated parties. Refiners and importers would likely take on terminal positions and the role of blending renewable fuels abandoned by the parties who currently satisfy these roles in the market. Ultimately, the RFS obligations may not be substantially different in this scenario than they are today, and if this were the case it is questionable if the benefits claimed by the petitioners would not be realized. During the time period when the EPA went through the rulemaking process to change the point of obligation, however, and as the fuels marketplace adjusted to the realities of the change in the point of obligation there would be significant market uncertainty and potential turmoil. To the degree that the EPA invests significant agency resources to enable the change in the point of obligation and fuels industry participants withhold significant investment decisions until the EPA's final decision and the fallout from the decision

are known, this could have a significant negative impact on achieving the goals of the RFS program.

In comments, those in support of changing the point of obligation suggested that the benefits of being a "position holder" would outweigh any costs of becoming an obligated party under the RFS system, and "position holders" would not change their market practices in order to avoid the RFS obligation, citing to benefits such as "the ability to purchase fuel in bulk at discount, the ability to better control their fuel supply, and advantages related to the collection of taxes."[227] In contrast, many parties who would become obligated under the Petitioners' proposed definition stated that they would indeed change their market position or at least reevaluate their position purchasing fuel above the rack.[228] Some stated that they currently purchase some of their fuel above the rack, and some fuel below the rack depending on the costs and market dynamics, indicating that parties would be willing to modify their position in the future as well. Based on the evidence before it, EPA believes some parties would change their market position in response to a change in the point of obligation, and that such a change further supports EPA's denial.

While changing the point of obligation in the RFS program would be unlikely to better achieve the goals of the RFS program, especially if many of the fuel blenders, independent marketers, and retail station owners change their business practices to avoid becoming obligated parties, these changes could have broader negative impacts in the fuels marketplace. If the independent marketers and retail station owners cease to be "position holders," we believe the market positions they vacate are likely to be taken up by existing refiners. This could start to reverse the fuel industry's transition over the last decade to move away from the integrated model in which refiners disinvested from downstream infrastructure at wholesale and retail. The integrated model has previously caused concerns regarding fuel price impacts and manipulation in the market. We believe that changing the point of obligation could provide an incentive for a shift in control to a relatively few large parties upstream and remove choices and flexibilities that downstream businesses have negotiated over the years in order to hold a position in what is currently a highly competitive fuels market. Changing the point of obligation as requested by the petitioners could result in greater market concentration in certain markets. For example, if independent marketers and retailers give up their positions at terminals in an effort to avoid becoming obligated parties it is possible that some terminals could become dominated by a small number of refiners, or even a single refiner. This reduction in competition could result in higher fuel prices for the retail stations that purchase fuel from these terminals, and ultimately for their consumers. This concern was echoed by many commenters.[229] The absence of independent marketer and retail station owners at terminals may also negatively impact the ability for retail station owners to purchase fuel on the spot market, instead forcing them to rely on longer term contracts with refiners to a greater degree. This would further limit the retailers' options to purchase the lowest cost fuel. These are just examples of the negative impacts that could result from broader market restructuring if the EPA were to change the point of obligation of the RFS program as requested by the petitioners.

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[227] See, e.g., Comments from CVR Energy, EPA-HQ-OAR-2016-0544-0396.
[228] See, e.g., Comments from UPS, EPA-HQ-OAR-2016-0544-0076.
[229] See, e.g., Comment from Casey's, EPA-HQ-OAR-2016-0544-0268; Comments from American Trucking Association, EPA-HQ-OAR-2016-0544-0355.

VI. Other Comments

The EPA received comments contending that the RIN market is "illegal," as the statute provides that transfer of credits must be "for the purpose of complying" with the RFS program, CAA section 211(o)(5)(B), and that unobligated blenders and RIN traders do not comply with the RFS program.[230] They also state that the "EPA allows entities to generate RINs from blending any volume of renewable fuel,"[231] and not just those quantities greater than the statutory volumes, as suggested by the statute.[232] In response, EPA notes that the RIN system was initially established through notice and comment rulemaking with considerable support from stakeholders in RFS1, and then reaffirmed with relatively minor adjustments in RFS2. Thus, the time to seek judicial review of the creation of the RIN compliance system is past. EPA did not reopen this matter in the context of its proposed denial of the petitions seeking a change in the point of obligation, so these comments are beyond the scope of this action. By means of explanation, and without intending by this response to open this resolved matter for further debate or consideration, we note that the RIN system serves two purposes: as a general compliance mechanism, and as a means of implementing the statutes' credit provisions. These commenters ignore or minimize the compliance mechanism aspect of the RIN system, and EPA's authority under CAA Sections 211(o)(2) and 301 to establish a compliance program which could include credit elements that extend beyond the specific elements required in CAA Section 211(o)(5).

Monroe Energy stated that the EPA had an obligation to conduct a jobs analysis under CAA section 321(a) before it denied the petitions for rulemaking, citing *Murray Energy Corp. v. McCarthy*, No. 5:14-CV-39 (N.D. W. Va. 2014). The company further stated that, had the EPA performed this jobs analysis, EPA would have recognized the threat of closures and job losses to merchant refineries. First, the EPA notes that on appeal of the district court decision cited by Monroe Energy, the Fourth Circuit Court of Appeals held that CAA section 321(a) does not impose a non-discretionary duty on the EPA. *Murray Energy Corp. v. EPA,* 861 F.3d 529 (4th Cir. 2017). Second, CAA section 321 does not, as this commenter suggests, specify that completion of a jobs analysis is a prerequisite to the Agency's authority to act on a petition for rulemaking or to take any other final agency action. Finally, the EPA has evaluated claims that the RFS program as currently structured harms merchant refiners, and disagrees with the commenter that this is the case *See* Section II.C, *supra*.

The EPA received additional comments that are outside the scope of this determination. Some commenters suggested that conventional biofuels lack environmental and greenhouse gas benefits. Other commenters suggested that the RFS should incent co-processing of renewable feedstocks with petroleum at refineries.[233] The EPA also received comments suggesting a "diesel

[230] See, e.g., Comments from CVR Energy, EPA-HQ-OAR-2016-0544-0396; Comments from the Small Refiners Coalition, EPA-HQ-OAR-2016-0544-0406.
[231] Commenters' suggestion that RINs may be generated from blending is inaccurate; RINs are generated at the point of renewable fuel production, and can be separated at the point of blending. See 40 CFR 80.1426-27.
[232] CAA section 211(o)(5)(A)(i)
[233] See Comments from UPS, EPA-HQ-OAR-2016-0544-0076.

disparity:" that refiners that produce a higher percentage of diesel have difficulty meeting their RVO through blending.[234] In addition, some commenters suggested that the RFS program should not include imported biofuel.[235] As these comments are outside the scope of this determination, we decline to address them here.

VII. Conclusion

Congress authorized the EPA to require "refiners, importers, and blenders, as appropriate" to be obligated parties in the RFS program.[236] After reviewing the petitions the EPA has received requesting changes to the point of obligation in the RFS program, reviewing the comments submitted on our proposed denial of these petitions, assessing the relevant data available to the EPA, and speaking with and reviewing written communication from numerous parties that would likely be impacted by the requested change, the EPA continues to believe that the point of obligation is appropriately placed on refiners and importers, consistent with the current regulation. We believe that the parties requesting this change significantly underestimate the scope and impacts of the changes that would result from the number and nature of additional parties that would become obligated parties if the point of obligation were changed. In addition, we do not believe that the evidence indicates that the changes Petitioners have requested would result in additional production, distribution, and use of renewable fuels as transportation fuel in the United States. If anything we believe it could negatively impact renewable fuel volumes, especially during the substantial transition that would be required. Both in the short and long-term, we believe that the program is more likely to succeed with the current set of obligated parties. The EPA has evaluated the functionality of the RIN market and believes that the RIN program provides a generally efficient and equitable means for all obligated parties to meet their compliance obligations, and that the shortfalls in renewable fuels to date are attributable to broader market forces that would be unaffected by merely changing the point of obligation. It is likely that if the changes requested by the petitioners were made, many of the parties that would become obligated parties as a result of the change in the definition of obligated parties would reposition themselves in an effort to avoid or minimize their obligations under the RFS program. Such market repositioning could minimize any long term impacts of the proposed change on the production, distribution, and use of renewable fuel, but may also have far-reaching negative consequences across the fuels marketplace, and increase fuel prices for consumers. In addition, the EPA believes the point of obligation should be retained to promote stability and regulatory certainty.[237] The Administrator is therefore denying the petitions requesting that the EPA initiate a rulemaking process to reconsider or change the regulation identifying refiners and importers of gasoline and diesel fuel as the entities responsible for complying with the annual percentage standards adopted under the RFS program.

EPA has determined that this action is nationally applicable for purposes of CAA section 307(b)(1). since the result of this action is that the current nationally-applicable regulation defining

[234] See Comments from CVR Energy, EPA-HQ-OAR-2016-0544-0396; Comments from Small Refiners' Coalition EPA-HQ-OAR-2016-0544-0406.
[235] See Comments from the Small Refiners' Coalition, EPA-HQ-OAR-2016-0544-0406.
[236] CAA Section 211(o)(3)(B)(ii)(I).
[237] In addition, as noted in section III.A. EPA does not interpret the Clean Air Act as authorizing us to place the point of obligation on distributors or on "position holders" that are not refiners, blenders or importers.

obligated parties who must comply with nationally applicable percentage standards developed under the RFS program remains in place. In the alternative, even if this action were considered to be only locally or regionally applicable, the action is of nationwide scope and effect for the same reason, and because the action impacts entities that are broadly distributed nationwide who must comply with the nationally-applicable RFS percentage standards, as well as other entities who are broadly distributed nationwide that could potentially have been subject to such requirements if EPA had elected to grant the petitions seeking a change in the definition of obligated parties.

Proposed RFS Small Refinery Exemption Decision

EPA United States Environmental Protection Agency

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EXECUTIVE SUMMARY

With this notice, EPA is seeking comment on a proposal to establish a change in our statutory interpretation of the Clean Air Act (CAA or "the Act") small refinery provisions and, applying this interpretation, to deny 65 pending petitions from small refineries seeking extensions of their small refinery exemptions (SREs) from the Renewable Fuel Standard (RFS) program. The petitions concern one or more compliance years between 2016 and 2021. This proposed adjudication and EPA's accompanying change in its interpretation of the relevant CAA provision are compelled by the 2020 ruling in *Renewable Fuels Association, et al. v. EPA*, 948 F.3d 1206 (10th Cir. 2020) (*RFA*), the Supreme Court's subsequent decision in *HollyFrontier Cheyenne Refining, LLC, et al. v. Renewable Fuels Ass'n, et al.*, 114 S.Ct. 2172 (2021), EPA's experience implementing the RFS program for more than a decade, and our exhaustive analysis of how the RFS credit market functions. EPA here proposes to establish that the small refineries with pending petitions before the Agency have failed to demonstrate the disproportionate economic hardship (DEH) that the CAA requires for EPA to grant such exemptions, and therefore the 65 pending SRE petitions should be denied.

The conclusions we rely on in presenting this proposal are: (1) Regardless of the mechanism by which small refineries and other obligated parties comply with their RFS obligations, the RFS compliance costs are the same for all obligated parties and thus no party bears RFS compliance costs that are disproportionate relative to others' costs; (2) Obligated parties, including small refineries, recover their compliance costs through the market price they receive when they sell their fuel products and thus do not bear a hardship created by compliance with the RFS program; and (3) With no disproportionality and no economic hardship, there can be no disproportionate economic hardship pursuant to the statute.

In addition to seeking comment on these conclusions, EPA requests comment on general as well as specific aspects of this proposed adjudication, including but not limited to the following[1]:

- The proposed conclusion that DEH must be caused by compliance with the RFS program to warrant an exemption.
- The proposed finding that the structure of the RFS program places a proportional burden on all obligated parties based on their gasoline and diesel fuel production volume.
- The proposed finding that the structure of the RFS compliance system EPA put in place, which enables the use of renewable fuel credits known as Renewable Identification Numbers (RINs), provides equal access to all obligated parties to the same means of compliance.
- The proposed finding that the fuel and RIN markets are competitive and that RIN costs per gallon are the same to all obligated parties regardless of their role in the market, their size, or whether they acquire RINs through blending renewable fuel or by purchasing RINs (credits) representing that volume of fuel.
- The proposed finding that RIN costs are passed through to consumers.

[1] EPA has published a *Federal Register* notice that announces this proposed action and established a public docket to receive these comments (Docket ID No. EPA-HQ-OAR-2021-0566).

- The proposed conclusion that, since passed through to consumers, the compliance costs of the RFS program do not impose economic harm to obligated parties and, therefore, the RFS program does not cause DEH for small refineries or any obligated party.
- Additional data that may illustrate the relationship between RFS compliance costs and the price of transportation fuel and blendstocks.
- The proposed change in approach to SRE eligibility described in Section IV.
- The proposed decision to deny all pending SRE petitions for the reasons described herein.

CAA section 211(*o*)(9)(A)(i) exempted small refineries from the RFS program through compliance year 2010. CAA section 211(*o*)(9)(B)(i) authorizes the Administrator to temporarily extend those exemptions "for the reason of disproportionate economic hardship." Under CAA section 211(*o*)(9)(B)(ii), in evaluating SRE petitions, EPA shall "consider the findings" of a study conducted by the Secretary of Energy pursuant to CAA section 211(*o*)(9)(A)(2) and "other economic factors" to decide "whether compliance with the [RFS] requirements . . . would impose a disproportionate economic hardship on small refineries." The statute does not define DEH and identifies no particular "economic factors" to be considered, and case law establishes that EPA has substantial discretion in how it implements the SRE provision. Relying on this discretion, EPA's approach to SREs has evolved since 2011, shaped at various times by prevailing administration policies, litigation, and the increasing knowledge and real-world market data acquired through implementation of the RFS program.

The impetus for the statutory interpretation we are proposing for comment (while also seeking comment on the proposed SRE adjudications) is the *RFA* opinion issued by the U.S. Court of Appeals for the Tenth Circuit. The court acknowledged EPA's shifting approaches to SREs since 2011 and ruled that, for the SRE grants at issue before that court, EPA had exceeded its statutory authority by extending temporary exemptions to those small refineries. In remanding those actions, the court held that: (1) In granting exemptions based on economic factors unrelated to compliance with the RFS program, EPA had exceeded its statutory authority to exempt small refineries from their RFS obligations "for purpose of [DEH]" because the statute authorizes EPA to extend exemptions only where RFS compliance costs are the *cause* of the small refinery's hardship; and (2) EPA had acted arbitrarily and capriciously in granting exemptions without explaining whether and how the subject SRE grants were consistent with EPA's firmly established position that all parties subject to RFS obligations recover their compliance costs through a feature of the market EPA identified as "RIN cost passthrough."

Following the Tenth Circuit Court ruling, small refinery petitioners began submitting to EPA supplemental materials to support their requests for exemptions. Many petitioners argue that they bear comparatively high RFS compliance costs because they must buy more expensive RINs (the renewable fuel credits that are the currency of the RFS compliance market), compared to large integrated refiners that can acquire cheaper RINs by blending renewable fuel. Petitioners also argue that they are unable to increase the price they charge for the petroleum fuel[2] they

[2] Generally, when we refer to "fuel" or "petroleum fuel" in this proposal, we are including in that term petroleum blendstocks. A "blendstock" is defined as "any liquid compound or mixture of compounds (not including fuel or fuel additive) that is used or intended for use as a component of a fuel." 40 CFR 1090.80.

produce to recover their higher compliance costs because they are "price takers" and do not control market prices. As we present in this proposal, EPA has carefully evaluated these claims; we find them not to be valid, and, in some cases, the supplemental submissions even provide support to our prior analyses, which the Tenth Circuit cited in *RFA* and which we propose to extend here.

Defeating the small refineries' claims at the threshold and at the same time fundamental to EPA's analyses are two economic phenomena in the RFS fuels market. Contrary to the first claim of the small refineries, we find that all RFS obligated parties, including small refineries, bear the same cost to acquire RINs whether the RINs are purchased in the market or acquired by blending renewable fuel. This occurs because parties that acquire RINs by blending renewable fuel must discount the price of the renewable fuel feedstocks (e.g., the ethanol in E10[3]) by the current market value of the RIN when they sell renewable fuel. Thus, a refinery that blends renewable fuel pays the market price for the RINs it acquires from blending by offering the discount it must give purchasers when it sells the renewable fuel. We refer to this first market phenomenon, where the market price of renewable fuel is discounted by the RIN price, as the "RIN discount."

The second phenomenon is refineries' recovery of the costs they bear in acquiring RINs in the prices they charge for the petroleum fuel they sell. Throughout this document we will refer to this economic outcome as "RIN cost passthrough" because refineries' RFS compliance costs are passed through in higher prices for the petroleum fuel (i.e., gasoline and diesel fuel) they produce. While it is true that small refineries have no control over the market price for the petroleum fuel they sell, the price that they receive in the market does reflect the full RFS compliance cost that is the same for all parties per gallon of fuel, allowing these costs to be passed through. Hence even as price takers, small refineries recover their RFS compliance costs when they receive the market price for the fuel they sell. Together, the two distinct market phenomena of the "RIN discount" and "RIN cost passthrough" reflect the cross-subsidy nature inherent to the RFS program. The "RIN discount" lowers the market price of renewable fuel to facilitate their sale while "RIN cost passthrough" raises the market price of petroleum fuel to recover those costs.

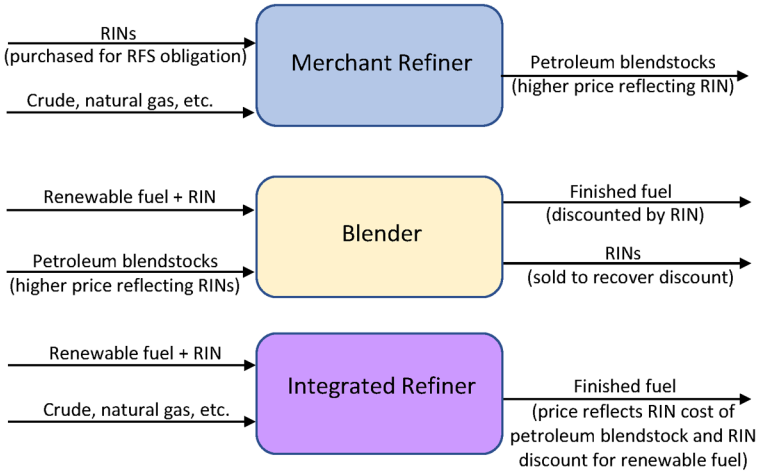
These economic outcomes are distinct, but are often conflated, especially in connection with blended fuels like E10 that include both elements (a discount in the price of the ethanol that is blended to make the fuel while the cost of the petroleum portion of the fuel increases). To help illustrate how these two distinct aspects of the fuels market operate for different market participants, the figure below shows the inputs and outputs of the fuels market for merchant refiners, blenders, and integrated refiners. In the following sections, we highlight which of these two phenomena—the "RIN discount" or "RIN cost passthrough"—we are referring to as we detail our evaluation of the information submitted by the small refinery petitioners.[4]

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[3] E10 is a finished fuel blend composed of 90% gasoline blendstock and 10% ethanol. The gasoline blendstock is often referred to as BOB (blendstock for oxygenate blending).

[4] A comprehensive discussion of the RIN market impacts on different obligated parties can be found in Section IV.D.2.c.

Figure ES-1: Simplified Illustration of Fuels Market Participants



Before issuing this proposal, however, EPA exempted small refineries from their RFS obligations solely based on metrics that did not account for RIN cost passthrough. Thus, EPA did not require any demonstration that the DEH experienced by the refinery was due to the RFS program. Neither did EPA reconcile this reasoning with EPA's own finding that the costs of RINs used for compliance with the RFS program are the same for all obligated parties and passed through by all obligated parties to consumers (RIN cost passthrough).

Now, as briefly described above and based on the detailed analyses herein, EPA has reached the following proposed conclusions: (1) Regardless of the mechanism by which small refineries and other obligated parties comply with their RFS obligations, the RFS compliance costs are the same for all obligated parties and thus no party bears RFS compliance costs that disproportionate relative to others' costs; (2) Obligated parties, including small refineries, recover their compliance costs through the market price they receive when they sell their fuel products and thus do not bear a hardship created by compliance with the RFS program; and (3) With no disproportionality and no economic hardship, there can be no DEH pursuant to the statute. Further, because EPA is here proposing to alter its statutory interpretation of its CAA authority to extend SREs only to small refineries whose claimed DEH is caused by the cost of complying with the RFS program, and not by other factors, EPA is here proposing to deny all of the pending SRE petitions currently before the Agency. This proposed action is supported by extensive market data and analyses, including information provided to EPA through recent active engagement with small refineries.

We are departing from past practice regarding SRE decisions by inviting comment on aproposed adjudication of the pending petitions, along with the analysis we provide to support our proposal. The goal of this public notice and comment process is to achieve the broadest possible dissemination of EPA's preliminary analysis, to gain public input on the analysis, and to solicit any further data or evidence interested parties may be able to provide to inform the final decision EPA must issue with respect to the pending SRE petitions. Commenters are encouraged to provide input on any aspect of this new statutory interpretation and our proposed adjudication of the pending SRE petitions, including but not limited to the RIN market analysis and conclusions detailed herein. We particularly request information or data to bolster or refute our analysis of the RIN discount and RIN cost passthrough principles and our proposed decision to deny the pending SRE petitions based on that analysis. This notice is not a final agency action. EPA is requesting comment on general as well as specific aspects of this proposal.

I. Proposed Adjudication and Request for Comment

EPA is proposing to require that small refineries: (1) Demonstrate that any DEH they experience is caused by compliance with the RFS program; and (2) Reconcile any such showing with RIN cost passthrough. This approach is described in more detail in Section III. The RIN cost passthrough phenomenon is explained in Section IV.D.2. EPA is also proposing to change its criteria for assessing a refinery's eligibility to receive an exemption from its RFS obligations. We are proposing to now require a small refinery to have received the original statutory exemption in order to be eligible to petition for an extension of that exemption, though a small refinery need not have had continuous exemptions since the original statutory exemption, consistent with the Supreme Court's holding in *HollyFrontier*[5] and as explained in Section IV.A.

EPA currently has 65 pending petitions from small refineries seeking SREs pursuant to CAA section 211(*o*)(9)(B) for one or more compliance years between 2016 and 2021.[6] EPA has completed its initial analysis of these petitions. After applying the new approach to DEH, and for the reasons described in this document, EPA is proposing to deny all of the pending SRE petitions as follows:

- Deny 1 SRE petition for the 2016 compliance year.
- Deny 1 SRE petition for the 2017 compliance year.
- Deny 3 SRE petitions for the 2018 compliance year.
- Deny 29 SRE petitions for the 2019 compliance year.
- Deny 28 SRE petitions for the 2020 compliance year.
- Deny 3 SRE petition for the 2021 compliance year.

In addition to proposing to deny all pending SRE petitions, EPA is proposing to make the following eligibility determinations for two refineries with pending petitions:[7]

- Determine that one refinery is ineligible to petition for an exemption for the 2019 and 2020 compliance years because it exceeded the crude oil throughput limit of 75,000 barrels per day in 2019, thereby making the refinery ineligible for an exemption in both 2019 and 2020 pursuant to applicable EPA regulations.[8]
- Determine that two refineries (including the one identified in the previous bullet) are ineligible to petition for an exemption for the 2019 and 2020 compliance years (and future compliance years) because they did not receive the original statutory exemption.

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[5] *See HollyFrontier Cheyenne Refining, LLC, et al. v. Renewable Fuels Ass'n, et al.*, 114 S.Ct. 2172, 2181 (2021) (*HollyFrontier*).

[6] Should we receive additional petitions for SREs subsequent to the release of this proposed action, we may decide to include those petitions in our final action, if appropriate.

[7] Though we are proposing to determine that these refineries are ineligible to petition for an exemption, we have also included them in the 65 pending petitions that would be denied by this proposed action because we are, in the alternative, also proposing to deny those petitions for the reasons described herein whether or not the small refineries are found to be eligible to petition for an exemption.

[8] 40 CFR 80.1401 & 80.1441(e)(2)(iii).

EPA requests comment on general as well as specific aspects of this proposed action in a notice published in the *Federal Register*, including but not limited to the following:

- The proposed conclusion that DEH must be caused by compliance with the RFS program to warrant an exemption.
- The proposed finding that the structure of the RFS program places a proportional burden on all obligated parties based on their gasoline and diesel fuel production volume.
- The proposed finding that the structure of the RIN system put in place by EPA provides equal access to all obligated parties to the same means of compliance.
- The proposed finding that the fuel and RIN markets are competitive and that RIN costs per gallon are the same to all obligated parties regardless of their role in the market, their size, or whether they acquire RINs through blending or by purchasing RINs.
- The proposed finding that RIN costs are passed through to consumers.
- The proposed conclusion that, since passed through to consumers, the compliance costs of the RFS program do not impose economic harm to obligated parties and, therefore, the RFS program does not cause DEH for small refineries or any obligated party.
- Additional data that may illustrate the relationship between RFS compliance costs and the price of transportation fuel and blendstocks.
- The proposed change in approach to SRE eligibility described in Section IV.
- The proposed decision to deny all pending SRE petitions for the reasons described herein.

In sum, EPA requests comment on all of these proposals and especially solicits any additional information that either supports or refutes the Agency's findings on RIN discount and/or on RIN cost passthrough. EPA in particular seeks information on the effects of these phenomena on diverse small refineries and on the extent to which small refineries suffer DEH as a result of compliance with their obligations. To be clear, this proposal seeks comment from the general public as well as comment and additional information and analysis from the individual petitioning refineries that supports or refutes these propositions as they apply to their respective petitions.

This notice is not a final agency action for purposes of CAA section 307(b)(1); it is not a rulemaking and is not subject to the various statutory and other provisions applicable to a rulemaking. Instead, this is a proposed adjudication of the 65 pending SRE petitions by: (1) Clearly articulating EPA's current interpretation of its statutory authority to grant SREs; (2) Presenting our analysis of all available data on RFS costs and market dynamics for public review and comment; and (3) Proposing to deny all of the pending petitions based on the current statutory interpretation and analysis described herein in a single action. EPA intends to take final action on the pending petitions based on the legal and factual analysis proposed herein, after considering the public comments submitted in response to this proposed adjudication.

This document is structured to provide a sequential explanation of EPA's new approach to SRE petition evaluation and of the data we analyzed to support this approach. It begins, in

Section II, by providing background on the RFS program, compliance with the RFS program, and the SRE provision of that program. Section II also provides a brief history of EPA's approach to evaluating SRE petitions and judicial review of EPA's SRE decisions. Section III presents the statutory requirements for EPA's evaluation of SRE petitions and EPA's new approach to SRE evaluation. Section IV provides EPA's analysis of the SRE eligibility and petition requirements and statutory construction of the CAA's SRE provision. It also presents a detailed explanation of RFS market economics including the costs of RFS compliance on obligated parties, and the implications of those costs on DEH. Section IV also includes a description of how EPA satisfied the statutory requirements for this proposed action,[9] then summarizes and responds to the arguments advanced by the petitioning small refineries to date as to how and why RFS compliance has caused their DEH. Section V provides EPA's proposed conclusions based on all the information presented herein.

II. Background and Program Interpretation

A. RFS Program

In 2005 and 2007, Congress amended the CAA to establish the RFS program.[10] Congress enacted this program to "move the United States toward greater energy independence and security" and to "increase the production of clean renewable fuels," among other purposes.[11] The statute specifies increasing annual "applicable volumes" for four categories of renewable fuel for the transportation sector: total renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel.[12] The specified applicable volumes for renewable fuel, advanced biofuel, and cellulosic biofuel are prescribed for each year through 2022, and for biomass-based diesel through 2012; EPA must determine the applicable volumes for subsequent years.[13]

Congress directed EPA to establish a compliance program and annual percentage standards to ensure that the applicable volumes are used each year.[14] To calculate these percentage standards, EPA divides the applicable volume for each type of renewable fuel established in the CAA or determined by EPA[15] by the Energy Information Administration's estimate of the national volume of transportation fuel that will be introduced into commerce in that year.[16] For example, if EPA set the percentage standard for total renewable fuel at 10 percent, an obligated party that produced 1,000,000 gallons of gasoline one year would need to ensure that 100,000 gallons of renewable fuel was introduced into the market that year.

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[9] CAA section 211(*o*)(9)(B)(ii) requires EPA to: (1) Consult with the Secretary of Energy; and (2) Consider the findings of the DOE study performed under CAA section 211(*o*)(9)(A)(ii)(I) and "other economic factors."
[10] *See* Energy Policy Act of 2005 (EPAct), Pub. L. No. 109-58, 119 Stat. 594; Energy Independence and Security Act of 2007 (EISA), Pub. L. No. 110-140, 121 Stat. 1492
[11] 121 Stat. 1492.
[12] CAA section 211(*o*)(2)(B)(i)(I)-(IV).
[13] *Id.*
[14] *Id.*; CAA section 211(*o*)(2)(A)(i), (iii) & (3)(B)(i).
[15] CAA section 211(*o*)(2)(B), (7)(A), & (7)(D)-(F).
[16] CAA section 211(*o*)(3)(A).

Congress authorized EPA to place the obligation to satisfy the applicable percentage standards on "refineries, blenders, and importers, as appropriate."[17] By regulation, EPA determined that refineries and importers of gasoline and diesel fuel must fulfill the requirements of the RFS program.[18] These "obligated parties" apply the percentage standards to their own annual production or importation of gasoline and diesel fuel to calculate their individual renewable volume obligation (RVO or "RFS obligation") for each type of renewable fuel. Thus, the RFS standards absent SREs place the same obligation on all producers and importers of gasoline and diesel fuel in proportion to their production volume.

B. Renewable Identification Number Credits

The CAA requires EPA to establish a credit trading program allowing obligated parties that acquire excess credits in one year to apply credits toward compliance in a subsequent year or to sell the credits to another obligated party for use in its own compliance.[19] In conjunction with EPA's authority under CAA section 211(*o*)(2)(B) to put in place implementing regulations for the RFS, and in compliance with CAA section 211(*o*)(5), we designed a much more flexible and comprehensive system of tradable credits (RINs). Section 211(*o*)(5) required only that EPA allow for the generation and trading of credits for obligated parties who refine, blend, or import excess renewable fuel. The RIN system fulfills that statutory provision, and also creates a fungible system of credit trading by not just obligated parties but also renewable fuel producers and others, creating an open, liquid market for RINs to allow obligated parties to comply with their RFS obligations. Under the RIN system, producers and importers of renewable fuel generate RINs for each gallon of renewable fuel they import or produce for use in the United States.[20] RINs are "assigned" to batches of renewable fuel by the producers and importers of renewable fuel.[21] RINs may be "separated" from those batches by a party that blends the renewable fuel into conventional fuel.[22] Once separated, RINs may be kept for compliance or sold.[23] A RIN may be used to demonstrate compliance during the calendar year in which it is generated, or the following calendar year (for up to 20% of an obligated party's RVO). Thereafter, the RIN is considered to be "expired" and cannot be used for compliance purposes.[24] Obligated parties meet their RFS obligations by accumulating RINs and "retiring" them in an annual compliance demonstration.[25] The statute and regulations also provide that, in lieu of retiring the requisite number of RINs to show compliance for a particular year, an obligated party may choose to carry a RIN deficit into the following year under certain conditions.[26] An obligated party may carry forward a RIN deficit equal to its full or partial RFS obligation.

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[17] CAA section 211(*o*)(3)(B)(ii)(I).
[18] 40 CFR 80.1406. For simplicity this document focuses on refiners; however, the same concepts of RIN costs, RIN cost passthrough, and RIN discount for blended fuel also apply to importers.
[19] CAA section 211(*o*)(5)(A)-(C).
[20] 40 CFR 80.1426(a).
[21] 40 CFR 80.1426(e).
[22] 40 CFR 80.1429(b).
[23] 40 CFR 80.1425-29.
[24] 40 CFR 80.1427(a)(6), 80.1428(c), & 80.1431(a).
[25] 40 CFR 80.1427(b).
[26] CAA section 211(*o*)(5)(D), 40 CFR 80.1427(b).

The price of the RIN is expected to reflect the marginal difference between the supply price for the renewable fuel and the demand price for the renewable fuel, which is the price the market is willing to pay for the renewable fuel as a transportation fuel.[27] In other words, if it costs more to produce the renewable fuel than consumers are willing to pay for the renewable fuel, the RIN price would be expected to match that cost difference so that, in the end, the fuel price for consumers is the same. The price of the RIN, therefore, allows the "discount" on the renewable fuel necessary to have the market consume the renewable fuel. This dynamic functions to incentivize blending and use of renewable fuel up to the mandated volume even if the market demand price for the renewable fuel would not cover the cost of its production. In this way, the RIN price facilitates greater use of renewable fuel as the RFS program was designed to do.

The design of the RIN trading system enabled parties that were already producing and blending renewable fuel to continue to do so. They could then sell excess RINs to obligated parties that lacked blending capability. This open trading market for RINs provides three main benefits. First, it allows all obligated parties, regardless of size or situation, equal ability to comply with their RFS obligations immediately without having to invest capital or resources. They can contract with others already providing the services and/or go into the open market to acquire RINs. Second, this system averts the need for each individual obligated party to purchase and blend renewable fuel into its own gasoline and diesel fuel.[28] Thus, the program was designed to "preserve[] existing business practices for the production, distribution, and use of both [petroleum] and renewable fuel."[29] Third, it levels the playing field for the cost of compliance, with all obligated parties having access to the RINs needed for compliance at the same cost, regardless of whether they acquire the needed RINs by purchasing them on the open market or by blending renewable fuel themselves. The RFS program, through the RIN system, was designed to avoid creating DEH based on whether compliance is obtained through blending of renewable fuel or through purchasing of RINs.

C. RFS Compliance and RIN Market Dynamics

Congress structured the RFS program to impose proportional requirements on all obligated parties, including small refineries. The RFS obligations are established as a percentage of an obligated party's production;[30] therefore, by definition, the obligation is proportional to the quantity of gasoline and diesel fuel that party produces or imports each year.[31] Obligated parties must acquire RINs to meet their RFS obligations,[32] either through their own blending of

[27] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA, May 14, 2015 [hereinafter, "the Burkholder memo"].
[28] Complying with such a requirement would have been difficult, if not impractical for obligated parties, as different renewable fuels are blended into gasoline and diesel fuel and pipeline operators normally do not allow gasoline or diesel fuel containing renewable fuel to be transported through their pipelines.
[29] "RFS1 Summary and Analysis of Comments," EPA-420-R-07-006 at 1-6, April 2007.
[30] *See supra*, Sections II.A and B.
[31] *See* CAA section 211(*o*)(3)(B); 40 CFR 80.1407.
[32] For purposes of the RFS program, transportation fuel is defined as "fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines (except fuel for use in ocean-going vessels)." 40 CFR 80.1401. The regulations at 40 CFR 80.1406 establish that "[a]n obligated party is any refiner that produces gasoline or diesel fuel

renewable fuel or through the purchase of RINs from other parties that produce or blend renewable fuel. Obligated parties must demonstrate compliance annually by retiring RINs requisite with their RFS obligations.

The cost of acquiring RINs is the same for all parties regardless of whether the RINs needed to comply are acquired by blending renewable fuel or by procuring RINs from others.[33] This occurs through the phenomena of RIN discount and RIN cost passthrough, introduced in the Executive Summary and explained in detail throughout this document. Parties that blend more renewable fuel than they need to satisfy their RFS obligations may show an apparent revenue source from the sale of those RINs. However, in the competitive fuels market, price competition prevents these parties from retaining the revenue from their RIN sales.[34] If parties that blend renewable fuel do not discount the price of their blended fuel by the market price of the RIN, then their blended fuel would be priced higher than the same fuel where the producer has discounted the fuel by the price of the RIN, and the non-discounted fuel would never sell. Therefore, in order to price their products competitively in the fuels market, parties that blend renewable fuel must reduce the price of their blended fuel by the price of the RIN (RIN discount). Thus, the revenue from the RIN sale is used to offset the discounted sales price of the blended fuel and is passed through to consumers through reduced market prices for the blended fuels. Moreover, the RFS program imposes the same cost on all parties that produce or import gasoline or diesel fuel nationwide,[35] so the market price for gasoline and diesel fuel increases to reflect this cost, much as it would increase in response to a new tax (RIN cost passthrough). This relationship between RIN prices and the market prices for blended fuels was first analyzed by EPA in 2015.[36]

In this document we refer to an obligated party's ability to recover the cost of the RINs it acquires for compliance as "RIN cost passthrough," since obligated parties are passing these costs through to consumers. We refer to the lower prices received for blended fuel (e.g., gasoline and diesel fuel blended with renewable fuel) enabled by the sale of RINs as "RIN discount," since the sale of the RIN allows blenders to discount the price of the blended fuel. We find that all types of obligated parties have the same cost to acquire RINs, and that all types of obligated parties recover these costs when they sell the gasoline and diesel fuel they produce or import at the market price (RIN cost passthrough). Further, we find that blenders use revenue from RIN

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within the 48 contiguous states or Hawaii, or any importer that imports gasoline or diesel fuel into the 48 contiguous states or Hawaii during a compliance period." The regulations at 40 CFR 80.1407 establish that, in practice, an RFS obligation is imposed only on gasoline and ultra-low sulfur diesel (ULSD) used in motor vehicles, nonroad engines, locomotives, and marine engines (historically called MVNRLM diesel fuel). Such gasoline and diesel fuel only incur an obligation if used in the RFS covered location as defined in 40 CFR 80.1401. Throughout this document we refer to fuel that incurs an RFS obligation (e.g., gasoline, diesel fuel) as "obligated fuel" and fuel that does not incur an RFS obligation (e.g., heating oil, jet fuel) as "non-obligated fuel."

[33] *See infra*, Section IV.D.2.

[34] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA, May 14, 2015.

[35] In this document, the term "nationwide" refers to the RFS "covered location," which the regulations at 40 CFR 80.1401 define as "the contiguous 48 states of the United States, Hawaii, and any state or territory that has received an approval from the Administrator to opt-in to the RFS program under §80.1443."

[36] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA, May 14, 2015.

sales to discount the price of blended fuel (RIN discount). We therefore conclude that compliance with the RFS program cannot cause a DEH for small refineries.[37]

D. History of SREs

A small refinery is defined by the statute as "a refinery for which the average aggregate daily crude oil throughput for a calendar year . . . does not exceed 75,000 barrels."[38] Both the original RFS statutory provisions enacted pursuant to Energy Policy Act (EPAct), and the current text of the statute as amended by the Energy Independence and Security Act (EISA), provided all small refineries an initial blanket exemption from their obligations under the RFS program until calendar year 2011.[39] Under EPA's regulations, exempt small refineries were required to notify EPA that they qualified for the temporary exemption by submitting verification letters stating their average crude oil throughput rate during the applicable qualification period.[40] Furthermore, EPA's regulations allowed for small refineries that had submitted verification letters to qualify for the original statutory exemption under EPAct to also qualify under the SRE provision in EISA. The small refineries were not required to re-certify their throughput to maintain eligibility under the amended RFS program. Further discussion of EPA's past and current interpretation of small refinery eligibility criteria is provided in Section IV.A.[41]

The CAA includes two additional provisions regarding extensions of the small refinery exemption for the period after the initial blanket exemption expired:

1) Under the first statutory mechanism, applicable to 2011 and 2012, if DOE determined, through a study mandated under the CAA, that compliance with the RFS requirements would impose DEH on a small refinery, EPA was required to extend the small refinery's exemption by at least two years.[42] In 2009, DOE completed its study and found that, in a liquid and competitive RIN market, compliance with the RFS requirements would *not* impose DEH on any small refinery. Subsequently, some members of Congress directed DOE to revisit the 2009 DOE Small Refinery Study (hereinafter "the 2009 DOE Study") and in so doing to solicit input from the small refineries themselves.[43] In 2011, DOE completed a second study that used the small refinery input to develop a set of financial and operational metrics intended to inform DOE whether a small refinery was likely to experience DEH. Contrary to the 2009 DOE Study, the 2011 DOE Small Refinery Study (hereinafter "the 2011 DOE Study")[44] did not assume that RFS compliance costs would be the same for all refineries in a competitive market, and instead, assumed that small

[37] The economic theory supporting EPA's findings on RIN cost passthrough and the RIN discount, the market data we have evaluated in reaching these findings, and more detailed explanations on how various parties in the fuels market are affected by the RFS program are discussed in greater detail in Section IV.D.2.
[38] CAA section 211(*o*)(1)(K).
[39] CAA section 211(*o*)(9)(A)(i).
[40] 40 CFR 80.1441(b).
[41] 40 CFR 80.1441(e)(2)(i); EPA, *Financial and Other Information to be Submitted with 2016 RFS Small Refinery Hardship Exemption Requests*, December 6, 2016.
[42] CAA section 211(*o*)(9)(A)(ii)(II).
[43] Senate Report 111-45, at 109 (2009).
[44] "Small Refinery Exemption Study, An Investigation into Disproportionate Economic Hardship," Office of Policy and International Affairs, U.S. Department of Energy, March 2011.

refineries could face higher compliance costs by purchasing RINs when compared to large integrated refiners that would acquire RINs through blending. Furthermore, neither study considered the possibility that refineries would recover the cost of RINs through higher prices for their products.[45] DOE organized the metrics into a two-part matrix with sections addressing "disproportionate impacts" and "viability impairment."[46] DOE also developed a scoring protocol for the matrix that required the score in both sections of the matrix to exceed an established threshold for DOE to find that DEH existed at a given refinery. Using this regime, the 2011 DOE Study found that DEH existed at 14 small refineries, but again, assumed the refineries did not recover RIN costs and did not address the cause of the hardship. As required by the statute, EPA granted those small refineries a two-year extension of the original exemption (through 2012).

2) The second statutory mechanism provided that small refineries "may at any time petition the Administrator for an extension of the exemption in [section 211(*o*)(9)(A)] for the reason of [DEH]."[47] The Supreme Court recently opined on the meaning of "extension" in the context of CAA section 211(*o*)(9)(B), overturning a holding by the U.S. Court of Appeals for the Tenth Circuit that required a small refinery to have continuous exemptions to be eligible for further exemption extensions.[48] The Act directs EPA to evaluate such petitions "in consultation with the Secretary of Energy[.]"[49] EPA is also to "consider the findings of the study under [CAA section 211(*o*)(9)(A)(ii)(I)] and other economic factors."[50] After DOE conducted its 2011 Study and EPA granted two-year extensions to the 14 refineries the study identified, additional refineries came forward to EPA to seek exemptions for 2011 and 2012. EPA shared these new petitions with DOE, which applied the matrix scoring methodology developed in the 2011 DOE Study and shared the scoring results with EPA. EPA chose to satisfy the statutory requirements for consultation and consideration of the DOE Study by using DOE's scoring results in its evaluation of each SRE petition. Consistent with the extensions of exemptions it granted to the 14 small refineries through the 2011 DOE Study, EPA then decided to grant an extension of the exemption to an additional ten small refineries for 2011, and to nine for 2012. Since 2013, EPA has shared all incoming SRE petitions with DOE, and DOE has continued to make recommendations to EPA based on its scoring matrix, which does not assess the degree to which small refineries recover the RFS compliance cost in higher prices for their refined products (i.e., it does not consider RIN cost passthrough).

In the years since 2013, DOE and EPA have changed their treatment of the scoring matrix several times as informed by direction from members of Congress, judicial review, and changing administration policies. For DOE, the most significant change in approach did not involve the matrix evaluation or the scoring methodology, but rather modified the recommendation DOE provided to EPA for a given score on the matrix (i.e., DOE implemented the direction from Congressional report language to recommend 50% exemptions, as opposed to

[45] *See infra*, Section IV.D.
[46] 2011 DOE Study at 32-36.
[47] CAA section 211(*o*)(9)(B)(i).
[48] *See HollyFrontier*, 114 S.Ct. at 2181. Consistent with that decision, small refineries that have not received continuous exemptions remain eligible to petition for future exemptions.
[49] CAA section 211(*o*)(9)(B)(ii).
[50] *Id.*

exclusively 0% or 100%, as described further below). For EPA, the changes involved the weight EPA afforded DOE's recommendation relative to the "other factors" EPA considered when evaluating SRE petitions. However, in none of these years did EPA require small refineries to demonstrate that they faced RFS compliance costs that were higher than for other obligated parties (i.e., disproportionate), nor did EPA require a demonstration that the hardship was caused by compliance with the RFS program, including an explanation for how compliance costs harmed them in a market characterized by RIN cost passthrough.

In some prior decisions, DOE and EPA concluded that DEH existed only when a small refinery experienced both disproportionate impacts and viability impairment, as measured by the matrix. In response to concerns that the two agencies' threshold for establishing DEH was too stringent, Consolidated Appropriations Act report language directed DOE to recommend 50% relief when a small refinery's score on either section of the matrix exceeded the applicable threshold.[51] Subsequent Senate Report language directed EPA to follow DOE's recommendation, and to report to Congress if it did not.[52]

The Congressional direction, along with changing administration policies, prompted EPA to change its approach to finding DEH at a small refinery. Whereas EPA had previously exercised discretion in evaluating "other economic factors" in its analysis of a small refinery's petition, EPA changed its approach to rely on DOE's recommendation and began granting a full exemption whenever DOE findings indicated that the small refinery could receive at least 50% relief, based on its matrix score.[53] Under this approach, EPA exempted small refineries from their RFS obligations solely based on this DOE finding, which was based on metrics that did not account for RIN cost passthrough. Thus, neither EPA nor DOE required any demonstration that the DEH experienced by the small refinery was due to the RFS program. Nor did EPA reconcile this reasoning with EPA's own finding that the costs of RINs used for compliance with the RFS program are the same for all obligated parties and passed through by all obligated parties to consumers (RIN cost passthrough).

EPA's approach to evaluating SRE petitions has been challenged several times by small refineries and other parties in different U.S. Courts of Appeals, as well as in the Supreme Court

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[51] Consolidated Appropriations Act, 2016, Pub. L. No. 114-113 (2015). The Explanatory Statement is available at 161 Cong. Rec. H9693, H10105 (daily ed. Dec. 17, 2015): "If the Secretary finds that either of these two components exists, the Secretary is directed to recommend to the EPA Administrator a 50 percent waiver of RFS requirements for the petitioner."

[52] Senate Report 114-281, 71 ("When making decisions about small refinery exemptions under the RFS program, the Agency is directed to follow DOE's recommendations which are to be based on the original 2011 Small Refinery Exemption Study prepared for Congress and the conference report to division D of the Consolidated Appropriations Act of 2016. Should the Administrator disagree with a waiver recommendation from the Secretary of Energy, either to approve or deny, the Agency shall provide a report to the Committee on Appropriations and to the Secretary of Energy that explains the Agency position. Such report shall be provided 10 days prior to issuing a decision on a waiver petition.").

[53] We note that under this approach, EPA granted full SREs to some very profitable refineries. A substantial number of small refineries that showed no viability impairment on the matrix received a 50% waiver finding from DOE, based only on the small refinery's disproportionate impacts score.

of the United States.[54] The approach to evaluating DEH we propose in this action is informed by the outcome of litigation filed in the U.S. Court of Appeals for the Tenth Circuit Court in 2018. Biofuels groups led by the Renewable Fuels Association (RFA) challenged EPA's actions in granting three individual SREs, and the affected small refineries intervened on EPA's behalf.[55] The court vacated and remanded EPA's actions for three reasons. First, under the Tenth Circuit's reading of the CAA, a small refinery would be eligible for SRE relief only if it has received extensions of the initial exemption in every year since 2010.[56] Second, the court found that EPA may grant relief only when it finds that the small refinery would suffer DEH due to compliance with the RFS program and not due, even in part, to other factors.[57] Third, the court held that EPA had acted arbitrarily and capriciously by failing to explain how granting the exemptions was consistent with the Agency's longstanding findings on RIN cost passthrough.[58]

After the Tenth Circuit's *RFA* opinion, the small refinery intervenors petitioned the Supreme Court for a writ of certiorari, appealing only the Tenth Circuit's holding that, in order to be eligible for exemption, a small refinery needed a continuous, uninterrupted exemption history.[59] The Supreme Court granted the writ of certiorari and reviewed the Tenth Circuit's holding. EPA, which changed its prior litigation position, and RFA, filed briefs in opposition, arguing that the Court should uphold the Tenth Circuit's ruling. On June 25, 2021, the Supreme Court held that the term "extension" as used in CAA section 211(*o*)(9)(B) does not include a continuity requirement and reversed the Tenth Circuit opinion only on that issue.[60] The Supreme Court did not review the other two holdings in *RFA* as those were not appealed by the small refineries.

Since the Supreme Court issued its opinion in the *HollyFrontier* case, EPA has met with several of the petitioning small refineries in individual meetings, accepted additional supplemental information from the small refineries, made all petitioning small refineries aware that they have the opportunity to submit additional information to EPA for consideration, and conducted an open meeting among the small refineries, inviting them to participate and provide feedback. In this proposed action, we are again soliciting information from all interested parties to inform our final analysis and decision, especially seeking additional information that would support or refute the proposed finding that small refineries do not face disproportionate cost or economic hardship *caused* by compliance with the RFS program. We are also soliciting information demonstrating that the cost of compliance with the RFS program is the same for all obligated parties and passed on to consumers and that small refineries are not experiencing DEH caused by compliance with the RFS program.

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[54] *Hermes Consol., LLC v. EPA*, 787 F.3d 568 (D.C. Cir. 2015) (reversing EPA's action due to errors EPA admitted in calculating the small refinery's net income and net refining margins); *Lion Oil Co. v. EPA*, 792 F.3d 978 (8th Cir. 2015); *Sinclair Wyoming Refining Co. v. EPA*, 887 F.3d 986 (10th Cir. 2017); *Ergon-West Virginia, Inc. v. EPA*, 896 F.3d 600 (4th Cir. 2019) (*EWV-I*); *Ergon-West Virginia, Inc. v. EPA*, 980 F.3d 403 (4th Cir. 2020) (*EWV-II*); *Renewable Fuels Ass'n, et al. v. EPA*, 948 F.3d 1206 (10th Cir. 2020) (*RFA*).
[55] *RFA*, 948 F.3d 1206 (10th Cir. 2020).
[56] *RFA,* 948 F.3d at 1244-49.
[57] *Id.* at 1253-54.
[58] *Id.*
[59] Pet. for Writ of Certiorari at (i), *HollyFrontier*.
[60] *HollyFrontier*, 141 S.Ct. at 2183.

III. EPA's Proposed Approach to Determining DEH When Evaluating SRE Petitions

Section 211(*o*)(9)(B)(i) of the CAA authorizes the EPA Administrator to temporarily exempt small refineries from their RFS obligations for the reason of DEH. The statute directs EPA, in consultation with DOE, to consider the DOE Study and "other economic factors" in evaluating SRE petitions. The statute does not define "disproportionate economic hardship" and identifies no particular "economic factors" to be considered, giving EPA "substantial discretion" for purposes of implementing these exemption provisions.[61] EPA, however, must interpret these provisions in a reasonable manner, consistent with the purpose of the statutory provisions at issue.

EPA's previous approach to interpreting these statutory provisions and evaluating SRE petitions was that a small refinery could receive an exemption from its RFS obligations by demonstrating it was experiencing DEH for any reason, including reasons unrelated to RFS compliance.[62] In this action, EPA is proposing to change its approach to require the small refinery to demonstrate that compliance with the RFS program is the cause of the DEH experienced by the small refinery. EPA has previously performed analyses, and reviewed academic studies, on the RIN market that verify the passthrough of RFS compliance costs to consumers. However, our prior approach to evaluating SRE petitions did not rely on a showing that DEH was caused by RFS compliance because we concluded that our consideration of "other economic factors" extended beyond economic factors addressing DEH caused by RFS compliance. The Tenth Circuit in *RFA* clarified that EPA's prior approach was contrary to the language of the CAA authorizing exemptions only due to DEH *caused by* compliance with the requirements of the RFS program.[63] Under the approach we propose here, the small refinery must demonstrate a direct causal relationship between its RFS compliance costs and the DEH it alleges; assertions regarding other real but unrelated financial difficulties the refinery may be experiencing would not satisfy this requirement. Additionally, the small refinery must demonstrate how its specific RFS compliance costs are disproportionate compared to other refineries' RFS compliance costs and are of sufficient magnitude to warrant the exemption. EPA has weighed several considerations in proposing this new approach and this interpretation is consistent with the language of the Act, the purpose of the SRE provision, and is the most reasonable approach for implementing the RFS program.[64]

Our change in approach is primarily informed by the *RFA* opinion, which laid out a rationale for its conclusion that the statutory provisions require DEH to be caused by RFS compliance.[65] Additionally, the court in *RFA* held that EPA had acted arbitrarily and capriciously when the Agency ignored the relevant evidence and granted three SREs without addressing its long-standing position that RIN costs are passed through by refineries and

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[61] *Hermes*, 787 F.3d at 575 ("The statute gives no further instruction and identifies no particular economic factors or metrics to be considered. That sort of statutory silence about the particular factors that an agency must consider conveys 'nothing more than a refusal to tie the agency's hands' (internal citation omitted). As long as EPA consults with DOE and considers the 2011 Study and 'other economic factors,' EPA retains substantial discretion to decide how to evaluate hardship petitions.").
[62] *See supra*, Section II.D.
[63] *RFA*, 948 F.3d at 1253-54.
[64] *See infra*, Section IV.D.1.
[65] *Id.*

ultimately borne by consumers. After review of the court's decision, EPA agrees that these holdings both reflect a reasonable interpretation of the Act and comport with EPA's longstanding conclusions regarding RIN cost passthrough.[66]

Using this new approach, we evaluated the information and data available to us to assess whether any of the petitioning small refineries demonstrated DEH. The very market-based design of the RFS program with the RIN system for compliance has equalized the cost of compliance among all market participants, making it highly unlikely any one refinery would face a disproportionate cost of compliance.[67] We have evaluated an extensive amount of data and available literature, and our analysis shows the cost of RINs is the same whether refineries acquire the RINs by blending renewable fuel or by buying RINs on the open market.[68] The data and available literature also informed our finding that the RFS compliance cost is passed through in the price of refined products. Therefore, considering all of this information and analysis as more fully explained in later sections of this document, we are proposing to find that no small refinery experiences DEH due to their compliance with the RFS program.

When an agency changes its position, it must "provide a reasoned explanation for its action" and "display awareness that it is changing position."[69] Furthermore, EPA does not need to show "that the reasons for the new policy are *better* than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates." (emphasis in the original).[70] This proposed approach is reasonable as it is supported by the language and construction of the CAA and data analyses performed by EPA and independent parties.[71] For the reasons described herein, EPA believes that this approach is the most logical interpretation of the statutory provisions and the most reasonable way to implement the SRE program.

IV. EPA Evaluation

A. Eligibility to Petition

In this action, we are proposing to find two refineries ineligible to petition for an SRE. One refinery is ineligible because its throughput exceeded 75,000 bpd in the petitioning year and the prior year and because it did not receive the initial exemption. The second refinery is ineligible because the refinery did not receive the initial exemption.

In this action, we are proposing to revert to our prior approach to eligibility to petition for an SRE on the basis of having received the initial exemption. We are proposing to read the

[66] *See infra*, Section IV.D.2.
[67] *See supra*, Section II.B.
[68] *See infra*, Section IV.D.2.
[69] *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009).
[70] *Id.* (emphasis in the original).
[71] *See infra*, Section IV.D.

statute such that only small refineries that received the initial blanket exemption are eligible to petition for an extension of that initial exemption.[72]

1. Definition of Small Refinery

As part of EPAct, Congress defined a small refinery as "a refinery for which the average aggregate daily crude oil throughput for a calendar year (as determined by dividing the aggregate throughput for the calendar year by the number of days in the calendar year) does not exceed 75,000 barrels."[73] This definition was maintained in EISA.[74] These definitions informed EPA's implementing regulations in 2007 and 2010, which similarly defined a small refinery as processing less than 75,000 bpd in 2004 and 2006, respectively, for purposes of determining eligibility for the initial blanket statutory exemption.[75] In 2014, EPA promulgated regulations related to eligibility and requirements for SRE petitions.[76] In these regulations, EPA modified the eligibility requirements such that small refineries qualified for exemptions based on their crude oil throughput for the petition year and the prior year.[77] This means that, to qualify as a small refinery, a refinery must have processed no more than 75,000 bpd of crude oil in both the year for which the refinery requests an exemption and the prior year.[78]

2. Initial Blanket Statutory Exemption

In 2016, EPA deemed a refinery ineligible to petition for an exemption because the refinery did not exist in 2006, and, thus, could not have received the initial blanket exemption.[79] In that decision, EPA relied on the RFS regulations that state "a refiner may petition the Administrator for an extension of *its* small refinery exemption…." (emphasis added).[80] Additionally, EPA reasoned that "newer small refineries have the ability to consider whether they believe the establishment of the RFS program and its requirements will cause economic hardship before beginning operations." Beginning in 2017, EPA took a different approach to small refinery eligibility and granted exemptions for refineries that did not receive the initial exemption. We now propose to revert to the approach taken in 2016 – to be eligible to petition for an SRE, a refinery must have received the initial blanket exemption from the RFS program,

[72] We are maintaining our approach to size-based eligibility, such that only small refineries with an average aggregate daily crude oil throughput that does not exceed 75,000 barrels per day (bpd) for the calendar year they petition, and the prior year, are eligible to petition for an SRE. *See* CAA section 211(*o*)(1)(K), 40 CFR 80.1401, 40 CFR 80.1441(e)(2)(iii).
[73] CAA section 211(*o*)(1)(K); EPAct of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005).
[74] EISA of 2007, Pub. L. No. 110-140, 121 Stat. 1492 (2007).
[75] 40 CFR 80.1101, 80.1141(a)(1), 72 FR 23900 (May 1, 2007); 40 CFR 80.1401, 80.1441(a)(1), 75 FR 14670 (March 26, 2010).
[76] 79 FR 42128 (July 18, 2014).
[77] 40 CFR 80.1441(e)(2)(iii), "In order to qualify to an extension of *its* small refinery exemption, a refinery must meet the definition of 'small refinery' in §80.1401 for the most recent full calendar year prior to seeking an extension and must be projected to meet the definition of 'small refinery' in §80.1401 for the year or years for which an exemption is sought. Failure to meet the definition of small refinery for any calendar year for which an exemption was granted would invalidate the exemption for that calendar year" (emphasis added). *See also* 79 FR 42128 (July 18, 2014).
[78] 40 CFR 80.1401. We are not proposing to modify this regulation in this action.
[79] *See* Petition for Review, *Dakota Prairie Refining, LLC v. EPA*, No. 16-2692, at 8 of 17 (8th Cir. June 13, 2016).
[80] 40 CFR 80.1441(e)(2).

though a small refinery need not have had a continuous exemption since the original statutory exemption, consistent with the Supreme Court's holding in *HollyFrontier*.

3. Changed Approach to Eligibility

In this action, EPA is proposing to change its approach to SRE eligibility to require that a petitioning small refinery receive the initial statutory exemption through 2010 in order to qualify for an extension of the initial exemption under CAA section 211(*o*)(9)(B). We believe this policy aligns with the text of the CAA, which describes a small refinery's right "to at any time petition the Administrator for an extension of the exemption in subparagraph (A) for the reason of [DEH]."[81] Furthermore, we believe this policy aligns with policy interests of implementing the RFS program. This is particularly true since the exemptions would provide a significant windfall profit to the exempted small refinery.[82] Additionally, refineries that exceeded the 75,000 bpd throughput threshold in 2006 were not the intended recipients of the initial exemption for small refineries, and, thus, we are acting consistent with congressional intent by continuing to exclude these parties from receiving an SRE.

While the Supreme Court recently held that a small refinery need not have had a continuous exemption since the initial exemption, the Court's decision implies that an exemption must have existed at some point for it to be extended.[83] Regarding the definition of "extension," the Court agreed with the Tenth Circuit that, as used in CAA section 211(*o*)(9), the word has a temporal meaning (i.e., an extension of time), and not the alternative meaning of "extension" to grant or offer.[84] The Court, however, clarified that an extension may still be given after a lapse.[85] The Court applied several analogies to illustrate this, including that of a student requesting an extension of a deadline to submit a paper after the deadline has already passed.[86] Applying that analogy to a small refinery that did not receive the original exemption, but requests an extension of that exemption, would be like a student that was never in the class asking the professor for an extension of a deadline for a paper it was never assigned to begin with (i.e., there is no due date for the professor to extend just as there is no exemption period for EPA to extend). Thus, the language of the statute indicates that, without having received "the exemption under

[81] CAA section 211(*o*)(9)(B)(i).
[82] *See infra*, Section IV.D.2
[83] *See HollyFrontier*, 141 S. Ct. at 2177 ("It is entirely natural—and consistent with ordinary usage—to seek an "extension" of time even after some lapse."); *id.* at 2181 ("And fairly read, the key phrase at issue before us—'A small refinery may at any time petition the Administrator for an extension of the exemption under subparagraph (A) for the reason of disproportionate economic hardship'—simply does not contain the continuity requirement the court of appeals supposed."); *id.* at 2184 (Barrett, J. dissenting) ("Yet, HollyFrontier insists, the term "extension" is not *always* used that way. Instead, it might *sometimes* refer to a "non-continuous extension"—in other words, an extension of something that used to exist but no longer does. . . . [T]he Court concludes that Holly-Frontier's reading must be right—which means that EPA can provide an "extension" of an exemption that is no longer in effect.").
[84] *See supra*, Section II.D.
[85] *HollyFrontier*, 141 S.Ct. at 2177 ("Ultimately, however, we agree with the renewable fuel producers and the court of appeals that subparagraph (B)(i) uses "extension" in its temporal sense—referring to the lengthening of a period of time."). The *HollyFrontier* decision is further discussed in Section II.D.
[86] *Id.* at 2177-78.

subparagraph (A)," there is nothing for a small refinery to petition EPA to extend temporally.[87] Ergo, if a small refinery did not receive the original statutory exemption, it is ineligible to have EPA extend the duration of that exemption.[88]

4. Proposed Eligibility Determination for Two Petitioning Small Refineries.

EPA has received 2019 and 2020 SRE petitions from a refinery that exceeded the 75,000 bpd throughput limit in 2019, thereby making the refinery ineligible to petition for an SRE in both 2019 and 2020.[89] In this action, we propose to find this refinery ineligible to petition for an SRE in 2019 and 2020. In the alternative, even if the refinery were eligible to petition, we have reviewed the petitions and supplemental information supporting them and propose to find that the refinery did not demonstrate that it experienced DEH caused by its RFS compliance as described generally for all small refineries in Section IV.D.2.

EPA has received two 2019 and two 2020 SRE petitions from two refineries (including the one identified in the previous paragraph) that would be ineligible under the proposed changed approach described in Section IV.A.2 In this action, we propose to determine that these refineries are ineligible to petition for an exemption because these two refineries did not receive the initial exemption. In the alternative, even if the refineries were eligible to petition, EPA has reviewed the petitions and supplemental information supporting them and is proposing to find the refineries did not demonstrate that they experienced DEH caused by their RFS compliance described generally for all small refineries in Section IV.D.2.

B. Compliance with Petition Requirements

When submitting an SRE petition to EPA, the small refinery bears the burden of demonstrating that compliance with the requirements of the RFS program causes DEH for that small refinery. EPA regulations require that an SRE petition specify the factors that demonstrate a "disproportionate economic hardship," provide a detailed discussion regarding the hardship the refinery would face in complying with the RFS requirements, and identify the date the refinery anticipates that compliance with the RFS requirements can reasonably be achieved at the small refinery.[90] Since the Tenth Circuit issued its opinion in *RFA*, many small refineries have contacted EPA to supplement their original SRE petitions and to provide additional information about their financial situations. EPA greatly appreciates this information. EPA has completed a preliminary evaluation of the data and information provided in the SRE petitions to determine if any of the petitioners have demonstrated that the cost of compliance with the RFS is the cause of the DEH, and that such costs are not passed through by that small refinery to the consumer under the RIN cost passthrough principle.

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[87] *Id.* at 2181-82 ("Indeed, the dissent finds it "odd" that our reading would permit hardship relief only to small refineries in existence in 2008 and not to new ones, *post*, at 2189-2190…Nor is there anything odd about the fact that Congress chose only to protect existing small refineries rather than new entrants. Often Congress chooses to protect existing market participants from shifts in the law while applying new restrictions fully to future entrants.")
[88] We note that this issue was neither before the courts in *RFA* or in *HollyFrontier* because the three small refineries at issue in those cases all received the initial blanket exemption.
[89] 40 CFR 40.1441(e)(2)(iii).
[90] 40 CFR 80.1441(e)(2).

C. *DOE Consultation and EPA Consideration of the DOE Study and Other Economic Factors*

CAA section 211(*o*)(9)(A)(ii) required that EPA grant exemptions upon DOE's determination that a small refinery "would be subject to a disproportionate economic hardship."[91] Section 211(*o*)(9)(B), in contrast, provides that EPA must "consult[] with the Secretary of Energy," but does not dictate any particular action that EPA must take following consultation. It also does not provide any further direction on EPA's consultation with DOE, nor does it inform DOE on the form its consultation must take. In fact, "Congress placed no limits on how DOE should provide its consultation to EPA under [the RFS]."[92] This absence of direction provides "substantial discretion" to the agencies to determine how DOE will provide consultation for the pending SRE petitions.[93] Both agencies previously relied on DOE's findings through its application of the DOE scoring matrix to effectuate DOE's consultation on each SRE petition.[94] For this proposed action, EPA has consulted with DOE through discussions in meetings and phone conversations regarding the pending SRE petitions, the supplemental supporting information the small refineries provided, and the analysis and proposed determinations in this document.

In evaluating petitions for SREs under CAA section 211(*o*)(9)(B), EPA is directed to "consider the findings of the [DOE] study." DOE, in fact, conducted two studies, one in 2009 and an update to the study in 2011.[95] The original 2009 DOE Study concluded that small refineries would not face DEH from compliance with the RFS program given the proportional obligations of the program as a function of their gasoline and diesel fuel production and the opportunity for refineries to comply by blending or by purchasing RINs, provided that the RIN market proved to be liquid and competitive. The RIN market has developed to be open, competitive, liquid, and functioning as intended;[96] hence, the 2009 DOE Study accurately forecasted what was likely to occur given the highly competitive fuels market with which DOE was familiar.

When DOE expanded its study in 2011, it posited that small refineries could face DEH "*if* blending renewable fuel into their transportation fuel or purchasing RINs increase[d] their cost of products relative to competitors." (emphasis added).[97] DOE expressed a similar possibility another way noting, "*If* certain small refineries must purchase RINs that are far more expensive than those that may be generated through blending, this will lead to disproportionate economic hardship for those effected entities." (emphasis added).[98] Looking to a potential future where RIN prices rose significantly (as they have since done) DOE projected, "there are numerous circumstances when RIN prices could rise, increasing the cost of compliance and *perhaps* increasing the cost of compliance more for refineries that rely on RINs for compliance compared

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[91] *See supra*, Section II.D.
[92] *Hermes*, 787 F.3d at 577.
[93] *Id.* at 575.
[94] *See supra*, Section II.D.
[95] *See supra*, Section II.D.
[96] *See infra*, Section IV.D.2.
[97] 2011 DOE Study at vii.
[98] *Id.* at 2.

to those that do not." (emphasis added).[99] To make clearer the circumstances it was envisioning where such disproportionate costs *could* arise, DOE provided a detailed appendix, Appendix B, which laid out scenarios for three refiners in different circumstances relative to the RFS program.[100] The first case was a refiner that blends all its production with ethanol and does not have to purchase ethanol RINs. The second case was for a refiner that does not do any blending and must purchase RINs to meet all of its RVO. Finally, the third case was for a refiner with excess RINs to sell into the market. What Appendix B assumed was that the refiner that got its RINs through blending ethanol would get the RINs at nearly no cost, while the refiners that had to buy RINs would be forced to pay the higher market cost for compliance. In this way, DOE projected that some refineries *could* face a disproportionate cost of compliance. Through the matrices in its report, DOE evaluated whether those disproportionate costs rose to a level such that a refinery faced DEH due to those higher costs. DOE articulated bringing those two elements together thusly, "[d]isproportionate economic hardship must encompass two broad components: a high cost of compliance relative to the industry average, and an effect sufficient to cause a significant impairment of the refinery operations."[101] However, DOE did not assess in this study whether their assumptions that refiners bear different costs for RINs and that they may not be able to pass these costs on to consumers in the marketplace actually occurred.

A number of small refineries have stated to EPA that DOE's projection in the 2011 DOE Study is exactly what has come to pass. Ethanol (D6) RIN prices have risen significantly, and small refineries argue that they bear these higher RIN costs while integrated refiners (blenders) receive RINs at almost no cost. Further, they argue that these disproportionate costs are significant enough that they constitute DEH for the refineries just as DOE articulated. EPA has carefully reviewed data, contracts and other information from small refineries to evaluate if, as DOE posited in 2011, refineries that acquire RINs through blending get them at a lower cost than do refineries that purchase RINs on the open market.[102] What we have found is that the RIN discount phenomenon applies—blenders, in fact, discount their sales price for E10 by the market price of the RIN (i.e., the sales price of E10 reflects the cost to buy ethanol minus the market price for selling the RIN). Hence, while the blender gets the RIN for "free" when it purchases a gallon of ethanol, it has to discount the price of that ethanol when sold as E10 by the full current market price of the RIN. This means the blending refinery pays the full market cost of the RIN through the discount it gives in the price of the E10 it sells. The 2011 DOE Study did not consider that blending refineries would have to discount blended fuel by the price of the RIN, and hence, projected a potential outcome in finding DEH that has not occurred in practice. Rather, as the 2009 DOE Study anticipated, the competitive market forces have resulted in the same cost of compliance whether that cost comes in the purchase of RINs on the open market or through the discounting of the price blended fuel sold by blenders. Neither the 2009 DOE Study nor the 2011 DOE Study anticipated the even more significant finding that, without regard to how refineries experience the RFS compliance cost, the RIN cost passthrough phenomenon applies—refineries pass those higher costs through to their customers in higher prices for the refined products they sell.

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[99] *Id*. at 3.
[100] *Id*. at B-4.
[101] *Id*. at 3.
[102] *See infra*, Section IV.D.2.

For the reasons described above and after considering the "other economic factors" described in Sections IV.D.2 and 3, we propose to find small refineries do not face disproportionate costs to comply with RFS. Further, we propose to find there is no economic harm, much less a hardship significant enough to impair refinery operations, that qualifies as DEH caused by RFS compliance. For these reasons, we propose to find, consistent with the broad criteria for relief described in the 2009 and 2011 DOE Studies, that DEH is not demonstrated in the petitions EPA has evaluated.

D. Hardship Must Be Caused by RFS Compliance

1. The CAA Requires That DEH Must Be Caused by RFS Compliance

As discussed briefly above, the best reading of the statutory provisions at CAA section 211(*o*)(9) is that EPA's authority to grant an SRE "for the purpose of (DEH)" requires that the hardship be caused by RFS compliance. This interpretation aligns with both the statutory text and the purpose of the RFS program and the exemption.

a. The Text of the Statute Provides That DEH Must Be Caused by Compliance with the RFS Program

EPA did not require that DEH be caused by compliance with the RFS program in prior decisions to grant SREs.[103] On January 24, 2020, the Tenth Circuit in *RFA* held that the EPA only has the authority to grant SREs when the refinery experiences DEH caused by the RFS program.[104] The court pointed to statements in the three decision documents at issue indicating that relief from the RFS obligations could relieve the refinery's hardship "in whole or in part," and concluded that granting relief on the basis of something other than DEH caused by RFS compliance was impermissible.[105] We have evaluated the court's opinion and the text of the statute, and, going forward, we propose to require that the petitioning small refineries demonstrate that DEH is caused by RFS compliance as discussed further in this section.

The CAA's SRE provision is structured in two sections. Section "(A) Temporary exemption" provides the blanket exemption to all small refineries through 2010 and then lays out the conditions in which a small refinery may receive an extension of the initial exemption based on the DOE study. Section "(B) Petitions based on [DEH]" addresses ongoing case-by-case SRE petitions and how EPA must evaluate those petitions.

Section A refers to the "requirements of paragraph [211(*o*)(2)]," which provides, among other things, the applicable annual volume targets for the required categories of renewable fuel. The "requirements of paragraph [211(*o*)(2)]" are utilized in describing what an exemption means: "The requirements of paragraph [211(*o*)(2)] shall not apply to small refineries until calendar year 2011,"[106] as well as identifying the subject of the DOE's study: "[T]he Secretary of Energy shall conduct for the Administrator a study to determine whether compliance with the

[103] *See supra*, Section III.
[104] *RFA*, 948 F.3d at 1254.
[105] *Id.*
[106] CAA section 211(*o*)(9)(A)(i).

requirements of paragraph [211(*o*)(2)] would impose a [DEH] on small refineries."[107] It also describes the basis under which an exemption can be extended: "[i]n the case of a small refinery that the Secretary of Energy determines under subclause (I) would be subject to a [DEH] *if required to comply with paragraph [211(o)(2)]*, the Administrator shall extend the exemption under clause (i) for the small refinery for a period of not less than 2 additional years." (emphasis added).[108] These references to paragraph 211(*o*)(2) indicate a direct link between the RFS requirements and DEH. Thus, the best reading of the statutory language is that compliance with the RFS program must be the impetus for DEH warranting an SRE under section A, meaning that a small refinery may not simply experience a year of poor economic performance or struggle with disadvantageous operational or market constraints to merit an SRE. Nor can a refinery rely on unplanned events like a fire, natural disaster, or planned events such as paying out stock dividends or other capital purchases/loans to qualify for relief from its RFS obligations.[109] Rather, section A of the SRE provision provides that DEH must be caused by the small refinery's compliance with the requirements of the RFS program.[110]

Section B of the SRE provision states that a small refinery may "at any time petition the Administrator for an extension of the exemption *under subparagraph (A)* for the reason of [DEH]."[111] By making any ongoing SREs mere "extension[s] of the exemption under subparagraph (A)," Congress carried over the causal requirement in section A to section B.[112] While section B uses the language "for the reason of [DEH]" without a modifying clause tying it to compliance with the RFS program, section B cannot be read outside of the context of section A; section B is merely providing an opportunity for small refineries to request continuation of the exemption in section A. Therefore, the causal requirement in section A tying DEH to RFS compliance applies to section B as well. Additionally, it is section A that provides the basis on which DEH must be founded: compliance with the RFS program. Thus, even if the exemption under section B could be interpreted as a distinct exemption from the exemption under section A, it must be "for the reason of [DEH]" as defined in section A as being "impose[d]" by, or existing "if [a small refinery was] required to comply with" its RFS obligations. In this way, the use and meaning of "disproportionate economic hardship" is the same in both sections A and B. Therefore, we agree with the Tenth Circuit that the "language of these provisions indicates that renewable fuels compliance must be the cause of any disproportionate hardship."[113] As described above, EPA believes this is the best interpretation of the inter-related provisions of CAA sections 211(*o*)(9)(A) and (B) and is therefore proposing to adopt this interpretation going forward.

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[107] CAA section 211(*o*)(9)(A)(ii)(I).
[108] "In the case of a small refinery that the Secretary of Energy determines under subclause (I) would be subject to a [DEH] if required to comply with paragraph [211(*o*)(2)], the Administrator shall extend the exemption under clause (i) for the small refinery for a period of not less than 2 additional years." CAA section 211(*o*)(9)(A)(ii)(II).
[109] *RFA*, 948 F.3d at 1254. ("Granting extensions of exemptions based at least in part on hardships not caused by RFS compliance was outside the scope of the EPA's statutory authority.")
[110] *Id.*
[111] CAA section 211(*o*)(9)(B)(i) (emphasis added).
[112] *RFA*, 948 F.3d at 1253.
[113] *Id.*

b. The Purpose of the RFS Program Supports a Requirement That DEH Must Be Caused by Compliance with the RFS Program

Requiring that DEH be caused by RFS compliance also furthers the purpose of the RFS program, which exists to encourage the use of renewable fuel. Historically, SREs have resulted in reductions in the volume of renewable fuel used in the United States.[114] In general, hardship provisions exist to provide particular parties additional time to come into compliance with new regulations if they are expected to or are facing difficulties adjusting to a new regulatory requirement. This is historically how EPA has designed and implemented hardship provisions for other fuels programs, often with phase-out provisions (i.e., only available for a set number of years after implementation).[115] Therefore, it is logical to interpret the SRE provision to also provide initial time for small refineries to come into compliance, with the expectation that they would do so, and would only be eligible for an extension of the exemption if they suffered hardship specifically due to the RFS program itself.[116]

Additionally, allowing relief from RFS obligations for hardship completely unrelated to the RFS program would be an inappropriate use of an exemption provision, particularly one where the text of the statute requires demonstration of a causal relationship between the hardship and the program. Had Congress intended that EPA provide relief for hardship due to something other than the RFS program, the statutory language likely would have been more explicit in providing such broad authority. It would be illogical for the "temporary hardship" provision to have been established as an opportunity to prop up businesses and provide relief for reasons wholly unrelated to the RFS program, the program from which it is providing relief. It would only make sense that, in implementing the RFS program, we provide relief from impacts of the RFS program that result from the RFS program itself. It is hard to imagine that Congress intended the SRE provision be used to cure the financial distress some small refineries may otherwise face, especially when other legal and policy options exist to provide compliance flexibility, and, significantly, when that distress may be caused by a broad array of circumstances unrelated to the RFS program, ranging from difficult geography to adverse business decisions. Finally, the granting of SREs in light of RIN cost passthrough means that exempted small refineries are not only relieved of their RFS obligations, but also get a financial *benefit* through the sale of RINs obtained through blending, or through the sale of their petroleum fuel that includes the value of the RIN.[117] This windfall to small refineries does not further the goals of the RFS program, and only provides a disproportionate net benefit to small refineries granted exemptions in comparison to other refineries that are either ineligible to petition for exemption or are denied an exemption on the lack of merit of their petition.[118] Furthermore, when small refineries gain this benefit through exemption, RFS compliance is incrementally shifted to other

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[114] We acknowledge that beginning in 2020, we have projected the amount of SREs such that when the projections accurately reflect the volume of fuel exempted, the volume of renewable fuel required under the RFS program is not reduced by the granting of SREs.

[115] *See*, e.g., the diesel fuel hardship provisions at 40 CFR 80.560(a), which effectively allowed a delay of up to four years in complying with EPA's diesel fuel sulfur standards.

[116] We note that such an approach is consistent with Congressional intent for the SRE provision, whether that intent is considered to be a "funnel to compliance" or a "safety valve," as considered by the Supreme Court in deciding *HollyFrontier*. *See HollyFrontier*, 141 S. Ct. at 2181-82.

[117] *See infra*, Section IV.D.2.

[118] *See*, e.g., Comments from API on 2020 RFS Annual Rule, Docket Item No. EPA-HQ-OAR-2019-0136-0721.

parties, which, in turn, pass on that increment in their compliance costs to consumers. In essence, the significant financial benefit of exemptions granted to small refineries is paid for by consumers in still higher transportation fuel costs.[119]

2. DEH and RIN Cost Passthrough

An additional part of the Tenth Circuit's holding was that EPA failed to explain how a finding of DEH comports with EPA's findings on RIN cost passthrough.[120] In this action, we are proposing to adopt an interpretation of the statute that DEH must be caused by compliance with the RFS program. It follows, then, that in making a finding of DEH we would have to explain how the RFS program could cause DEH for a small refinery in light of EPA's longstanding and consistent findings on RIN cost passthrough.

After reviewing the available data and analysis, including analyses conducted by EPA and outside parties, as well as data and analyses submitted by petitioning small refineries, we propose to find that all obligated parties recover the cost of acquiring RINs by selling the gasoline and diesel fuel they produce at the market price, which reflects these RIN costs (RIN cost passthrough). Further, we propose to find that blenders use the revenue from RIN sales to discount the price of the blended fuel they sell (RIN discount). We further propose to find that, since refining and fuel blending markets are highly competitive, the RFS obligation is the same for every gallon of gasoline and diesel fuel, RINs are widely available in an open and liquid market, and the cost of acquiring RINs is the same for all parties, all types of obligated parties bear the same cost from compliance with the RFS program as these aspects of the RFS program and the RIN market facilitate the RIN cost passthrough and the RIN discount principles discussed above. While some parties dispute EPA's findings on RIN cost passthrough and the RIN discount, those same parties have not made business decisions over the last decade that would be logical if RIN cost passthrough and RIN discount were not occurring. For example, if RIN cost passthrough did not exist, we would expect to see refiners avoiding RFS obligations by shifting production to non-obligated fuel (e.g., heating oil, jet fuel) and/or export fuel. We would also expect to see actions to expand or modify their business models to include additional blending of renewable fuel to reap the alleged rewards that they claim independent blenders and marketers enjoy.[121] Taken together, we propose to conclude that the RFS program does not impose a DEH on small refineries.

Assessing the impact of the RFS program on refiners and blenders is complicated for several reasons. First, many parties may operate in several different roles, such as merchant refiners, integrated refiners, and blenders, in any given year.[122] Second, the impact of RIN costs

[119] In the 2020 RFS Annual Rule, EPA finalized regulations that shift the projected exempted volumes for small refineries to the remaining obligated parties instead of reducing the renewable fuel volumes as had been common practice in prior years. 85 FR 7016 (February 6, 2020).
[120] *RFA*, 948 F.3d at 1256-57.
[121] There has been an expansion of independent gasoline blenders and marketers in recent years. We anticipate this trend will continue. This is driven by the gasoline market being oversupplied, making it economical for companies to invest in blending and purchase gasoline blendstocks on the spot market. The typical fraction of a cent return is sufficient to offset capital investments in blending infrastructure. The market dynamic has swung back and forth over the decades independent of the RFS program and RIN costs.
[122] *See infra*, Section IV.D.2.c.

on the price of fuels is not often apparent in the market pricing data.[123] Third, while market prices for renewable fuel with RINs attached are readily available in posted prices, renewable fuel is less commonly traded without RINs and hence prices of renewable fuel without the RIN are also rarely available outside of contracts between parties that are claimed as confidential.[124] Finally, terminology and accounting practices vary between different parties, often making apples to apples comparisons difficult.[125]

In this section, we present the data and analysis to support our proposed findings that small refineries do not suffer DEH from their RFS obligations because RIN costs are fully passed through to consumers. Further, we show that any such RFS compliance costs are not disproportionate because the cost to acquire RINs, whether via blending, or through the RIN market, are the same, making the costs of RIN acquisition the same for all parties. First, we provide a brief description of prior publications on RIN cost passthrough and the RIN discount. Second, we reiterate the general economic theory that supports the premises of RIN cost passthrough and the RIN discount. Third, we briefly discuss the different market participants, and how we expect their operations to be affected based on economic theory. Fourth, we analyze the most current data available to the Agency to determine whether the finished fuel and RIN markets move in the way the economic theory predicts.

Small refineries alleging DEH generally claim that: (1) They are unable to recover the cost of the RINs they purchase in the sales prices of the gasoline and diesel fuel they produce because of their geography or market position; and/or that (2) They face higher costs for acquiring RINs than their competitors (usually integrated refiners or non-obligated blenders) that acquire RINs by blending qualifying renewable fuel. In the first case, petitioners argue that they are unable to recover the added cost of RIN purchases needed for RFS compliance and/or that the market price for gasoline and diesel fuel does not fully reflect these costs. In the second case, petitioners argue that their competitors (non-obligated blenders and/or integrated refiners) do not have to discount the blended fuel they sell to consumers by the price of the RIN and, therefore, are able to acquire these RINs at a lower net cost than parties that purchase RINs. EPA has not found evidence to support either of these arguments, as shown by the data and analysis presented below. We note that the data we looked at in doing this analysis and the market behavior they describe are consistent across all the markets we observed.

a. Previous Assessments of RIN Market Dynamics

The degree to which the cost is "passed through" to consumers (RIN cost passthrough) and revenue from RIN sales is used to discount the price of blended fuel (RIN discount) has been a longstanding area of interest, especially since D6 RIN prices increased dramatically in 2013. EPA first published results of an assessment of obligated parties' ability to "pass through" RIN costs and the impact of RIN prices on the price of blended fuel in a technical memorandum in 2015.[126] EPA explained the economic principles at work that enabled obligated parties to recover

[123] *See infra*, Section IV.D.2.b.
[124] *See infra*, Section IV.D.2.d.
[125] *See infra*, Section IV.D.2.d.ii.
[126] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA, May 14, 2015.

their RIN costs through RIN cost passthrough and the discount of renewable fuel blends by the price of the RIN. EPA then examined several sources of market data to test those principles. We concluded that both the costs in refined products and discounts in blended fuel prices due to RINs were being fully passed through to consumers.

EPA next considered this issue in the context of petitions to reconsider the point of obligation in the RFS program.[127] While RIN cost passthrough was not the only topic at issue in our consideration of changing the point of obligation in the RFS program, the degree to which RIN costs and the RIN discount were passed through to consumers was a central argument in the various petitions. In considering these requests, EPA again examined available market data, as well as studies by outside parties and numerous public comments.[128] Once again, EPA concluded that the RIN costs and RIN discount were fully passed through to consumers and reflected in the market prices of petroleum fuel and blended fuel, and that blenders used revenue from RIN sales to discount the price of blended fuel. This decision was reviewed and upheld by the U.S. Court of Appeals for the D.C. Circuit.[129]

In evaluating the SRE petitions currently before the Agency, EPA has again evaluated the available market data. EPA has examined data through 2020 to determine whether more recent data continues to support EPA's views on the economic principles at play in the RIN market and whether these new data reconfirm our prior conclusions about both RIN cost passthrough and the RIN discount. EPA's prior analyses were generally based on publicly available data reported by the Energy Information Administration (EIA), which reports spot fuel prices for large fuels markets such as the New York Harbor or the Gulf Coast. Several small refineries claimed that, while RIN cost passthrough and the RIN discount may occur in these larger and more competitive fuels markets, RIN cost passthrough and the RIN discount were not occurring in the local markets into which these small refineries sold gasoline and diesel fuel. To assess these claims, EPA analyzed the data we received, including data sets provided by some of the small refinery petitioners located in smaller markets. The petitioners submitted the datasets to disprove EPA's conclusions on RIN cost passthrough. However, EPA found that the data, including the more recent data through 2020, either could not be used to draw conclusions regarding RIN market dynamics, or *supported* the conclusions that RIN costs are passed through in higher

[127] "Denial of Petitions for Rulemaking to Change the RFS Point of Obligation," EPA-420-R-17-008 at 21-31, November 2017.
[128] C.R. Knittel, B.S. Meiselman, & J.H. Stock, "The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard," Journal of the Association of Environmental and Resource Economists, 2017. C.R. Knittel, B.S. Meiselman, & J.H. Stock, "The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard: Analysis of Post-March 2015 Data," Working Paper. *See also* Letter from RaceTrac to Administrator McCarthy, August 17, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0014; Letter from QuikTrip to Administrator McCarthy, August 17, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0013; Presentation from Murphy USA to EPA, August 16, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0028.
[129] *Alon Refining Krotz Springs, Inc v. EPA*, 936 F.3d 628 (D.C. Cir. 2019). In its decision, the D.C. Circuit found that in determining whether refiners recover the cost of the RINs they purchase for RFS compliance, EPA "grounded that conclusion in studies and data in the record." *Id.* at 649. The D.C. Circuit also supported EPA's findings that there is a cost for integrated refiners and non-obligated blenders to acquire RINs, even if they do not purchase separated RINs, through lower prices for blended fuels. "In a competitive market there's no such thing as a free lunch, and blenders and integrated refiners pay their tab just as other do; they just do so indirectly. To offer finished fuel without attached RINs at a competitive price, these entities must discount their blended fuel by roughly the value of the RINs that they detach and kept for themselves." *Id.* at 650.

refined product prices and that blended fuel prices are discounted by the price of the RIN and, hence, passed through to consumers.[130] This means that no obligated party has a structural advantage or disadvantage from the RFS program. EPA found these conclusions held not only in the large fuels market previously assessed, but also in the smaller markets EPA examined using non-public market data, as well as the data submitted by the small refineries. Each of these assessments is discussed in further detail in the following sections.

b. Economic Principles of RIN Cost Passthrough

The market for gasoline and diesel fuel in the United States is extremely competitive at all levels, including the retail and wholesale levels. At the retail level, there are currently about 145,000 retail stations across the United States.[131] The majority of these stations are owned by parties that own fewer than ten retail stations, and, in many cases, only a single retail station.[132] All of these parties are selling fungible products (gasoline and diesel fuel) to a consumer base that is very sensitive to fuel prices, with prices posted on large signs making prices transparent. At the wholesale level, there are 129 petroleum refineries in the United States.[133] The market for renewable fuel and RINs is similarly very competitive. In 2020, more than 300 companies generated RINs for qualifying renewable fuel.[134] On average, approximately 5 billion RINs are traded between registered parties each month.[135] Prices for petroleum fuel, renewable fuel, and RINs are regularly reported by a variety of price reporting services.[136]

Refineries within the United States compete with each other, as well as with many other refineries overseas, and importers capable of sourcing gasoline and diesel fuel from a global fuels market. Low transportation costs for gasoline and diesel fuel, enabled by an extensive pipeline network, and the low cost of shipping these fuels via pipeline, barge, and petroleum tankers, mean that fuels markets across the United States are linked and that refiners are not only competing with other local refineries, but with parties across the country and in many cases the world. This can be seen clearly in the structure of many fuel supply contracts across the country that establish pricing based on the price of fuel at a major market (such as Houston or New York Harbor) plus or minus transportation costs between the local market and the major market,

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[130] *See infra*, Section IV.D.2.d.

[131] National Association of Convenience Stores, *Convenience Stores Sell the Most Fuel*, March 24, 2021, https://www.convenience.org/Topics/Fuels/Who-Sells-Americas-Fuel.

[132] *Id.* According to this data, 57.1% of retail fuel stations are owned by parties that own only one station, and an additional 3.8% of all retail fuel stations are owned by parties that own 2-10 retail stations.

[133] According to data from EIA, there were 129 operable refineries in the United States as of January 1, 2021 (EIA, *When was the last refinery built in the United States?*, Frequently Asked Questions (FAQs), June 25, 2021, https://www.eia.gov/tools/faqs/faq.php?id=29&t=6). Some of these refineries are located outside of the RFS covered location or do not produce gasoline or diesel fuel, and thus are not subject to the RFS program.

[134] The number of companies that generated RINs is from data accessed from EPA's Moderated Transaction System (EMTS).

[135] RIN trade and price information reported to EMTS is available at: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information.

[136] *See*, e.g., fuel price data from EIA (https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm) and RIN price data from EPA (https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information).

depending on the direction of product flow.[137] If a small refinery is facing competition in its local market from a larger remote market, the local price will typically be higher than the price in the major market, reflecting the cost of shipping the fuel to the local market from the larger remote market.[138] Conversely, if the small refinery is shipping its fuel to the larger market to sell, it will need to price its fuel below the remote market price to cover the cost of shipping the fuel to the remote market. Through thousands of decisions made by all the market participants each day, the prices between the markets equilibrate to the same level, offset by the transportation costs between the markets.

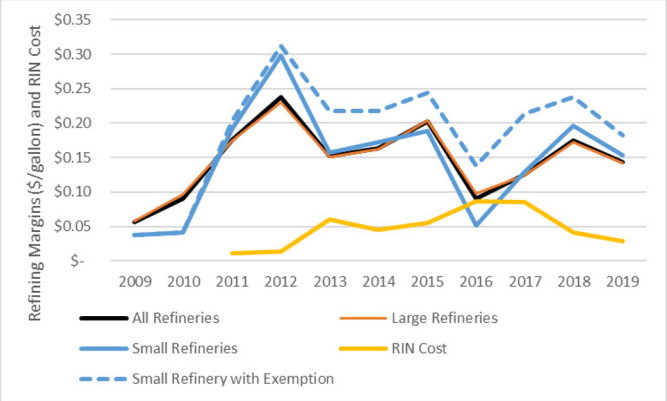
Economic theory suggests that in competitive markets like the fuels market, competitive market forces would drive market participants to pass through the costs and revenue from RINs to consumers in the prices of the products they sell. This means that higher RIN prices should not advantage any one group of refineries over another, and that RIN prices should not impact refining margins. As an initial assessment of the impact of RIN prices on refineries, EPA examined the refining margins for three groups of refineries—small refineries, large refineries, and all refineries—based on available public data (e.g., financial data from publicly traded companies) and confidential data, including data provided by petitioners. We compared these refining margins (operating profit per gallon of fuel produced) to the average RIN cost per gallon (the per gallon cost to acquire the RINs necessary to meet a refinery's RVO).[139] These data are presented in Figure IV.D.2.b-1. Consistent with the economic theory, we see no correlation between refining margins and RIN prices, nor do we see any indication that higher RIN prices put small refineries at an advantage or disadvantage relative to large refineries. Figure IV.D.2.b-1 also includes an estimate of the refining margin for small refineries if they received an exemption from their RFS obligations. The estimate was calculated by adding the RFS RIN compliance cost per gallon to the refining margins for small refineries each year, since exempting small refineries from their RFS obligations means they do not have to acquire RINs. This estimate demonstrates that exempting small refineries from their RFS obligations results in small refineries, as a class, having consistently higher refining margins than large refineries or the average of all refineries. This advantage is significant and increases as RIN prices increase.

[137] Several small refinery petitioners included examples of contracts, some of which were based on the fuel price at a larger fuel market plus (or minus) transportation costs. This information has been claimed as confidential by the petitioners.

[138] This is because the price in the local market will be set by the marginal supplier of fuel. In a market with both a local and remote supplier, the marginal supply price will be no lower than the fuel sourced from the remote market, which will include transportation costs.

[139] We calculated the RIN cost per gallon based on the RFS obligation and the average RIN prices for each year.

Figure IV.D.2.b-1: Refining Margins and RIN Costs (2009-2019)[a]



Data from SRE petitions and financial statements from publicly traded companies.
[a] The "Small Refinery with Exemption" line was calculated by adding the "RIN cost" line to the "Small Refineries" line. If a small refinery had already accounted for the financial benefit of an SRE in their reported margin for a given year, the effect would be to make the "Small Refinery with Exemption" line slightly less than shown for that year.

Understanding the impacts of the RFS program on the various parties that participate in the fuels market is complicated by the fact that different parties may participate in different activities within the fuels market. When analyzing the impact of the RFS program on the fuels market, we generally consider three different types of market participants: (1) Parties that produce and sell petroleum fuel, including blendstocks[140] (generally referred to as merchant refiners); (2) Parties that purchase petroleum fuel and renewable fuel, and sell blended fuel (blenders); and (3) Parties that produce petroleum fuel, purchase renewable fuel, and sell blended fuel (integrated refiners). A simplified version of the business activities each of these parties engage in, as well as the impact of the RFS program on their costs and revenue, is illustrated in Figure IV.D.2.b-2 below.

Merchant refiners produce, market, and sell petroleum fuel and buy the RINs they need for compliance with their RFS obligations; they do not purchase or blend renewable fuel. Integrated refiners also produce petroleum fuel, but unlike merchant refiners, they also purchase and blend renewable fuel to produce, and ultimately sell, blended fuel that contains some volume of renewable fuel. Integrated refiners generally do not purchase RINs, but instead purchase renewable fuel with attached RINs and acquire most of the RINs they need for compliance when they blend the renewable fuel.[141] Non-obligated blenders do not produce petroleum fuel

[140] A "blendstock" is defined as "any liquid compound or mixture of compounds (not including fuel or fuel additive) that is used or intended for use as a component of a fuel." 40 CFR 1090.80.
[141] Very few, if any, integrated refiners acquire all the RINs they need by blending renewable fuel. Petroleum fuel is subject to an RFS obligation for all four categories of renewable fuel, but it is generally only blended with one type of renewable fuel (i.e., ethanol in the case of gasoline and biodiesel or renewable diesel in the case of diesel fuel).

components, but instead purchase these products from merchant refiners. They then purchase renewable fuel with attached RINs that they use to produce, and ultimately sell, blended fuel (e.g., E10 and B5).[142] Because these parties do not have RFS obligations, they can also sell the RINs associated with the renewable fuel they blend.

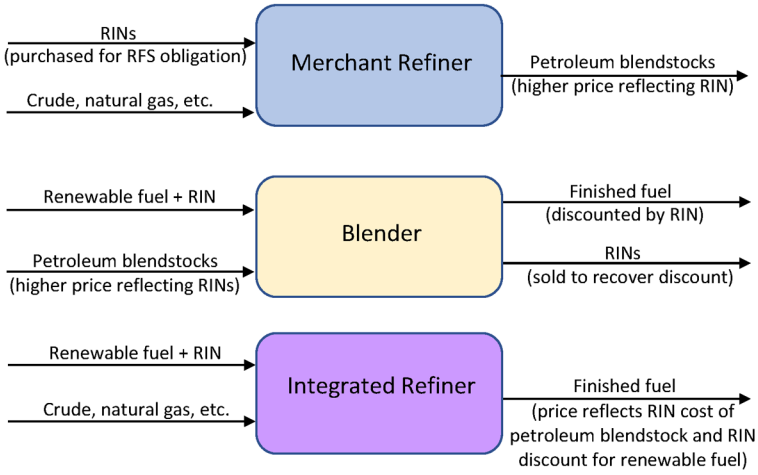
In practice there are few refineries that fall entirely into a single category, with most refiners having business interests that fall into at least two categories. Nevertheless, these distinctions help to clarify the context for RIN cost passthrough and the RIN discount in the price of blended fuel. While the RFS program results in new costs and revenue streams for various parties, we expect that, for each of these types of market participants (merchant refiners, integrated refiners, and blenders), these new costs are passed through in higher prices for refined products, while these new revenues from the sale of RINs are reflected in lower market prices for blended fuels, such that no refiner or blender realizes an advantage or disadvantage from the RFS program.[143]

Based on the 2020 RFS percentage standards, integrated refiners would generate a small amount of excess conventional biofuel (D6) RINs when blending ethanol as E10, but would need to purchase a small number of advanced biofuel (D5), biomass-based diesel (D4), and cellulosic biofuel (D3) RINs to meet the RFS obligation associated with the petroleum-based portion of the E10 blend. Similarly, integrated refiners that blend biodiesel as B5 would generate excess D4 RINs but would need to purchase D6 and D3 RINs to meet the RFS obligation associated with the petroleum-based portion of the B5 blend. In practice, nearly every gallon of blended fuel produced by an integrated refiner generates some quantity of excess RINs of one type and simultaneously incurs an obligation for other types of RINs.

[142] B5 refers to diesel fuel blended with 5% biodiesel.

[143] *See infra*, Section IV.D.2.c.

Figure IV.D.2.b-2: Simplified Illustration of Fuels Market Participants



The place in the fuel supply chain where we can see the *cost* of the RIN being passed through to consumers is in the price of the petroleum products. Since all parties have the same cost to acquire RINs (on a per gallon basis),[144] whether they blend renewable fuel or purchase separated RINs, one would expect the price for petroleum fuel subject to an RFS obligation (i.e., gasoline and diesel fuel) to increase when RIN prices increase and to decrease when RIN prices decrease. Just as the prices of gasoline and diesel fuel increase if fuel taxes increase,[145] they also increase when RIN prices increase. Merchant refiners fully recover the cost of their RFS obligations when the difference between the market price of gasoline and diesel fuel and the market price for these fuel in the absence of the RFS obligation is equal to the cost of purchasing the RINs to satisfy the RFS obligation. Equations showing the expected RIN price impacts on the prices of gasoline and diesel fuel, assuming RIN costs are fully passed through, are shown below.

[144] *See infra*, Section IV.D.2.c.
[145] EIA, *Gasoline explained: Factors affecting gasoline prices*, March 2, 2021, https://www.eia.gov/energyexplained/gasoline/factors-affecting-gasoline-prices.php.

Equation 1: Expected Impact on Gasoline (E0) Prices Assuming Full RIN Cost Passthrough

Gasoline Price = Gasoline Price with no RFS Obligation + RIN Costs

Equation 2: Expected Impact on Diesel Fuel (B0) Prices Assuming Full RIN Cost Passthrough

Diesel Fuel Price = Diesel Fuel Price with no RFS Obligation + RIN Costs

EPA once again examined these economic principles by looking at available market data, including more recent market data.[146] The data EPA examined show that the market prices for gasoline and diesel fuel operate as shown in Equations 1 and 2, supporting EPA's findings that all obligated parties recover the cost of their RFS obligations in the sale prices for the gasoline and diesel fuel they produce.[147] The ability for an obligated party to recover its RIN costs is not dependent on the obligated party's ability to set the price for these fuels in the markets where they are sold. Rather, because all obligated parties face the same RIN costs per gallon of gasoline and diesel fuel produced nationwide,[148] the market prices for these fuels rise and fall with changes in RIN prices in all markets by the same amount on any given day (after accounting for other factors that impact the prices of these fuels), such that all parties that sell gasoline and diesel fuel recover their RIN costs.[149]

The place in the fuel supply chain where we see the RIN discount is the point at which renewable fuel is blended with gasoline or diesel fuel and sold to fuel retailers. Parties that blend renewable fuel with gasoline or diesel fuel to produce transportation fuel must discount the price of the blended fuel by the price of the associated RIN.[150] These parties can then separate any RINs that are attached to the renewable fuel and either use these RINs to demonstrate compliance with their RFS obligations (if they are an obligated party) or sell these RINs to other parties. In either case, the point at which they acquired the RIN at the market price, or, rather, incurred a market rate cost for the RIN, is the point when they had to discount the blended fuel by the price of the RIN.

The sale of a RIN by a party that blends renewable fuel and separates the RIN creates a separate revenue stream in addition to the revenue from the sale of the blended fuel itself. Competitive forces require that blenders price their blended fuel based on the *net* price of renewable fuel, or the price of the renewable fuel less the price of the RIN associated with the fuel (e.g., net ethanol price = ethanol price – D6 RIN price; net biodiesel price = biodiesel – 1.5*D4 RIN price[151]). Any party that attempts to retain the revenue from the RIN sales, rather than passing it on to consumers via the RIN discount, is unable to offer blended fuel at a

[146] EPA's analysis of the market data to determine the degree to which RIN costs are passed through to consumers through higher prices for gasoline and diesel fuel is provided in Section IV.D.2.d.i.
[147] *See infra*, Figures IV.D.2.d.i.1 through 4, where EPA compared the price difference between a fuel subject to an RFS obligation to a very similar fuel not subject to an RFS obligation and the RIN cost per gallon of diesel fuel.
[148] *See infra* Section IV.D.2.d.ii.
[149] *See infra* Section IV.D.2.d.i.
[150] Another way to think about the RIN discount is that, to remain competitive, parties that blend renewable fuel must base the final price for the blended fuel on the net price of the renewable fuel (after accounting for the sale of the RIN) rather than on the price they paid for the renewable fuel with an attached RIN.
[151] Each gallon of biodiesel generates 1.5 RINs.

competitive price. If the market price for blended fuel is equal to the prices of the fuels used to create the blended fuel (e.g., 0.9 gallons of gasoline blendstock and 0.1 gallons of ethanol in the case of E10) without discounting the price for the renewable fuel by the price of the RIN, the RIN sales would result in profits for the blender. In the competitive fuels market, however, blenders are forced to reduce the price of the blended fuel to be competitive, consistent with the RIN discount phenomenon. If they do not, their competitors will give up the revenue from the sale of RINs to gain a greater market share. These competitive forces require that blenders use the revenue from the RIN sales to effectively subsidize the price of the blended fuel they sell.

This market phenomenon has been relatively obvious to program participants looking at the market for biodiesel blends where it was understood from the start of the RFS2 program that a higher D4 RIN price was necessary to reduce the effective market price of biodiesel to make it equivalent to petroleum diesel fuel. Integrated refiners and non-obligated blenders pay the higher cost for renewable fuel through their purchase and blending. Merchant refiners pay the non-obligated blenders the incremental cost of the renewable fuel for doing the blending of renewable fuel on their behalf when they purchase the separated RINs. As an illustrative example, if petroleum diesel fuel is selling at $3.00 per gallon, and it costs $4.50 per gallon to produce biodiesel and generate 1.5 D4 RINs, the price of a D4 RIN would need to be $1.00 for biodiesel to compete with petroleum diesel fuel so that the revenue from the sale of the 1.5 D4 RINs for $1.50 would lower the effective cost of the biodiesel to match the cost of the petroleum diesel fuel.[152] Any blender attempting to retain the revenue from the sale of the D4 RINs (rather than using it to discount the price of the blended fuel) could not offer a competitively priced blended fuel, since any biodiesel the blender used in its product would increase the cost of the fuel blend.

As described in greater detail below both in terms of economic principles and the recent data EPA received from small refineries, this market dynamic was previously not well understood when applied to the blending of ethanol to make E10. From the start of the RFS program until recently, there was no need to discount ethanol to create parity with gasoline blendstocks because ethanol has been relatively inexpensive and highly valued as an octane improver when blended to produce E10. As a result, both in the period prior to the RFS program and for the early parts of the RFS program, the market price for E10 was simply the weighted price for gasoline blendstock and ethanol. When D6 RIN prices increased, it was not obvious to many program participants how these high RIN prices impacted E10 prices, which many program participants simply assumed should continue to reflect the weighted costs of gasoline blendstock and ethanol. In fact, what has happened is that the high RIN prices have increased the production cost of gasoline blendstock (i.e., the RIN cost passthrough described in the preceding section) while simultaneously lowering the net cost of ethanol in almost equal proportion (the RIN discount), resulting in little change in the actual cost of E10 to consumers. While this competitive market response has meant little change in E10 prices due to the RFS program, it has created confusion among market participants who perceive that D6 RINs are "free" to parties that blend E10 while obligated parties that must buy the D6 RINs at market prices bear a very high cost. Instead, as we will show here based both on economic theory and the new small refinery data submissions, all sellers of E10 discount the price of E10 by the *price* of the D6

[152] In this example we are ignoring the impact of the federal biodiesel tax credit for simplicity. If we included the impact of the tax credit, it would reduce the RIN price needed to bring the net or effective price of biodiesel to parity with diesel fuel.

RIN, meaning fuel blenders pay for the RIN through this discounted E10 price at the same cost as if they purchased the RIN on the open market. As a result, parties that acquire RINs through fuel blending and parties that acquire RINs from the open market incur the same cost to acquire RINs.

Equations showing a generalized fuel blending example, and an example specific to E10, are provided below. These equations and the discussion that follows describe what one would expect if RIN prices are fully passed through to consumers. The subsequent sections examine market data to test these equations and determine the degree to which RIN prices are passed through to consumers.

Equation 3: Generalized Fuel Blending Example Assuming Full RIN Discount

Blended Fuel Price = PFP * PF% + (RFP – RIN Value) * RF%

Where: PFP = Petroleum Fuel Price

PF% = Petroleum Fuel Percentage in the fuel blend

RFP = Renewable Fuel Price

RIN Value = RIN Price * Equivalence Value[153]

RF% = Renewable Fuel Percentage in the fuel blend

Equation 4: Fuel Blending Example for E10 Assuming Full RIN Discount

E10 Price = Gasoline Blendstock Price * 90% + (Ethanol Price – D6 RIN Price) * 10%

EPA's analysis of the market data confirms these economic principles that the RIN value is passed through to consumers in the price of blended fuel.[154] The analysis—comparing the market prices for petroleum fuel, ethanol, RINs, and E10—shows that the market prices for blended fuel operate as shown in Equations 3 and 4, supporting EPA's findings that blenders are passing on the value of the RIN to consumers.[155] Importantly, this means that, although blenders do not purchase RINs directly, there is still a cost for blenders to acquire RINs. This cost is realized when blenders discount the price for the finished blended fuel, pricing it based on the net price of the renewable fuel, after accounting for the sale of any RINs attached to the renewable fuel. The data EPA analyzed support our finding that the RIN value is fully passed through from blenders to consumers, as described in Equations 3 and 4. Because the market is competitive, a blender cannot attempt to sell RINs at higher prices, consumers would merely go

[153] The equivalence value is an RFS regulatory term that relates the number of RINs generated per gallon of renewable fuel produced. Ethanol has an equivalence value of 1.0. Other renewable fuels have equivalence values that are determined by their energy content relative to ethanol. For example, biodiesel has an equivalence value of 1.5 RINs per gallon of biodiesel reflecting that biodiesel has approximately 150% the energy content of ethanol.
[154] *See infra*, Section IV.D.2.d.
[155] *See infra*, Section IV.D.2.d.ii.

to a competitor selling at the market price. Thus, the cost of acquiring a RIN by blending renewable fuel and the cost of purchasing a separated RIN are equal as would be expected from the design of the RFS program and RIN system.

c. Impacts on Different Market Participants

Before turning to the data that support EPA's proposed conclusion that RIN cost passthrough and the RIN discount are reflected in the prices of refined products and blended fuel, respectively, we first provide an illustrative example to examine the implications of RIN cost passthrough and the RIN discount on the three types of market participants described above: a merchant refiner, an integrated refiner, and a non-obligated blender. We present examples for producing both E10 and B5, two common fuel blends present in many fuels markets. Each of these parties produces, purchases, and sells different products within the E10 and B5 markets, but, as this example demonstrates, no party has a structural advantage or disadvantage since both the RIN cost and the RIN discount are passed through to consumers.

As previously discussed briefly, in reality very few parties fit entirely within only one of these three categories. Most refiners, both small and large, sell some volume of petroleum fuel (acting as merchant refiners) and blend some of their petroleum fuel with renewable fuel (acting as integrated refiners). Some also purchase gasoline or diesel fuel from other parties and blend it with ethanol to sell as E10 (acting as non-obligated blenders). Further, some refiners are also renewable fuel producers that produce the renewable fuel they blend rather than purchasing it from other parties and sell excess renewable fuel to others. Therefore, to better understand how various parties are affected by the RFS program and RIN prices, it is better to consider the role the party is playing in the fuels market (producing gasoline or diesel fuel, blending renewable fuel, etc.) than the predominant role of the company.

To illustrate the impact of the RFS program and RIN prices on parties acting in each of these roles, EPA evaluated scenarios with fuel prices, RIN prices, and RVOs as they existed on December 30, 2020. EPA also evaluated an alternative scenario where there was no RFS obligation. The fuel and RIN prices used in these scenarios, as well as the sources of these prices, are shown in Table IV.D.2.c-1 for the E10 example and Table IV.D.2.c-3 for the B5 example. The costs, revenue, and profit/loss for each party, both with and without the RFS program, are shown in Table IV.D.2.c-2 for E10 and Table IV.D.2.c-4 for B5.

The 2011 DOE Study included a very similar hypothetical value breakdown for various types of refiners in Appendix B of that study.[156] At the time DOE projected that *if* integrated refiners did not have to discount the E10 that they sell, then they could acquire RINs through blending at little or no cost. In this hypothetical scenario, integrated refiners that acquired RINs at little or no cost through blending renewable fuel would have a significant advantage relative to merchant refiners that purchased RINs at a higher market price. However, as the examples below illustrate, integrated refiners must compete with non-obligated blenders in the blended fuels market. To offer competitively priced blended fuel, integrated refiners (like blenders) must discount the price of the blended fuel by the price of the RIN attached to the renewable fuel contained in the blended fuel. Market data reviewed by EPA confirms that the price of blended

[156] *See supra*, Section II.D.

fuel reflects the RIN discount.[157] Thus, contrary to the hypothetical example in the 2011 DOE Study,[158] we find that all obligated parties have the same cost to acquire RINs, whether they acquire RINs through blending renewable fuel or purchasing separated RINs.

Table IV.D.2.c-1: BOB[159], Ethanol, E10, and RIN Prices on December 30, 2020

Product	Price	Data Source
BOB Cost of Production	$1.34	Assumed to be equal to the BOB Market Price without RIN Cost
BOB Market Price without RIN Cost	$1.34	Calculated (BOB Market Price with RIN Cost less RIN Cost)
BOB Market Price with RIN Cost	$1.44	EIA
Ethanol Market Price	$1.50	OPIS
E10 Market Price with the RFS Program	$1.37	Calculated using BOB Market Price with RIN Cost, Ethanol Market Price, and D6 RIN Price
E10 Market Price without the RFS Program	$1.36	Calculated using BOB Market Price without RIN Cost and Ethanol Market Price
D6 RIN Price	$0.77	OPIS
RIN Cost per Gallon of BOB	$0.10	Calculated from 2020 RVO and OPIS RIN Prices
D6 RIN Cost per Gallon of E10	$0.06	Calculated from 2020 RVO and OPIS RIN Prices
D3, D4, and D5 RIN cost per gallon of E10	$0.03	Calculated from 2020 RVO and OPIS RIN Prices

[157] *See infra*, Section IV.D.2.d.ii.

[158] DOE's example in Appendix B of the 2011 DOE Study included a comparison of Company A that blends all its production with ethanol and does not need to purchase ethanol RINs, with Company B that does not do any blending and must purchase RINs to meet its entire RFS obligation, and Company C that blends in excess of its obligation and has RINs to sell into the market. In DOE's hypothetical case, Company A acquired RINs at no cost (n/a in the estimate) while Company B faced a 15 cent per RIN cost to purchase RINs. 2011 DOE Study at B-4.

[159] BOB is an intermediate petroleum product that is used in making finished gasoline and is generally blended with ethanol to make E10. BOB represents the petroleum-based portion of blended gasoline that has a RIN obligation attached to it. Therefore, BOB can be used to show the price impacts of the RIN market on the petroleum component of blended fuel.

Table IV.D.2.c-2: Illustrative Costs, Revenue, and Profit for E10 Production

Line		Merchant Refiner		Integrated Refiner		Non-Obligated Blender	
		With RFS	No RFS	With RFS	No RFS	With RFS	No RFS
2-1	0.9*BOB Cost of Production	$(1.21)	$(1.21)	$(1.21)	$(1.21)	-	-
2-2	0.9*RIN Cost	$(0.09)	-	$(0.09)	-	-	-
2-3	0.9*BOB Market Price	$1.30	$1.21	-	-	$(1.30)	$(1.21)
2-4	0.1*Ethanol Market Price (with RIN)	-	-	$(0.15)	$(0.15)	$(0.15)	$(0.15)
2-5	0.1*Net Ethanol Market Price (no RIN)	-	-	$(0.07)	$(0.15)	$(0.07)	$(0.15)
2-6	E10 Market Price (per Gallon)	-	-	$1.37	$1.36	$1.37	$1.36
2-7	D6 RIN Purchases	$(0.06)	-	-	-	-	-
2-8	D3, D4, and D5 RIN Purchases	$(0.03)	-	$(0.03)	-	-	-
2-9	D6 RIN Sales	-	-	$0.02	-	$0.08	-
2-10	Profit/Loss per Gallon E10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table IV.D.2.c-3: Diesel Fuel, Biodiesel, B5 and RIN Prices on December 30, 2020

Product	Price	Data Source
ULSD Cost of Production	$1.38	Assumed to be equal to the ULSD Market Price without RIN Cost
ULSD Market Price without RIN Cost	$1.38	Calculated (ULSD Market Price with RIN Cost less RIN Cost)
ULSD Market Price with RIN Cost	$1.48	EIA
Biodiesel Market Price	$3.66	OPIS
Biodiesel Tax Credit	$1.00	N/A
B5 Market Price with the RFS Program	$1.46	Calculated using ULSD Market Price with RIN Cost, Biodiesel Market Price, and D4 RIN Price, and Tax Credit Price
B5 Market Price without the RFS Program	$1.44	Calculated using ULSD Market Price without RIN Cost, Biodiesel Market Price, and Tax Credit Price
D4 RIN Price	$1.00	OPIS
RIN Cost per Gallon of ULSD	$0.10	Calculated from 2020 RVO and OPIS RIN Prices
D4 RIN Cost per Gallon of B5	$0.02	Calculated from 2020 RVO and OPIS RIN Prices
D3, D5, and D6 RIN cost per gallon of B5	$0.07	Calculated from 2020 RVO and OPIS RIN Prices

Table IV.D.2.c-4: Illustrative Costs, Revenue, and Profit for B5 Production

Line		Merchant Refiner		Integrated Refiner		Non-Obligated Blender	
		With RFS	No RFS	With RFS	No RFS	With RFS	No RFS
4-1	0.95*ULSD Cost of Production	$(1.31)	$(1.31)	$(1.31)	$(1.31)	-	-
4-2	0.95*RIN Cost	$(0.09)	-	$(0.09)	-	-	-
4-3	0.95*ULSD Market Price	$1.41	$1.31	-	-	$(1.41)	$(1.31)
4-4	0.05*Biodiesel Market Price (with RIN)	-	-	$(0.18)	$(0.18)	$(0.18)	$(0.18)
4-5	0.05*Tax Credit	-	-	$0.05	$0.05	$0.05	$0.05
4-6	0.95*Net Biodiesel Price			$(0.06)	$(0.13)	$(0.06)	$(0.13)
4-7	B5 Market Price (per Gallon)	-	-	$1.46	$1.44	$1.46	$1.44
4-8	D4 RIN Purchases	$(0.02)	-	-	-	-	-
4-9	D3, D5, and D6 RIN Purchases	$(0.07)	-	$(0.07)	-	-	-
4-10	D4 RIN Sales	-	-	$0.05	-	$0.07	-
4-11	Profit/Loss per Gallon E10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

The illustrative examples presented in Tables IV.D.2.c-2 and 4 demonstrate several important points about the impact of the RFS program and RIN prices on merchant refiners, integrated refiners, and non-obligated blenders. First, since the RIN cost (lines 2-2 and 4-2) and the RIN discount (blended fuel prices based on net renewable fuel prices; lines 2-6 and 4-7) are fully passed through to consumers, no party benefits or is harmed by the RFS program, either in absolute terms or relative to their competitors.[160] This can be seen in lines 2-10 and 4-11. In each of the examples, the revenues and costs of various products change as a result of the RFS, but the profit/loss and, thus, the potential harm for each of these three parties is identical with and without the RFS.

Second, a merchant refiner's ability to recover its RIN costs in the price of the fuel it produces does not depend on its ability to be a "price setter" or to receive a price for its fuel that is above the market price. Instead, the market price for fuel increases to account for the RIN cost associated with producing the fuel (RIN cost passthrough). Whether and the degree to which a refiner is a "price setter" or "price taker" is not influenced by the RFS program. Rather, the RFS program merely shifts upward the price at which this competitive dynamic is at play. This price impact can be seen by comparing the market prices for gasoline and diesel fuel (lines 2-2 and 4-2, respectively) with and without the RFS program. Merchant refiners automatically receive a price for their fuel that reflects the cost increase due to the RFS program (i.e., the cost of the RIN) when they sell the fuel at the market price.

Third, if a refiner (merchant or integrated) has a higher cost of production than the market price without the RFS program, it will lose money for each gallon of fuel it produces. This is true both in the absence of the RFS program and with the RFS program. Any party that has a higher cost of production than the market price for the goods it produces will lose money when selling those goods. However, the higher market prices for fuels can obscure these underlying fundamentals. In the example presented in Table IV.D.2.c-1, if a merchant refiner's cost to produce 0.9 gallons of gasoline is $1.30, it may appear that the refiner would break even by selling gasoline at the market price (line 2-3) but for the RIN purchases (lines 2-7 and 2-8). Several petitioners have made this very claim, that their refineries would be profitable if they did not have to purchase RINs but are not profitable after accounting for their RIN costs. However, such claims ignore the fact that in the absence of the RFS program, the market price for 0.9 gallons of gasoline (line 2-3) would fall to $1.21, resulting in a $0.09 loss. If a refiner's cost of production exceeds the marginal supply price for its market, the refiner will lose money for every gallon of fuel it produces due to its high cost of production, regardless of the presence or absence of the RFS program. As demonstrated by the identical results for all parties in Tables IV.D.2.c-2 and 4, the RIN compliance costs associated with the RFS program do not have a differential impact on the refiner's situation.

Fourth, while integrated refiners that do their own blending have the same cost to acquire RINs as merchant refiners, they spend less on separated RIN purchases when they produce E10 or B5 (lines 2-7 and 4-8, respectively). Integrated refiners are acting both as merchant refiners (producing fuel that carries an RFS obligation) and as blenders (blending renewable fuel and separating the attached RINs) at the same time. However, rather than purchasing all the RINs

[160] Throughout Section IV.D.2.c, references to "lines" are to Table IV.D.2.c-2 (lines beginning with 2-) and Table IV.D.2.c-4 (lines beginning with 4-).

they need from other parties or selling all the RINs they acquire through blending renewable fuel, integrated refiners acquire many of the RINs they need for compliance from blending renewable fuel rather than purchasing these RINs. The transfer of RINs from the blending operation of an integrated refiner to the refining operation is an internal transfer, rather than an external purchase or sale that is easier to see in financial reports. While it may appear that integrated refiners are at an advantage relative to merchant refiners under the RFS program because they purchase fewer RINs per gallon of fuel produced (see lines 2-7 and 4-8) than merchant refiners, they also sell fewer RINs than non-obligated blenders (lines 2-9 and 4-10). These two impacts—the higher RIN purchases relative to merchant refiners and the lower RIN sales relative to non-obligated blenders—offset each other such that integrated refiners neither benefit from the RFS program, nor are at a disadvantage relative to merchant refiners or non-obligated blenders under the RFS program.

Another way to understand the impact of the RFS program on integrated refiners is to consider the opportunity cost to these parties of selling blended fuel rather than petroleum fuel. Integrated refiners are competing with non-obligated blenders when they sell blended fuel (lines 2-6 and 4-7). These blenders must discount the price of the blended fuel they sell because of the revenue they realize when they sell the RINs associated with the renewable fuel (lines 2-9 and 4-10). Integrated refiners generally keep the RINs they acquire when they blend renewable fuel, so they do not have this revenue source to reduce the price of their blended fuel to compete with blenders. Instead of revenue from RIN sales, integrated refiners can use their own production of petroleum fuel, which has a lower cost of production than the market price for the fuel (lines 2-1 and 2-3 and lines 4-1 and 4-3), to produce blended fuel. Access to these lower-cost fuels allows integrated refiners the ability to offer blended fuel at the same price as non-obligated blenders—which use the revenue from RIN sales to discount the price of their blended fuel—despite the fact that they use the RINs they acquire through blending for RFS compliance, rather than selling them to other parties. In doing so they give up the opportunity to sell their petroleum fuel at the higher market rate, which reflects the RIN cost (lines 2-2 and 4-2).

Fifth, the fact that refiners are able to recover the cost of the RINs they need for compliance and that blenders pass through the RIN discount to consumers does not mean that the RFS program has no impact on fuel prices. The RFS program functions as a cross-subsidy, where RINs increase the market price of petroleum fuel (lines 2-3 and 4-3) and decrease the net price of renewable fuel (lines 2-5 and 4-6). This means that the RFS program reduces the market price for fuel with higher renewable fuel content (e.g., E85 or B20) and increases the market price for fuel with little or no renewable content (e.g., E0 or B0). Notably, the RIN cost and the RIN discount are not the same for all blended fuels. RIN costs (lines 2-2 and 4-2) are proportional to the quantity of petroleum fuel in the blended fuel while the RIN value used to discount the price of the renewable fuel is proportional to the quantity and type (D6 ethanol, D4 biodiesel, etc.) of renewable fuel in the blended fuel. In the two examples in Tables IV.D.2.c-2 and 4, the RIN cost and the RIN discount for E10 and B5 are very similar and as a result the prices for E10 and B5 with and without the RFS program (lines 2-6 and 4-7, respectively) are very similar. This is not the case for fuels with significantly higher or lower proportions of renewable fuel.

Finally, while non-obligated blenders realize revenue from RIN sales (lines 2-9 and 4-10), this revenue is not a windfall profit. Instead, RIN revenues result in lower net prices for renewable fuels (lines 2-5 and 4-6). The prices of the blended fuel (lines 2-6 and 4-7) then reflect the lower net cost for the renewable fuel under the RFS program. For fuels such as E10 and B5, when the RIN value of the renewable fuel in the blend is approximately equal to the RIN cost associated with the petroleum fuel in the blend, it can be difficult to see the impact of the RFS program in the blended fuel price. For fuels with significantly higher or lower renewable fuel content, the impact is more pronounced. RINs decrease the price for fuel with a high renewable content (e.g., B20 or E85), while RINs increase the price for fuel with little or no renewable content (e.g., E0 or B0). This is the mechanism by which the RFS program was intended to increase the production and use of renewable fuel in the United States.

In the calculations in Tables IV.D.2.c-2 and 4, we have made several simplifying assumptions. First, we have assumed that the fuel cost of production for both the merchant refiner and the integrated refiner (lines 2-1 and 4-1) is equal to the market price for the fuel without the RFS program. In practice, the marginal cost to supply fuel to any given market sets the market price. Each refiner's refining margin would, therefore, be determined by its actual fuel cost of production relative to the market price for the fuel. RIN costs increase the market price for the fuel by an amount equal to the RIN cost, since all parties have the same RIN costs. However, since the market price for fuel reflects the RIN cost, the merchant refiner's profit/loss is determined by its cost of production relative to the marginal cost of production for its market, with or without the RFS program. Said another way, different refineries in a market will have differing profit margins for the fuel they produce. But since the RFS compliance costs (i.e., RINs) apply equally to every gallon of fuel produced, these costs directly impact all gasoline and diesel fuel volumes equally, raising the marginal supply price for these products. Thus, RIN prices increase a refinery's costs and the market price for their production, but the difference between the refining margins for the different refineries will remain the same with and without the RFS program.

Similarly, in this example we have assumed no blending margin or cost for blending beyond the purchase of petroleum fuel and renewable fuel. This is a simplification that does not reflect the fact that, in addition to the cost of purchasing fuel, blenders also have operating costs and fixed costs. These costs include, among others, labor costs, maintenance costs, and capital recovery costs. Blenders must earn a margin when they sell blended fuel to cover these fixed and operating costs, and the market price for blended fuel reflects the fixed and operating costs of the marginal fuel blender. However, not all blenders will have the same fixed and operating costs. Much like the previous example, we would expect a blender's (or integrated refiner's) profit/loss for blending renewable fuel to be equal to its fixed and operating costs relative to the fixed and operating costs of the marginal blender. Blenders and integrated refiners with relatively low blending costs are expected to earn greater profits through blending, while blenders and integrated refiners with relatively high blending costs are expected to earn relatively lower profits (or losses) through blending. This is true independent of the RFS program, as RIN costs/revenues are neutral. Notably, the design of the RFS program enables the market to function efficiently by allowing those refiners that have relatively high fixed and operating costs of blending renewable fuel to purchase RINs from blenders that have lower fixed and operating costs of blending renewable fuel. We acknowledge this simplification and note that our decision

to exclude a blending margin from the examples presented in Tables IV.D.2.c-2 and 4 does not affect the conclusions highlighted above.

d. EPA Evaluation of Available Market Data

EPA analyzed the available market data to verify the economic principles at work and to verify that the RIN cost and the RIN discount are being reflected in the retail price of blended fuel.[161] These analyses, including analyses conducted for previous assessments of the passthrough of both the RIN cost and the RIN discount, as well as new analyses using more recent data, are presented in this section. These analyses confirm that both the *cost* of the RINs—which is reflected in the prices for fuel and blendstocks—and the *discount* of the RINs are passed through to consumers in the marketplace in the price they pay for blended fuel.

i. Assessment of Data on RIN Cost Passthrough

EPA first assessed available data to determine whether refiners are able to recover the *cost* of the RINs they need to demonstrate compliance with their RFS obligations through higher prices for the petroleum fuel they produce, as described in Equations 1 and 2. This analysis is complicated by the fact that the terms in Equations 1 and 2 for the gasoline price with no RFS obligation and the diesel fuel price with no RFS obligation cannot be found in market data from the United States, as the reported data will always reflect the cost of the RFS obligation. As described below, however, there are market data on the prices of fuels that are very similar (and in some cases identical) where one fuel has an RFS obligation and the other does not.

In 2015, EPA identified prices for near-identical fuels (in terms of technical fuel specifications, and, therefore, presumably cost of production) except for the fact that one fuel was subject to an RFS obligation while the other was not.[162] We then used the price of the non-obligated fuel to approximate what the cost of the obligated fuel would be in the absence of the RFS obligation. We then compared the price difference between these two fuels, which represents the increase in the market price of the obligated fuel as a result of its RFS obligation, to the RIN cost for producing or importing a gallon of fuel subject to an RFS obligation. The strong correlations between the price differences for similar fuels with and without an RFS obligation and the RIN cost per gallon of obligated fuel led to the conclusion that the market prices for gasoline and diesel fuel are higher than they would otherwise be in the absence of the RFS program. Further, the observed price difference was equal to the cost of purchasing the RINs needed to meet the compliance obligations for a gallon of gasoline or diesel fuel. We therefore concluded that all refiners recovered the full cost of the RINs they purchase through the prices of the fuel they sell.

EPA has since repeated the analytical techniques first developed in 2015 using more recent data from 2017–2020. Figure IV.D.2.d.i-1 shows the price difference in New York Harbor between ULSD, which is subject to an RFS obligation, and heating oil, which is essentially an identical product except that it is not subject to an RFS obligation. As expected, there is a very

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[161] *See supra*, Section IV.D.2.b.

[162] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA, May 14, 2015.

strong correlation between these data sets, as shown in Figure IV.D.2.d.i-2. The market price premium for ULSD over that for heating oil consistently matches the RIN cost (i.e., the cost of purchasing the RINs needed to meet the RFS obligation).

Similarly, Figure IV.D.2.d.i-3 shows the price difference in the Gulf Coast between ULSD, which is subject to an RFS obligation, and jet fuel, which is not. However, as shown in Figure IV.D.2.d.i-4, the correlation between the price difference of ULSD and jet fuel and the RIN cost is not as strong as the correlation between the price difference of ULSD and heating oil and the RIN cost. This is to be expected, as there are more significant product quality differences between ULSD and jet fuel such that they are not one-for-one replacements of each other, and they are used primarily in different markets with distinct supply/demand issues that would also contribute to differences in their market prices.[163] Thus, there is more noise in these data, but a general relationship between the price difference among these fuels and the RIN cost can be seen. Also apparent in Figure IV.D.2.d.i-3 is the impact of the COVID-19 pandemic. In late March 2020 air travel and demand for jet fuel decreased dramatically, resulting in an over-supply of jet fuel and a spike in the price premium for ULSD over jet fuel.[164] Over time, as demand for jet fuel gradually increased and refiners adjusted their production to better match fuel demand, the price difference between jet fuel and ULSD returned to match the RIN cost. Taken together, these more recent data confirm EPA's original conclusion that the market prices for gasoline and diesel fuel reflect the RIN cost, and, therefore, all refiners are able to recover their RIN costs through the sales prices of these fuels.

[163] Jet fuel generally contains more sulfur than ULSD. While the properties of jet fuel are closer to #1 diesel than to #2 diesel, EPA's public data does not contain prices for #1 diesel.
[164] EIA, *COVID-19's impact on commercial jet fuel demand has been significant and uneven*, Today in Energy (August 7, 2020), https://www.eia.gov/todayinenergy/detail.php?id=44676.

Figure IV.D.2.d.i-1: Price Difference Between ULSD and Heating Oil in New York Harbor and RIN Cost (2017-2020)[165]

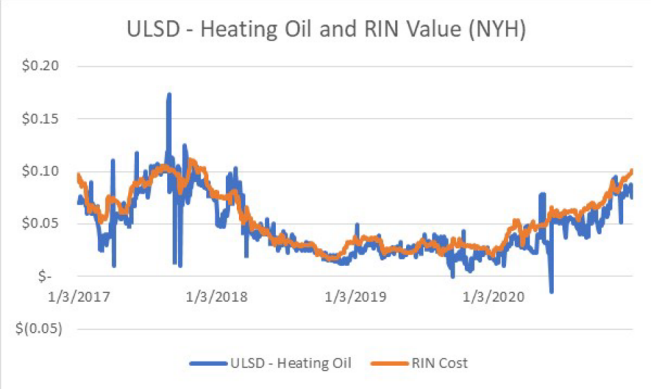


Figure IV.D.2.d.i-2: Correlation Between Price Difference of ULSD and Heating Oil and RIN Cost (2017-2020)



[165] Prices for ULSD and heating oil are reported by EIA and are available at: https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

Figure IV.D.2.d.i-3: Price Difference Between ULSD and Jet Fuel in the Gulf Coast and RIN Cost (2017-2020)[166]

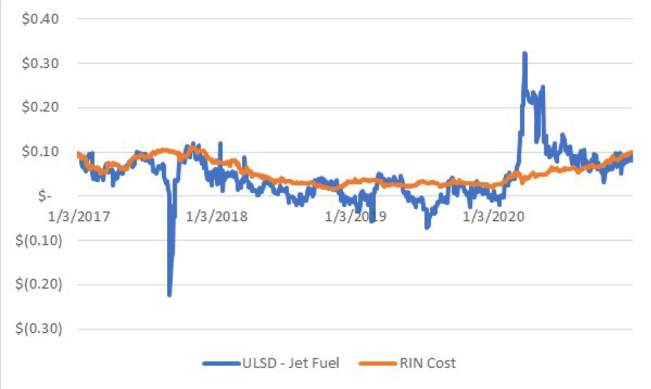


Figure IV.D.2.d.i-4: Correlation Between Price Difference of ULSD and Jet Fuel and RIN Cost (2017-2020)



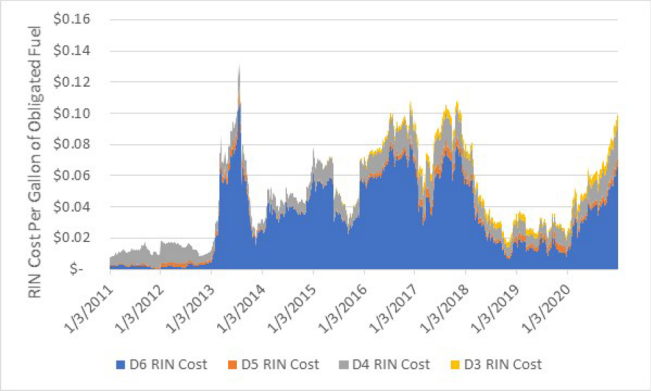
In their SRE petitions, several small refineries submitted examples of fuel pricing contracts in their local markets. Notably, many of these contracts indexed the sales price for fuel in the typically smaller markets into which the small refineries sell fuel to larger fuels markets, usually with the addition of transportation costs. The structure of these contracts supports EPA's

[166] Prices for ULSD and jet fuel are reported by EIA and are available at: https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

finding that the inclusion of the RIN cost in the price of obligated fuel is not unique to larger, coastal fuels markets, but is true across the United States. If the RIN cost is reflected in the sales price of fuel in New York Harbor and the Gulf Coast, it is certainly reflected in markets, including smaller markets, that *index* their pricing to these larger markets. Furthermore, because of the highly connected and competitive nature of fuels markets across the United States, one would expect every fuels market to reflect these same pricing dynamics. To date, no petitioning small refinery has provided EPA with data nor have we found other data that is in conflict with this expectation. In fact, small refineries that participate in both larger markets and smaller markets have consistently highlighted to EPA that they are in direct competition with larger and better resourced refineries regardless of their location. Even in cases where the small refineries themselves may not distribute fuel beyond a relatively small geographic area, the large integrated refiners with which they compete in those local markets do sell fuels into the larger distributed markets. It would not make economic sense for these large integrated refiners, which have access to larger fuels markets where market prices reflect the cost of RINs, to choose to sell into the smaller markets occupied by small refineries unless the market prices in those smaller markets also reflected the RIN cost.

Another important observation from these data is that neither the RIN cost nor the additional revenue a refiner receives for an obligated fuel compared to a non-obligated fuel (the premium for obligated fuel versus a similar non-obligated fuel) are static. There has been significant variation in these prices from 2017-2021, from approximately $0.10 per gallon in late 2017 and late 2020, to a low of approximately $0.03–0.04 per gallon throughout 2019. RIN prices have continued to increase in 2021, with prices for most RIN categories currently 50–100% greater than RIN prices at the end of 2020 (see Figure IV.D.2.d.i-5).

Figure IV.D.2.d.i-5: RIN Cost Per Gallon by RFS Category (2011-2020)



Obligated parties that choose to purchase the RINs they need for compliance on a ratable basis (i.e., purchase on a systematic, regular basis the number of RINs needed to satisfy their obligation for all the fuel sold each day) will recover the cost of the RINs they purchase in the

sales price of the petroleum fuel they sell. Conversely, obligated parties that choose to delay RIN purchases, or to purchase excess RINs in advance of producing or importing petroleum fuel, may recover more or less than the price they paid for RINs in the sales price of the petroleum fuel they sell, depending on whether the RIN price on the purchase date is higher or lower than the RIN price on the date the petroleum fuel is sold. For example, based on the data presented in Figures IV.D.2.d.i-1 and 3, an obligated party that sold fuel in July 2020 received approximately $0.06 per gallon more than it would have in the absence of the RFS program. If that obligated party delayed purchasing RINs until the end of 2020, the RIN cost would have been approximately $0.10 per gallon. Conversely, if the obligated party had purchased excess RINs in January 2020, the RIN cost would have been approximately $0.03 per gallon. Thus, the decision to delay RIN purchases until December 2020 would have cost an obligated party an additional $0.04 per gallon of fuel produced in July 2020; whereas purchasing excess RINs in January 2020 would have resulted in an additional $0.03 per gallon profit for every gallon of fuel produced in July 2020. By purchasing RINs ratably, all obligated parties have the ability to match their RIN costs with the price they receive when they sell their fuel (i.e., to pass through their RIN costs). Alternatively, refineries can try to time their purchases in the RIN market, which may result in greater or lesser RIN costs. EPA strongly disputes any notion that costs resulting from individual refinery's business decisions, including the choice to delay RIN procurement in hopes of receiving an SRE, or an attempt to time the transaction to profit from the fluctuation in the RIN market prices over time, represent DEH *caused* by the RFS program. Rather, individual business decisions made by an obligated party not to ratably accrue RINs as the obligation accrues, but instead to either purchase RINs in advance or delay RIN purchases until a later date, are speculation in the RIN market, a business activity not required to comply with the RFS program. Thus, these costs cannot be considered to represent DEH caused by compliance with the RFS program.

ii. Assessment of Data on the RIN Discount

To verify that fuel blenders are passing through the RIN discount to consumers through the price of blended fuel as described by Equations 3 and 4, EPA considered information from a variety of sources. We evaluated the issue by analyzing market pricing data for petroleum fuel, renewable fuel, RINs, and blended fuel (including data submitted by petitioners), statements from blenders in publicly available earnings reports, and fuel pricing contracts submitted by petitioners. Each of these data sources support EPA's finding that revenue from RIN sales does not represent a windfall profit for fuel blenders. Rather, they demonstrate that blenders pass through the full value of the RIN to consumers in discounts on the price of the blended fuel they sell and, therefore, do not retain any revenue from the sale of RINs.

There are a limited number of markets where prices for each of these fuels are reported, but all of those we have seen confirm our conclusions that fuel blenders are passing through the RIN discount to consumers through the price of blended fuel.[167] In 2015, EPA analyzed market data from Des Moines, Iowa and demonstrated that there was a very strong correlation between the difference in the posted price for E10 in Des Moines and the calculated E10 price based on

[167] This same point was raised in one small refinery's petition, along with data to illustrate it. The small refinery claimed its petition and all supporting information as confidential business information.

the component fuels (gasoline blendstock and ethanol), and the RIN price per gallon of E10.[168] These data indicated that fuel blenders are selling blended fuel based on the net price of the renewable fuel (after accounting for the sale of any associated RINs). This means that the price of the blended fuel was lower than the cost to purchase the components of the fuel blend (gasoline blendstock and ethanol with a RIN) and that revenue from RIN sales offset these costs. The result of this pricing behavior is that 100% of the revenue from RIN sales was passed on to consumers.

Two petitioning small refineries submitted data to EPA on fuel prices in their markets that enabled EPA to analyze current data in additional markets using a methodology similar to the analysis we conducted for Des Moines in 2015.[169] One small refinery used monthly gasoline and ethanol pricing data from a local terminal, along with RIN pricing data, to determine a monthly calculated E10 price from 2010 to the present using an equation nearly identical to Equation 2.[170] That petitioner then plotted these calculated E10 prices, which assume that 100% of the RIN value is passed through to consumers through lower prices for blended fuel, against the posted prices for E10 at that same terminal. The petitioner found an extremely strong correlation ($R^2 = 0.9976$) between the calculated E10 price (assuming 100% RIN passthrough) and the posted E10 price, demonstrating for this terminal that the RIN value has been fully passed through to consumers since 2010.[171]

Another petitioning small refinery's fuel pricing data allowed EPA to conduct a similar analysis for yet another market.[172] This small refinery provided daily pricing information for E10 from a local terminal, as well as daily pricing information for gasoline blendstock and ethanol from a nearby market along with the cost to transport these fuels to the refinery's local market. Daily prices were provided from January 1, 2019 through June 21, 2021. EPA used the data to calculate an E10 price using Equation 2 and compared these calculated E10 prices (assuming the E10 price was based on the net price of the ethanol, passing through 100% of the RIN in the discounted price of E10) to the posted E10 prices at the local terminal. As with the data provided by the other petitioning small refinery, we again find an extremely strong correlation ($R^2 = 0.9991$) between these two prices, further confirming our previous findings that the RIN price is fully passed through to consumers as a discount on the price of the renewable fuel when petroleum fuel and renewable fuel are blended and then sold.

Support for EPA's finding that the RIN discount is fully reflected in the price of blended fuels and is accordingly passed through to consumers by fuel blenders can also be found in

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[168] "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, US EPA, May 14, 2015.
[169] We do not present the data here because the petitioners have claimed it contains CBI.
[170] The only difference between Equation 2 and the equation used by the petitioner to determine the calculated E10 price was that the petitioner included an additional terminaling and throughput charge that applies regardless of the RFS program and is not relevant to this discussion.
[171] This petitioner acknowledged that the RIN was used to discount the price of blended fuel at their terminal. However, the petitioner further argued that the RIN cost could not be recovered in the cost of the gasoline and used to discount the price of the blended fuel. As discussed further in Section IV.D.2.c, both the economic principles and the market data demonstrate that this is incorrect. Refiners recover the cost of the RIN through the sales of their petroleum fuel and the RIN is used to discount the price of blended fuel.
[172] We do not present the data here because the petitioners have claimed it contains CBI.

public statements by the blenders themselves. Several parties directly involved in fuel blending supported EPA's findings in comments[173] on EPA's Point of Obligation denial.[174] More recently, R. Andrew Clyde, President, CEO & Director of Murphy USA, a large fuel blender and retailer, was asked if the recent high RIN prices positively affected Murphy USA's margins in a Q1 2021 earnings report. He responded:

> The reality is RINs and RIN prices are immaterial to our business. Historically, and you can look back over the last 3 years annual results, we've made $0.02 to $0.03 per gallon on product supply and wholesale net of RINs. And so during the quarter on the average, we generated about the equivalent of $0.07 a gallon per RIN, but net of the negative spot to rack margins of $0.04, we netted a little bit over $0.03…If RINs are high, the refiner gate price is high and like it was in this quarter, our refinery gate spot to rack margin is negative…So RIN prices don't matter. The product supply margin plus the RINs is going to be about $0.02 to $0.03.[175]

Mr. Clyde describes a market dynamic wherein blenders experience negative blending margins (due to competitive market forces requiring that the RIN price be reflected in the market price of blended fuel) that are offset by revenue from selling RINs, with total margins (including fuel blending and RIN sales) relatively stable and independent of RIN prices.[176] These dynamics are exactly what one would expect to see if blenders are passing through 100% of the RIN price as a discount to consumers in the price of blended fuel.[177]

Several petitioning small refineries also provided EPA with examples of contracts for fuel sales.[178] While there were some differences among these contracts, they generally showed that the sales price for blended E10 was discounted by the value of the RIN associated with the ethanol blended into the fuel blend. Many of the pricing formulas shown in these contracts looked very similar to Equation 4, with some referencing petroleum fuel and/or ethanol prices in nearby markets and including transportation costs. In some cases, the contracts stipulated that the purchase price would be the lower of the calculated price based on the prices of the petroleum fuel and the net price of ethanol (thus passing through 100% of the RIN price to consumers) or the posted price of E10 at the local terminal, whichever was lower. These contracts provide yet more evidence that the price of the RIN is reflected in the sales price for blended fuel, and further that the passthrough of the RIN price to consumers is not limited to any particular U.S. market.

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[173] *See* Letter from RaceTrac to Administrator McCarthy, August 17, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0014; Letter from QuikTrip to Administrator McCarthy, August 17, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0013; Presentation from Murphy USA to EPA, August 16, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0028.

[174] 81 FR 83776 (November 22, 2016) and 82 FR 56779 (November 30, 2017).

[175] Murphy USA Inc. FQ1 2021 Earnings Call Transcripts (April 29, 2021).

[176] Petitioners' claims of "RIN theft" and windfall profits from RIN sales by Murphy USA and other blenders are further addressed in Section IV.D.2.a.

[177] *See supra*, Section IV.D.2.b.

[178] We do not present the contract data here because the petitioners have claimed it contains CBI.

3. EPA Responses to Small Refinery Arguments for Exemption

The petitioning small refineries raise many similar arguments in their petitions and in supplemental information they submitted to support receiving an exemption from their RFS obligations. Because these arguments are repeated by most, if not all, SRE petitioners, EPA is addressing them in this section at a level of generality needed to maintain the claims of CBI asserted by the small refineries in their respective petitions. The refineries generally argue eight overarching themes in their petitions and supplemental information. However, EPA recognizes that this list is not comprehensive. Some refineries provided information and perspective that we do not address in this proposal, primarily because we are still seeking the underlying data or additional explanation to understand and respond to the individual or market-specific circumstances the petitioners describe.

The general themes small refineries have articulated are: (a) They face unique challenges that prevent them from achieving RIN cost passthrough and that EPA must consider their specific circumstances; (b) EPA's Point of Obligation denial did not address their situations and does not apply to them; (c) The Point of Obligation denial is out of date and inapplicable; (d) The revenue from RIN sales allows large retailers to undercut small refineries; (e) Large integrated refiners set prices in fuels markets, undercutting small refineries on price because of their market position and because large integrated refiners have lower or no RIN costs; (f) EPA is incorrect about parity between the cost of obtaining a RIN through blending and the cost of buying a RIN on the market; (g) Single site refineries are disadvantaged relative to large integrated refiners because they only have access to a limited market; and (h) Small refineries that produce primarily diesel fuel are at a disadvantage since they cannot blend as much renewable fuel into their product as can refineries that produce gasoline.

EPA evaluates and responds to each of these general themes below.

a. Small refineries face unique challenges that prevent them from passing through their RIN costs. EPA must consider each small refinery's specific situation.

Small refineries assert that "EPA must do more than cite to the Burkholder Report's conclusion 'that the refining industry *as a whole* is not burdened by rising RIN prices because refineries may pass that cost to purchasers of the blended fuel.' *Ergon-W. Va., Inc. v. EPA*, 896 F.3d 600, 613 (4th Cir. 2018) (emphasis added)."[179] The small refineries further assert that EPA has, in the past, ignored information specific to individual refineries that demonstrates that they cannot pass through the prices they pay for RINs due to unique operational or local market circumstances.

The small refineries misstate the holding from *EWV-I* and completely ignore the follow-up to that case, *EWV-II*. The court in *EWV-I* held that EPA had acted arbitrarily and capriciously when it "failed to squarely address Ergon's petition with regards to RIN costs"[180] and instead relied on the Burkholder memo "as the *sole basis* for its conclusion."[181] (emphasis added). The

[179] Confidential submissions by several small refineries made this assertion.
[180] *EWV-I*, 896 F3d at 613.
[181] *EWV-II*, 980 F.3d at 417, *rev'd on other grounds*.

court found that EPA was not arbitrary and capricious in relying on the Burkholder memo as one of many factors considered in the decision, but rather, failed to adequately illustrate how the analysis in that study applied to the circumstances at a particular small refinery (Ergon-West Virginia). On remand, EPA reached the same conclusion as in its first decision and again faced challenge from Ergon before the Fourth Circuit. The court, in *EWV-II*, reviewed EPA's post-remand denial, which again relied heavily on the Burkholder memo, and found that "EPA's post-remand discussion of Ergon's evidence connected the dots left unaddressed in its original decision[,]" because "EPA thoroughly discussed Ergon's purported evidence of hardship, explained why it rejected Ergon's arguments, and set out other factors that led it to reach an opposite conclusion."[182] Accordingly, in this proposed action, EPA has again evaluated the question in depth, starting with an evaluation of the underlying structure of the RFS program and RIN system to ascertain whether and how it might be possible for compliance with the RFS program to cause DEH. EPA then conducted a careful analysis of how the cost and value of RINs would be expected to flow through to consumers, and analyzed a substantial amount of data, including available local market-specific data, that show how the findings in the Burkholder memo regarding the refining industry as a whole are true for all obligated parties, including small refineries in general and individual small refineries in particular.[183] However, due to the confidential nature of much of the information included in SRE petitions, we cannot present any refinery-specific data in this proposal. Nevertheless, we have reviewed the information in the SRE petitions, and nothing presented in them leads us to conclude that the small refineries are affected by RFS compliance differently than other obligated parties or that they are not able to pass along the RFS compliance cost to consumers. However, to ensure we base our decision on the best data available, we are in this proposed action requesting additional market data, including additional data specific to any petitioning small refinery.

The small refineries also state that there are many diverse factors that affect each refinery's profitability and ability to recover the full cost of fuel production, including their RFS compliance costs. The small refineries cite to the 2011 DOE Study to support their assertion, quoting the following language:

The degree to which the costs burdening small refineries will be passed through to the market depends on many factors, including the market power and the relative cost level of a small refiner relative to other market participants.... The cost for small refiners to comply with the RFS2 requirements can be substantial.... Their limited product slates coupled with an inability to blend renewable fuels means that many of the small refiners must enter the market to buy RINs. The cost to meet their individual RVO makes this aspect the most significant cost of compliance.[184]

EPA understands that there are, indeed, many diverse factors that affect refinery profitability; however, RFS compliance costs are not among them.[185] The metrics DOE included in the scoring matrix were only intended to identify small refineries that may face adverse

[182] *Id.*
[183] *See supra,* Section IV.D.2.
[184] 2011 DOE Study at 22-23.
[185] *See supra*, Section IV.D.2.

business conditions,[186] and therefore potentially face DEH if they also experienced "a high cost of compliance relative to the industry average."[187]

The small refineries fail to acknowledge the fact that they may not be profitable or able to pass through the full cost of their fuel production *despite* their RIN costs being passed through. It is important to reiterate that independent market analyses, as well as EPA's own, support the premise that RIN costs are incorporated into the price of finished fuels.[188] This is to say that even *without* RFS compliance costs, these small refineries may not be profitable. This kind of economic hardship is not *caused* by the RFS program, but rather, by the refinery's business model, geographic location, or other factors independent of the RFS program. The CAA only speaks in terms of DEH caused by compliance with the RFS program. Congress tied SREs to compliance with the RFS program by using the language "compliance with the requirements of paragraph (2) would impose a [DEH]"[189] and "would be subject to a [DEH] if required to comply with paragraph (2)."[190] The CAA does not authorize or require EPA to subsidize through compliance exemptions any refinery whose economic hardship is not caused by compliance with the RFS program no matter the seriousness of the economic conditions the refinery may face, particularly since the magnitude of the RIN cost per gallon in comparison to typical refinery margins could turn the least profitable refineries into the most profitable ones.[191]

Additionally, the DOE language the small refineries quote comes from the "[o]ther observations from the interview process,"[192] which DOE "compiled through interviews with several industry participants, including two refineries, three importers, a fuel marketer, and a corn ethanol marketer."[193] This section does not state DOE's own conclusions, but rather summarizes what DOE heard from the stakeholders it reached out to. This language cannot be treated as DOE's findings, but rather, DOE's statement of the input it solicited and considered.

EPA believes the conclusions in the Burkholder memo are applicable to all gasoline and diesel fuel markets nationwide, and, therefore, also applicable to all refineries, including small refineries.[194] Nevertheless, some petitioning small refineries have provided refinery-specific supplemental information attempting to explain why the conclusions in the Burkholder memo don't apply to them. EPA has analyzed the supplemental information and found no evidence supporting the assertions from the petitioning small refineries that their RFS compliance costs are disproportionately greater than for other refineries or that they are not able to pass along the RFS compliance cost to consumers.[195] In fact, the data petitioners provided to EPA reflected the price behavior for both RINs and finished fuels that EPA would have expected based on

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[186] The adverse business conditions considered are quite varied and not directly related to the RFS compliance cost.
[187] 2011 DOE Study at 3.
[188] *See supra*, Section IV.D.
[189] CAA section 211(*o*)(9)(A)(ii)(I), paragraph (2) refers to the section where Congress provided the annual applicable renewable volume mandates.
[190] CAA section 211(*o*)(9)(A)(ii)(II).
[191] *See supra*, Section IV.D.2.b. *See also infra*, Section IV.D.3.e.
[192] 2011 DOE Study at 22.
[193] *Id.* at 21.
[194] *See supra*, Section IV.D.2.
[195] *See supra*, Section IV.D.2.

economic principles.[196] Additionally, other stakeholders with interest and expertise in RIN market behavior and RFS compliance have provided support for and approved of EPA's analysis and conclusions regarding RIN cost passthrough.[197]

b. The small refineries' situations are distinguishable from the findings provided in the Point of Obligation denial, and the Point of Obligation denial did not address small refineries.

Petitioners claim that EPA's assessment of RIN cost passthrough in the Point of Obligation denial covered three categories of parties: integrated refiners, non-obligated fuel blenders, and merchant refiners. The petitioners note that small refineries as a group do not fit neatly within any of these categories. They further claim that EPA's conclusions about merchant refiners' ability to recover their RIN costs were based on representations from Valero, which they note is a large, international refiner with efficiency, geographic range, and pricing power. The petitioners state that while these types of merchant refiners may be able to recover the cost of purchased RINs, small refineries without these characteristics cannot.

EPA recognizes that few, if any, small refineries (or any refineries) fit neatly into a single category of integrated refiner, non-obligated blender, and merchant refiner.[198] Rather, we explain that refiners, whether large or small, may operate as an integrated refiner, non-obligated blender, and/or a merchant refiner in various fuels markets and in different aspects of their business operations. EPA demonstrates that because both the RIN cost and the RIN discount are ultimately passed through to consumers for all three categories, the RFS program does not advantage or disadvantage any of these parties over the others, regardless of how much of their operations fall into one or more of these categories. Importantly, a small refinery's ability to recover its RIN costs in the price of the fuel it produces does not depend on factors such as geographic range or pricing power.[199] Instead, the data and analysis EPA presents demonstrate that the market prices for both refined products and blended fuel reflect the cost of acquiring the RINs necessary to satisfy the RFS obligation associated with the fuel. Merchant refiners do not need to exercise market power and demand a price that is higher than the market price to recover their RIN costs; all parties selling into these competitive markets are recovering the cost of acquiring RINs when they sell their fuel at the market price. Thus, although size and market power can be an advantage for reasons other than RFS compliance, they provide no advantage to non-small refineries in recovering their RFS compliance costs.

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[196] *See supra*, Section IV.D.2.

[197] *See supra*, Section IV.D.2. *See also* Letter from RaceTrac to Administrator McCarthy, August 17, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0014; Letter from QuikTrip to Administrator McCarthy, August 17, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0013; Presentation from Murphy USA to EPA, August 16, 2016, Docket Item No. EPA-HQ-OAR-2016-0544-0028. *See also* Comments from API on 2020 RFS Annual Rule, Docket Item No. EPA-HQ-OAR-2019-0136-0721.

[198] *See supra*, Section IV.D.2.c.

[199] *See infra*, Section IV.D.3.e.

c. EPA's assessment in the 2017 Point of Obligation Denial is out of date and not applicable in 2019 or 2020.

Many petitioners state that EPA could not rely on the conclusions of the assessment conducted in 2017 in the context of the Point of Obligation denial to evaluate their recent petitions. The petitioners state that the information considered in 2017 is now out of date and does not reflect the present realities of the fuels market.

We believe that the analyses conducted in 2017 continue to inform our understanding of the ways in which the RFS program affects small refineries and other fuels market participants, and we are not reconsidering or taking additional comments on EPA's decision not to initiate a rulemaking to change the point of obligation in the RFS program. The fact that the data reviewed in 2017 was consistent with what would be expected based on the design of the RFS program with its RIN system and economic principles is strong evidence that it is highly unlikely that the RFS program will cause DEH, and is strong evidence that the conclusions in that action remain true today. Our finding in that decision that the fuels market operates as we would expect in a competitive market remains relevant. As long as the fuels and RIN markets remain competitive, we do not anticipate that the RFS program will cause DEH to small refineries.

Nevertheless, in this proposed decision, we have considered more recent data since 2017—including data the small refinery petitioners themselves submitted—and we find that the more recent data are consistent with the data EPA reviewed in 2017.[200] These data continue to support our finding that both the RIN cost and the RIN discount are passed through to consumers and continue to show that the RIN market works in the same way for all market participants, including individual small refineries.

d. Revenue from RIN sales allows large retailers to undercut small refineries.

Petitioners claim that EPA had not considered clear evidence that revenue from RIN sales enabled large retailers such as Murphy USA to undercut the small refineries they compete with that are unable to sell RINs for a profit. The petitioners argue that large retailers (which are generally not obligated parties) can sell blended fuel at a lower cost than the cost of the petroleum fuel and renewable fuel they are composed of because of the revenue they receive by selling RINs. Small refineries must price their blended fuel at the same price as large retailers to be competitive, but they do not receive the benefit of revenue from RIN sales.

Contrary to the petitioners' claims, EPA has considered the ability for non-obligated blenders to sell RINs and to use the RIN sales revenue to discount the price of blended fuel while remaining profitable.[201] We present an illustrative example of how RIN prices affect integrated refiners (which is the role small refineries are taking in the fuels market when they are blending the petroleum fuel they produce with renewable fuel) and non-obligated blenders in Section IV.D.2.c. As shown in Tables IV.D.2.c-2 and 4, neither integrated refiners nor non-obligated blenders benefit from, or are harmed by, higher RIN prices.

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[200] The data, and the conclusions we have drawn from the more recent data, are presented in Section IV.D.2.d.
[201] *See supra*, Section IV.D.2.

The petitioners' description of blenders using revenue from RIN sales to enable them to offer lower prices for the blended fuel they sell is consistent with EPA's findings (i.e., the RIN discount).[202] We also recognize that competitive forces require small refineries selling blended fuel to sell at the market price (which reflects the passthrough of the RIN price as a discount to consumers). In their claims about the advantages that the RFS program provides to non-obligated blenders, however, the petitioners have not considered the impact of RIN prices on the market price for fuels.

When small refineries produce and sell blended fuel from the petroleum fuel that they produce, they are acting as integrated refiners for that volume of fuel. Generally speaking, integrated refiners are not able to sell the RINs associated with the renewable fuel they blend, as they need these RINs to meet their RFS obligations. But unlike non-obligated blenders, integrated refiners do not typically purchase petroleum fuel to produce blended fuel; instead, they are producing the petroleum fuel themselves. This means that for an integrated refiner, the cost of the petroleum fuel is not the market price for these products (which reflects the marginal cost of production of the fuels plus the cost of purchasing the RINs needed to satisfy the RFS obligation associated with the fuel), but rather simply the cost of production for the petroleum diesel fuel. The lower cost of the petroleum fuel relative to the market price for these products allows the integrated refiner to price its blended fuel competitively with non-obligated blenders and still maintain a positive margin for producing blended fuel even though they do not realize revenue from RIN sales.[203]

Both the economic principles and the data EPA reviewed support our finding that the RFS program does not advantage non-obligated blenders over integrated refiners. While RIN sales provide an additional source of revenue for non-obligated blenders, this is offset by the higher price (which reflects the RIN cost) for the petroleum fuel that the blenders pay to merchant refiners to produce blended fuel. Integrated refiners, who are producing petroleum fuel rather than purchasing them at the market price, have access to lower cost petroleum fuel but do not realize revenue from RIN sales. Thus, while the RFS program impacts these parties in different ways, neither enjoys an advantage or disadvantage over the other.

e. Large integrated refiners set the prices in fuels markets, undercutting small refineries on price because of their market position and because the large, integrated operations have no or lower RIN costs.

Petitioners claim that they compete in markets with large integrated refiners, and that they have no market pricing power relative to these parties. Petitioners also state that, because these large integrated refiners have no or lower RIN costs, they are able to undercut small refineries when they price their product. They further note several other advantages that large integrated refiners have relative to small refineries, such as a broader range of assets, economies of scale, and access to more fuels markets (including exports). We address each of these points in turn.

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[202] *See supra*, Section IV.D.2.

[203] A further description of the impact of the RFS program on merchant refiners, integrated refiners, and non-obligated blenders is provided in Section IV.D.2.c.

The market for gasoline and diesel fuel in the United States is extremely competitive.[204] EPA's finding that merchant refiners are able to pass through their RIN costs through higher market prices for the fuel they produce does not depend on merchant refiners having market pricing power in the markets where they sell fuel. Rather, we find that the market price for fuel reflects the RIN value, and therefore all parties in all markets that sell fuel recover their RIN costs when they sell their fuel (RIN cost passthrough).

In Section IV.D.2.c, EPA presented an example of the impact of higher RIN prices on merchant refiners, integrated refiners, and non-obligated blenders, and discussed the impact on each of these parties. In short, integrated refiners spend less money to purchase RINs than merchant refiners; unlike the non-obligated blenders they are competing with in the blended fuels market (i.e., large fuel retailers without refining or import businesses), they do not benefit from revenue from RIN sales. Merchant refiners do benefit from the higher market prices for gasoline and diesel fuel that are the result of higher RIN prices, but they must use this additional revenue to purchase RINs. Said another way, there is an opportunity cost when these integrated refiners blend renewable fuel with the petroleum fuel they produce instead of selling it unblended, because these parties sell blended fuel for a lower price than they could sell the petroleum fuel. This opportunity cost is equal to the savings these parties experience from acquiring RINs by blending renewable fuel rather than purchasing separated RINs.

The many factors mentioned by the petitioners, such as a broader range of assets (upstream, downstream, etc.), economy of scale, and access to more fuels markets, may in fact provide a competitive advantage to large integrated refiners. However, the fact that small refineries have continued to remain in the marketplace and compete with large integrated refiners is evidence of the fact that small refineries typically have other market advantages, such as access to local crude supplies and local markets lowering their distribution costs, specialty products, and niche markets with fewer competitors. None of these market advantages and disadvantages are the result of the RFS program. Each of these factors offered potential advantages (and potential liabilities) before the RFS program existed and continue to do so today. The petitioners have not presented any evidence, nor is EPA aware of any evidence, that would suggest that the RFS program has exacerbated any of the advantages large integrated refiners may have over small refineries.[205] In other words, the competitiveness of small refineries in the fuels market, be it favorable or unfavorable, does not change as a result of RFS compliance obligations.

On the other hand, granting SREs has provided small refineries a unique and significant competitive advantage. When small refineries are exempted from their RFS obligations, they continue to sell their petroleum fuel at the market price, which reflects the RIN cost via RIN cost passthrough. Thus, exempted small refineries recover the cost of the RINs (receive RIN revenue) through their product sales, but do not have any RIN costs when they are granted an exemption. The number of small refineries receiving exemptions, the total volume of gasoline and diesel fuel

[204] *See supra*, Section IV.D.2.

[205] EPA acknowledges that the Tenth Circuit has found that Congress may have understood large integrated refiners to have certain advantages, and EPA has cited that decision itself in support of its prior approach to SRE decisions. However, as noted, EPA does not believe that the available evidence supports the conclusion that small refineries are structurally disadvantaged by the RFS program itself.

exempted, the total value of the exemptions, and the value of the exemptions on a per gallon basis are shown in Table IV.D.3-1. This table also shows the average net refining margins (an indicator of profitability) for the exempted small refineries, for comparison with the value of the exemptions. The value of the exemptions is typically significant relative to the average net refining margin. For all exemptions granted from 2013 through 2018, the average value of the exemptions (6.76 cents per gallon) was approximately 64% of the average net refining margin of the exempted refineries (10.61 cents per gallon). Any exemptions granted in 2021 would likely be of even greater value since current RIN prices, and therefore the current RIN cost per gallon of fuel produced, are higher than RIN prices when the exemptions for 2013-2018 were granted.

Table IV.D.3-1: Value of SREs (2013-2018)

Year	Number of Grants Issued	Volume of Gasoline and Diesel Fuel Exempted (billion gallons)	Total Value of the Exemptions ($ Million)[206]	Value of Exemptions (¢ per gallon)	Average Net Refining Margin for Exempted Refineries (¢ per gallon)[207]
2013	8	1.98	118	5.98	-0.65
2014	8	2.30	105	4.57	4.98
2015	7	3.07	171	5.57	12.05
2016	19	7.84	676	8.63	2.11
2017	35	17.05	1,459	8.56	11.76
2018	31	13.42	558	4.16	17.00
Total	108	45.66	3,088	6.76	10.61

f. EPA's conclusion that there is parity between the cost of obtaining a RIN through blending and the cost of buying a RIN on the market is incorrect. It costs much more to buy RINs, which many small refineries must do.

Several petitioners claim that EPA's analyses are based on the assumption that the cost of obtaining a RIN through blending and the cost of purchasing a RIN is the same, and that this assumption is unfounded. To support this claim, the petitioners note that the cost to purchase RINs increased significantly in 2019, 2020, and 2021 and that the cost to purchase RINs in these years was much greater than the cost to blend renewable fuel. The petitioners further state that if there was no cost advantage to blending then there would be no reason for non-obligated parties to continue blending. Rather, these parties would stop blending if they could not recoup the loss by selling the RINs on the market.

We are aware that RIN prices increased significantly recently and we extended our analysis of the impact of RIN prices on the fuels market through the end of 2020 to determine

[206] Based on annual average RIN prices calculated by EPA from OPIS data for D3, D4, D5 and D6 RINs.
[207] EPA often grants exemptions in the year(s) following the year for which an exemption is requested. Because of this time lag, refineries sometimes financially account for the value of their exemption in the following year(s). Thus, the value of the exemptions for some refineries may be included in the net refining margin for the following year(s). For example, EPA granted some 2013 exemption in 2014 or later years, so the value of some 2013 exemptions may be included in financial statements for 2014 or later.

whether our previous findings on RIN cost passthrough were supported by more recent data.[208] We concluded that all the data available to EPA, including data submitted by the petitioners, continues to support EPA's findings on RIN cost passthrough.

EPA's finding that there is parity between the cost to obtain a RIN through blending and the price to purchase a RIN is not an arbitrary assumption. Rather, it is strongly supported by both economic principles and the fuels market data. As stated previously, the market for blended fuel is highly competitive. If the cost of obtaining a RIN by blending renewable fuel was lower than the market price for a RIN, we would expect to see new blenders enter the market and/or existing blenders increasing their blending to capitalize on this profit opportunity. This activity would result in an increase in the supply of RINs for sale until the demand price for a RIN was equal to the cost of obtaining a RIN through blending. Competitive market situations where the sales price of a good is appreciably higher than the cost to produce a good are short-lived, as market participants will increase production to take advantage of this opportunity until the supply price and demand price are equal.

The market data EPA reviewed support this finding as well.[209] The cost to obtain a RIN by blending renewable fuel is not simply the fixed and operating costs for fuel blending (which are relatively minor), nor is it simply the price difference between renewable fuel and the petroleum fuel into which they are blended (e.g., the price difference between ethanol and gasoline or between biodiesel and diesel fuel). Instead, the cost to a blender to obtain a RIN is the price difference between the cost of the petroleum fuel (e.g., gasoline or diesel fuel) and the renewable fuel used to produce blended fuel and the sales price of the blended fuel (e.g., E10 or B5). The data presented in Section IV.D.2.d demonstrate that the difference between the cost of the petroleum fuel and the renewable fuel used to produce blended fuel and the sales price of the blended fuel is equal to the market price for the RINs associated with the blended fuel.[210]

The finding that there is parity between the cost of obtaining RINs by blending renewable fuel and purchasing RINs does not mean that RINs do not provide an incentive for the blending of renewable fuel. While blending renewable fuel does not result in windfall profits for blenders (since the revenue from RIN sales is passed through to consumers in a discount on the price for blended fuel), RIN revenue lowers the effective cost of renewable fuel, allowing blenders to offer blended fuel containing renewable fuel at lower prices. The examples presented in Section IV.D.2.c illustrate this point. In the E10 blending example, the price of the gasoline is $1.44 per gallon and the price of ethanol is $1.50 per gallon, which is higher than the price of the gasoline (prices from Table IV.D.2.c-2). However, the RIN discount allows E10 to sell for $1.37 per gallon, which is lower than the price of the gasoline (line E4 from Table IV.D.2.c-2). Similarly, in the B5 blending example, the price for ULSD is $1.48 and the price for biodiesel is $3.66 (prices from Table IV.D.2.c-3). Here again the RIN revenue, when combined with the federal tax credit, allows B5 to sell for a lower price ($1.46 from line B5 in Table IV.D.2.c-4) than the price of diesel fuel. Fuel buyers are extremely sensitive to prices. The incentive for blenders to continue to blend renewable fuel when there is parity between the cost of obtaining a RIN through blending and the cost to purchase a RIN is not that the revenue from the sale of the RIN

[208] *See supra*, Section IV.D.2.
[209] *See supra*, Section IV.D.2.d.
[210] *See supra*, Figures IV.D.2.c-2 and 4.

represents a windfall profit, but rather that the RIN discount allows blended fuel to sell at a lower price relative to unblended fuel after passing through the revenue of the RIN sales to the consumer.

g. Single site refineries only have access to a limited market and are therefore at a disadvantage relative to large integrated refiners.

Several petitioners claim that because they own a single refinery and have access to limited markets for their fuels, they are at a disadvantage compared to large integrated refiners. The petitioners claim that because of their size, they cannot set the market price in such a way as to recover their RIN costs, nor can they sell their fuel into other markets if their local market prices are unfavorable.

As previously discussed, a refiner's ability to recover its RIN costs does not depend on the refiner's ability to set the market price for the fuel it produces.[211] Rather, because all parties have the same cost to acquire RINs, whether they acquire RINs through blending renewable fuel or by purchasing RINs, the market price for fuel reflects the cost of the RINs.

We are aware that the economics of refining crude oil to produce transportation fuel changes over time, and that fuels markets vary in their profitability relative to other markets. At times it can be an advantage to be in limited markets, and at other times not. Refiners with better access to pipelines and other low-cost ways to transport the fuel they produce are better positioned to react to changes in market dynamics, whether these changes are positive, negative, short-term, or long-term in nature. These varying circumstances, and any hardship they might cause to small refineries, are independent of and not caused by compliance with the RFS program.

We received claims of disadvantage from small refineries in isolated markets where they were the main supplier of fuel, from small refineries in markets readily accessible to many other refineries, and from small refineries in every situation in-between. The identical claims from such a broad diversity of refinery situations demonstrates that a small refinery's market has nothing to do with potential impacts from the RFS program. As a result of the nationwide RIN trading program, all refineries have equal access to the RINs they need for compliance with the RFS program and at the same nationwide price.

h. Refineries that produce primarily diesel fuel are at a disadvantage since they generally cannot blend as much renewable fuel into their product as can refineries that produce gasoline.

The claim that small refineries producing a disproportionately high amount of diesel fuel, relative to the amount of gasoline produced, suffer DEH from the RFS program presumes that parties that acquire RINs by blending renewable fuel do so at a lower cost than parties that purchase RINs. These small refineries generally assert that their ability to acquire RINs by

[211] *See supra*, Sections IV.D.2 and IV.D.3.e.

blending biodiesel or renewable diesel is limited relative to their competitors that have the ability to blend greater quantities of ethanol into the gasoline they produce.

As previously discussed, all parties have the same cost to acquire RINs, whether they do so by blending renewable fuel or by purchasing RINs.[212] A party's cost of acquiring RINs, therefore, is unrelated to its ability to blend renewable fuel. Further, it is not necessarily the case that greater quantities of renewable fuel can be blended into gasoline relative to diesel fuel. With the exception of very small quantities of higher-level ethanol blends such as E15 and E85, blending of ethanol into gasoline is limited to 10% by volume. Conversely, many parties regularly sell diesel fuel blended with up to 20% biodiesel or renewable diesel.[213] Parties blending 20% biodiesel or renewable diesel into diesel fuel would acquire more RINs than parties blending 10% ethanol into gasoline, especially after accounting for the higher equivalence values of biodiesel and renewable diesel.

V. Conclusion

Section 211(*o*)(9)(B) of the CAA and 40 CFR 80.1441(e)(2) give EPA the authority to grant an SRE petition only when a small refinery demonstrates it is experiencing DEH caused by compliance with the RFS program. Based on our detailed evaluation, careful consideration of all the available information, consultation with DOE, and consideration of the DOE study and other economic factors, EPA proposes to find that none of the 65 pending small refinery petitions have demonstrated DEH caused by the costs of compliance with the requirements of the RFS program.

The market-based design of the RFS program and the RIN-based compliance system have equalized the cost of compliance among all market participants, such that no refinery would face DEH from its RFS obligations.[214] We have evaluated an extensive amount of data and available literature and have concluded that the cost of RINs is the same for all obligated parties, whether the RINs are acquired by blending renewable fuel or by buying them on the market.[215] Hence, small refineries do not face a disproportionate cost of compliance when compared to other refineries, or to each other. Our analysis further shows that the costs of RFS compliance (i.e., RINs) are passed through in the prices of refined products. Hence, in recovering their RIN costs, refineries do not face economic hardship due to compliance with the RFS program. Finding no disproportionate cost of compliance and no economic hardship due to the RFS program, we conclude that small refineries do not face DEH. As such, EPA proposes to find that compliance with the RFS program does not cause DEH to small refineries and, accordingly, to deny all pending SRE petitions.

As stated above, this notice is not a final agency action for purposes of CAA section 307(b)(1). This action is not a rulemaking and is not subject to the various statutory and other provisions applicable to a rulemaking. Rather, the purpose of this proposal is to clearly articulate

[212] *See supra*, Sections IV.D.2 and IV.D.3.f.
[213] *See*, e.g., diesel fuel offerings by Pilot Flying J—the largest diesel fuel retailer in the United States—available at: https://pilotflyingj.com/fuel-prices.
[214] *See supra*, Section II.B.
[215] *See supra*, Section IV.D.2.

the Agency's current interpretation of its statutory authority to grant SREs and to present our analysis of all available data on RFS costs and market dynamics for public review and comment.

RENEWABLE FUELS ASSOCIATION

February 14, 2022

Preliminary Rebuttal to PNAS Report: "Environmental outcomes of the U.S. Renewable Fuel Standard" (Lark *et al.*)

A new report published today in the *Proceedings of the National Academy of the Sciences*, funded by the National Wildlife Federation, purports to examine the "environmental outcomes" of the Renewable Fuel Standard. In keeping with their previous "research" on biofuels and the RFS, the authors of this new paper precariously string together a series of worst-case assumptions, cherry-picked data, and disparate results from previously debunked studies to create a completely fictional and erroneous account of the environmental impacts of the Renewable Fuel Standard.

Below are a number of key facts that were purposely omitted from the new report by Lark *et al.*

FACT: Recent studies show that corn ethanol reduces GHG emissions by 40-50 percent compared to gasoline, even when emissions from hypothetical land use changes are included.

Today's corn ethanol already reduces GHG emissions by roughly half, on average, compared to gasoline. According to the Department of Energy's Argonne National Laboratory, typical corn ethanol provides a 44 percent GHG savings compared to gasoline, including land use change emissions.[1] Similarly, researchers affiliated with Harvard University, MIT, and Tufts University concluded that today's corn ethanol offers an average GHG reduction of 46 percent versus gasoline.[2] In addition, the California Air Resources Board (CARB) found that ethanol used in the state in 2020 reduced emissions by 41 percent, on average, compared to gasoline. From 2011 to 2020, CARB data show that the use of ethanol cut GHG emissions from the California transportation sector by 27 million MT CO2e, more than any other fuel used to meet the state's Low Carbon Fuel Standard requirements.[3]

FACT: The law establishing the RFS2 prohibits the use of crops from newly expanded cropland.

[1] Lee, U., Kwon, H., Wu, M. and Wang, M. (2021), Retrospective analysis of the U.S. corn ethanol industry for 2005–2019: implications for greenhouse gas emission reductions. *Biofuels, Bioprod. Bioref.*, 15: 1318-1331. https://doi.org/10.1002/bbb.2225

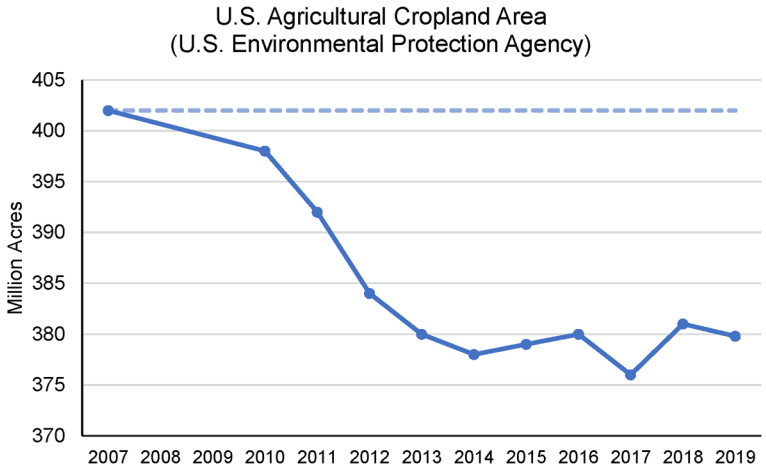
[2] Melissa J Scully *et al* (2021), Carbon intensity of corn ethanol in the United States: state of the science. *Environ. Res. Lett.* **16** 043001. https://iopscience.iop.org/article/10.1088/1748-9326/abde08

[3] CARB. "Low Carbon Fuel Standard Reporting Tool Quarterly Summaries." Viewed Nov. 20, 2021. https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

As acknowledged by Lark *et al*., "the RFS legislation contains several environmental safeguards to try to prevent perverse outcomes…" One of those environmental protections requires that biofuel producers may only use crops from agricultural land that had been cleared or cultivated prior to 2007. Thus, any crops produced on newly expanded cropland (i.e., after 2007) would not be eligible for biofuel production under the RFS.

FACT: According to EPA, U.S. cropland has decreased—not expanded—since the RFS2 was adopted in 2007.

To ensure compliance with the statutory limitation on cropland, EPA conducts an annual assessment of the amount of U.S. agricultural cropland. EPA's annual assessment shows that U.S. cropland has *receded* since the RFS2 was adopted in 2007, directly refuting the claim from Lark *et al.* that the RFS has somehow caused cropland to expand since 2007. According to EPA, the total amount of U.S. cropland in recent years has been 20-25 million acres *lower* (5-6 percent) than the amount of cropland in 2007 when the RFS2 was adopted (2020 and 2021 data have not yet been published by EPA).

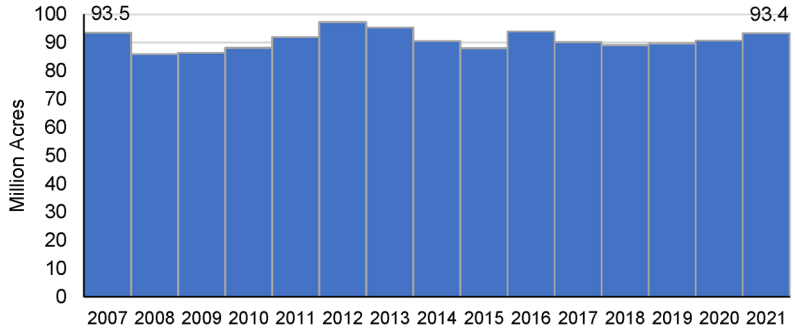


FACT: Corn acreage has been relatively flat since the RFS2 was adopted in 2007.

Looking specifically at corn acres, data from USDA show that the amount of land planted to corn in 2021 was essentially identical to the amount of land planted to corn in

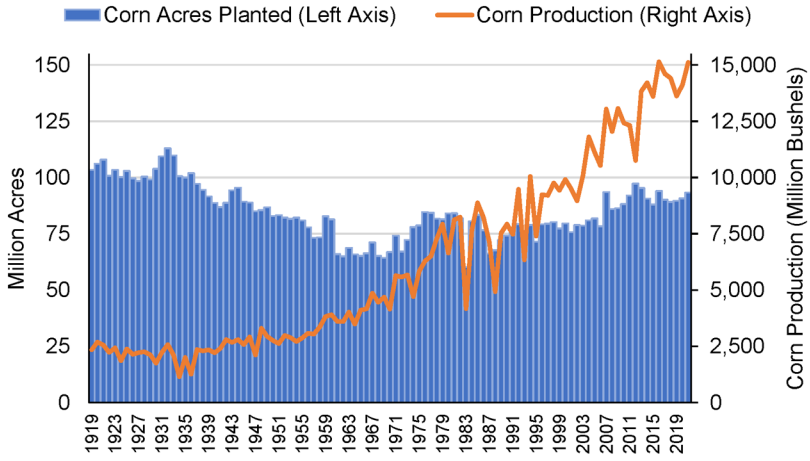
the spring of 2007 before the RFS2 was adopted. In fact, corn acres planted have been relatively consistent since 2007, averaging 91 million acres per year.

U.S. Planted Corn Acres, 2007-2021
(U.S. Department of Agriculture)



In addition, USDA data show that the amount of land dedicated to corn production today is well below historical levels and far below (18 percent) the peak level of 113 million corn acres in 1932.

U.S. Corn Acres Planted and Total Corn Production
(U.S. Department of Agriculture)



FACT: The additional corn supply needed to meet increased ethanol demand has come primarily from yield increases and secondarily from crop switching—not from acreage expansion.

As ethanol production has grown under the RFS program, the additional corn needed has come primarily from increased efficiency on existing cropland—not from expanding acreage.

For example, U.S. farmers planted 86 million acres of corn in 2008 (the first year of the Lark *et al.* study period) and harvested 78.6 million acres to produce a crop of 12.04 billion bushels. Thus, the average yield that year was 153.3 bushels per acre. In 2018 (the record-high year for ethanol production), farmers planted 89.1 million acres and harvested 81.3 million acres to produce a crop of 14.42 billion bushels. The average yield in 2018 was 176.4 bushels per acre.

Thus, farmers produced 2.38 billion bushels more (20 percent) in 2018 than in 2008, but used only 2.7 million more harvested acres (3 percent) to do it. Importantly, the slight increase in corn acres came from reductions in planted acres for other crops (like wheat and cotton), not from expanding cropland. Yield growth alone accounted for about 80 percent of the corn production increase between 2008 and 2018. Meanwhile, corn use for ethanol was 2.32 billion bushels higher in 2018 than in 2008, meaning the increase in corn production slightly outpaced the increase in corn use for ethanol.

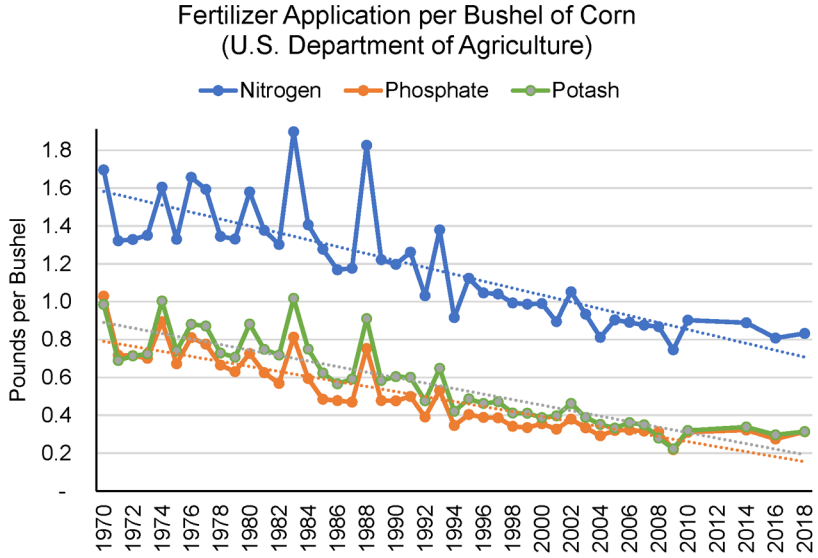
	2008	2018	Change	% Change
Total Agricultural Cropland (m. acres)[1]	402.0	381.0	-21.0	-5.1%
Corn Acres Planted (m. acres)[2]	86.0	89.1	3.1	3.6%
Corn Acres Harvested (m. acres)	78.6	81.3	2.7	3.4%
Yield per Acre (bu. per acre)	153.3	176.4	23.1	15.1%
Corn Production (m. bu.)	12,043	14,420	**2,377**	19.7%
Ethanol Production (m. gal.)[3]	9,309	16,091	6,782	72.9%
Corn Use for Ethanol & Co-products (m. bu.)[4]	3,325	5,646	**2,321**	69.8%

1. EPA
2. USDA
3. EIA
4. RFA based on average ethanol yield per bushel

FACT: The amount of fertilizer required to produce a bushel of corn has fallen dramatically in recent decades.

The Lark et al. paper suggests that the RFS is somehow responsible for "increasing annual nationwide fertilizer use by 3 to 8%." However, data from USDA show that total fertilizer (nitrogen, phosphate, and potash) application on corn in recent years is slightly less than the total amount of fertilizer typically applied to corn in the 1970s and 1980s. However, because today's corn output is so much larger than in the 1970s and 1980s,

the amount of fertilizer required to produce a bushel of corn has dropped precipitously. USDA data show that nitrogen fertilizer use per bushel is down more than 50 percent since 1970, while phosphate and potash use are each down nearly 70 percent. Clearly, fertilizer use for corn production has not increased since the RFS2 was adopted in 2007.



FACT: The methodology used by *Lark et al.* to estimate land use changes is highly flawed and has been rejected after rigorous critique by the scientific community.

Despite the fact that EPA and USDA data show no overall cropland expansion since the RFS2 was adopted, Lark et al. claim that "native" grassland with high carbon storage has been converted to corn production because of the RFS. This claim is based on previous studies conducted by Lark and others that rely on comparisons of satellite imagery from different time periods.

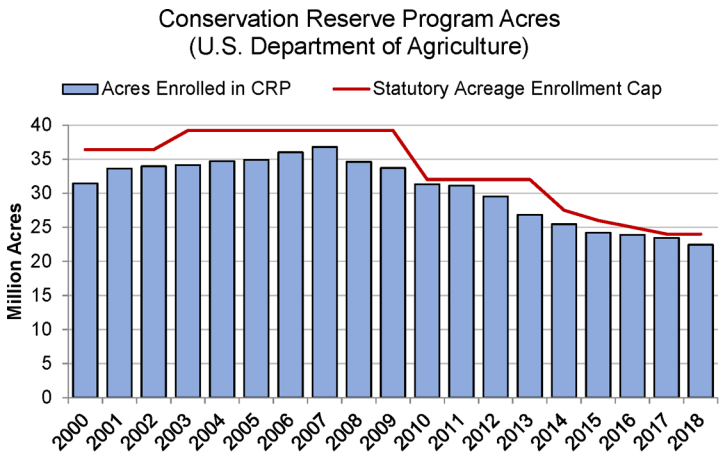
If, for example, a satellite image from 2008 shows a particular parcel of land is covered in grass, but a satellite image from 2016 shows that same parcel is planted to corn, the authors would treat this as a conversion of "native" grassland to corn. Using an opaque

methodology, they then assign that "new" corn production to ethanol and allocate the assumed emissions from the land conversion to the ethanol. There are multiple problems with this approach.

First, the satellite tools used by Lark and others have great difficulty distinguishing between different land cover types. For example, one tool relied heavily upon by Lark et al. (USDA's "Cropland Data Layer," or CDL) often cannot tell the different between wheat, alfalfa hay, grass, and other land cover types. And even if the tools could identify land covered in grass with a high degree of certainty, they cannot distinguish between grass pastureland, grass hay, land enrolled in the Conservation Reserve Program, and "native" grassland. Of course, these land cover types would have much different carbon storage profiles. Yet, Lark et al. treat all of these land cover types (sometimes also including wheat, alfalfa and other crops) as "native" grassland. USDA, which maintains several of the tools used by Lark et al., has warned that, "Unfortunately, the grassland-related categories have traditionally *had very low classification accuracy* in the CDL."

Second, the authors attempt to characterize these supposed land cover changes as "empirical" and "observed," suggesting that they actually verified these supposed conversions with their own eyes. This is not the case. Rather, they are relying on highly uncertain and error-prone satellite images for their purported "empirical observations" of land use changes.

In addition, any transitions of non-cropland into cropland since the RFS2 was adopted are most likely explained by expired CRP land returning to cropland, not conversion of "native" grassland. Yet, from a carbon emissions standpoint, the Lark et al. methodology treats a transition of CRP ground back to cropland the same as a conversion of native grassland to cropland. In any case, it is incorrect to argue that the return of some former CRP land to crop production is solely due to the RFS. Rather, Congress has repeatedly lowered the cap on the amount of land eligible for enrollment in CRP, dropping the limit from 39 million acres in 2008 (the first year of the Lark et al. study period) to just 25 million acres in 2016 (the final year of the study period). Thus, it should be no surprise that some of the land no longer eligible for CRP enrollment returned to crop production.



The obvious flaws in the methodology used by Lark *et al.* and several of the underlying studies have been examined and critiqued in detail by, among others, the following:

- Remote sensing experts at Southern Illinois University
  - https://ethanolrfa.org/file/1833/SIUE-Rebuttal-on-USDA-CDL-Use.pdf
  - https://ethanolrfa.org/file/1834/SIUE-Review-of-Land-Use-Change-Literature-07-2019.pdf

- Energy economists and lifecycle assessment experts from Northwestern University, the Dept. of Energy's Argonne National Laboratory, DOE's Oak Ridge National Laboratory University of Illinois-Champaign/Urbana, and University of Illinois-Chicago
  - https://ethanolrfa.org/file/2005/ijgi-10-00281.pdf
  - https://ethanolrfa.org/file/807/Measured-extent-of-agricultural-expansion-depends-on-analysis-technique_Dunn-et-al_2016.pdf
  - https://ethanolrfa.org/file/1447/1373e8a3f091431ad5_g0m6ibjcr.pdf
  - https://ethanolrfa.org/file/2001/LUC-Ethanol-Plant-Proximity-Crop-Prices_Li-et-al_2018-12.pdf

- Economists at the Renewable Fuels Association
  - https://ethanolrfa.org/file/1932/USDA-Data-Show-Cropland-Reductions-in-Counties-with-Ethanol-Plants-from-1997-2012.pdf
  - https://ethanolrfa.org/media-and-news/category/news-releases/article/2015/04/university-of-wisconsin-study-based-on-shaky-foundation-of-faulty-data-and-conclusions
  - https://ethanolrfa.org/file/1814/Wisconsinethanolresponse11.15.pdf

Senator DUCKWORTH. Thank you.

I also ask unanimous consent to include in the record for this hearing reports from Environmental Health and Engineering. It is a report addressing biofuels and greenhouse gas reduction; the Life Cycle Associates 2020 report documenting the 1 billion metric tons of GHG reductions attributed to biofuel use since 2007.

Third, a study published by USDA scientists in 2021 titled The Greenhouse Gas Benefits of Corn Ethanol: Assessing Recent Evidence, which found climate smart agriculture practices reduce emissions. And finally, fourth, a study published by Argonne National Laboratory that found corn ethanol is reducing the carbon footprint and diminishing GHG emissions.

Senator CARPER. Is there objection?

Hearing none, so ordered.

[The referenced information follows:]

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ENVIRONMENTAL RESEARCH
LETTERS

TOPICAL REVIEW

Carbon intensity of corn ethanol in the United States: state of the science

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Abstract

The carbon intensity (CI) of corn ethanol, the primary renewable fuel used in transportation, has been actively researched and quantified over the last three decades. Reliable estimates of greenhouse gas (GHG) emissions for corn ethanol are important since these values help determine significant policy and market decisions on state, national, and international levels. We reviewed well-to-wheel GHG life cycle analyses (LCAs) for corn ethanol and evaluated models, input data, and results for farming, fuel production, co-product credit, land use change (LUC), transport of feedstock and fuel, tailpipe, and denaturant. Compared to earlier analyses, recent LCAs for corn ethanol contain updates to modeling systems and data that reflect: (a) market-driven changes in corn production that lowered the intensity of fertilizer and fossil fuel use on farms; (b) more efficient use of natural gas and recent electric generation mix data for energy consumed at ethanol refineries, and (c) LUC analyses based on hybrid economic-biophysical models that account for land conversion, land productivity, and land intensification. LCAs that include these latest developments yield a central best estimate of CI for corn ethanol of 51.4 $gCO_2e\ MJ^{-1}$ (range of 37.6–65.1 $gCO_2e\ MJ^{-1}$) which is 46% lower than the average CI for neat gasoline. The largest components of total CI are ethanol production (29.6 $gCO_2e\ MJ^{-1}$, 58% of total) and farming practices net of co-product credit (13.2 $gCO_2e\ MJ^{-1}$, 26%), while LUC is a minor contributor (3.9 $gCO_2e\ MJ^{-1}$, 7%). Market conditions that favor greater adoption of precision agriculture systems, retention of soil organic carbon, and demand for co-products from ethanol production may lower the CI of corn ethanol further. Continued refinement of models to account for co-products, conservation of soil carbon, and direct and indirect LUC is expected to produce ever more accurate estimates in the future.

1. Introduction

The Renewable Fuel Standard (RFS) program, authorized by the Energy Policy Act of 2005, aims to reduce greenhouse gas (GHG) emissions, expand the nation's renewable fuels sector, and reduce reliance on imported oil [1]. The RFS required that transportation fuels sold in the United States contain 7.5 billion gallons (BG) of renewable fuels by 2012 [2]. In 2007, the Energy Independence Security Act expanded the RFS (referred to as RFS2) and required transportation fuels to contain 36 BG by 2022, with 15 BG coming from conventional biofuels and 21 BG from advanced biofuels [3].

Ethanol produced from corn starch (hereafter 'corn ethanol') is currently the primary conventional renewable fuel used in transportation fuels [4]. Ethanol demand in the United States increased from 3.6 BG in 2004 to 14.4 BG in 2019 [5]. Given this significant expansion, accurate characterization of the GHG profile of corn ethanol is important for evaluating impacts of the RFS and related low carbon fuel

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initiatives. Estimates for the carbon intensity (CI) of corn ethanol over the past three decades range from approximately 105 grams of carbon dioxide equivalent emission per megajoule of energy ($gCO_2e\ MJ^{-1}$) in 2009 to approximately 52 $gCO_2e\ MJ^{-1}$ in more recent years [2, 6–14]. The estimates published since 2010 represent a reduction of approximately 20% to 40% in GHG emissions relative to conventional 2005 gasoline, the benchmark comparison in life cycle analyses (LCAs) published by the Environmental Protection Agency (EPA) and the United States Department of Agriculture (USDA) [2, 7]. Identifying the basis of these estimates and reasons for the differences among them is important because the CI values are used to inform significant policy and market decisions on state, national, and international levels.

To address this need, we conducted a state of the science review of the CI for corn ethanol in the United States and derived an evidence-based central CI estimate and credible range as of 2020. We compared our result to CI values for corn ethanol reported in generally accepted, widely used LCAs published as of 2010 and identified the principal reasons for any notable differences observed. This review of CI for corn ethanol is intended to inform analyses of the role for corn ethanol as a transportation fuel in the decarbonization of the United States economy and to facilitate communications on biofuel production, policy, and use.

2. Methods

We searched the peer-reviewed and grey literature to identify existing well-to-wheel LCA analyses, models, parameter values, and data on overall corn ethanol CI and its components for the United States. We focused on well-to-wheel LCAs because they use a generally accepted approach for assessing GHG impacts of a transportation fuel and examine each stage of corn ethanol production and use [15]. We also focused on stand-alone analyses of LCA components to capture the latest developments in LCA models and the associated input parameters. To supplement the literature review, we interviewed over two dozen biofuel LCA experts in academia, government, not-for-profit, and commercial organizations in the United States and Canada. This search strategy yielded 23 LCA models [2, 7–14, 16–26] and over 30 supporting publications that we used to develop a structure for subsequent critical review and analysis.

We consolidated the numerous LCA components into nine emission categories: farming, co-product credit, fuel production, land use change (LUC), rice methane, livestock, fuel and feedstock transport, denaturant, and tailpipe. Preliminary review of the data showed that farming and co-product credits, fuel production, and LUC account for over 90% of the CI of corn ethanol. For each of those major categories we: (a) critically reviewed previously developed CI estimates; (b) evaluated and recalibrated inputs and assumptions to reflect the current state of the science; and (c) selected models and parameters deemed to provide the most reliable results based on our analysis of their strengths and weaknesses (described in the results). The screening process generally produced fewer than ten CI values for each emission parameter, all of which we considered equally likely and valid. We defined the minimum and maximum values as the range of credible values for each parameter and the midpoint between the minimum and maximum values as the central best estimate. Information on methods employed for each of the major categories is provided next.

For LUC, we critically reviewed 26 CI values published since 2008 and evaluated the underlying agro-economic model, economic data year, yield price elasticity (YDEL), and incorporation of land intensification [2, 7–10, 12–14, 27–40]. We assigned a binary indicator of current best practice (yes or no) to each LUC model or parameter using criteria informed by peer-reviewed literature, empirical analysis, and input from our panel of external experts. Next, we selected the CI outputs for international LUC (iLUC), domestic LUC (dLUC), and total LUC from the sources that met our criteria for best practice. We also calculated an updated dLUC emission value using the recently released 2020 Argonne National Lab (ANL) Carbon Calculator for Land Use Change from Biofuels Production (CCLUB) model. We summed the values for iLUC and dLUC to develop a central estimate and credible range for total LUC.

For farming, we primarily drew upon analyses and data in the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model, the most widely used tool and database over the prior 10 years for assessing GHG emissions from corn ethanol in the United States [41]. We reviewed recent GREET-based assessments [7, 9, 10, 12–14] and compared their emission estimates to calibrated data from the Ecoinvent database version 3.5 [42]. We selected Ecoinvent as a useful and transparent database to thoroughly assess farming emissions because: (a) its data sources and assumptions are well documented; (b) it is publicly available; and (c) when used in conjunction with LCA software, it allows for assessment of process contributions, identification of key drivers of emissions, determination of the impact of assumptions and parameters on the analysis, and scenario analysis. We calibrated the Ecoinvent data to reflect current farming practices more accurately. We determined the range and central estimate of farming emissions from the parameter values in GREET and Ecoinvent. To account for farming co-product credits, we followed methods in accordance with the International Organization for Standardization (ISO) 14044

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standard for LCAs and determined a credible range and central estimate [43].

For ethanol production, we relied upon documented energy emissions factors and data on regional electricity grid mixtures and process fuels used to power refining and co-product operations. We evaluated fuel production model assumptions used in well-to-wheel LCAs and compared them to current processes of the United States corn ethanol refining industry. Following the model evaluation, we derived a range and central estimate for fuel production emissions and validated our estimates using data from an ANL 2018 survey that collected responses from 65 corn ethanol dry mill facilities located across 17 states in the United States [44].

For the remaining direct GHG emissions categories (fuel and feedstock transport, tailpipe, and denaturant emissions), we derived a range and central estimate from the information provided in the selected attributional and consequential LCAs included in our analysis. Attributional LCAs consider the direct emissions associated with the full supply chain of corn ethanol production and its consumption [2]. Consequential LCAs consider direct as well as indirect emissions from potential changes to resources (e.g. rice and livestock) expected to result from changes in the production or consumption of corn ethanol [2]. To calculate the CI of corn ethanol in our study, we followed an attributional approach (i.e. included direct emissions), with the addition of consequential LUC emissions, since those emissions have been historically considered as large contributors to the CI of corn ethanol [2, 7, 10, 27]. Thus, we calculated the total CI of corn ethanol by summing the central estimates for seven emission categories (LUC, farming, co-product credit, fuel production, fuel and feedstock transport, tailpipe, and denaturant), as well as the upper and lower bounds of the credible ranges.

3. Results

All well-to-wheel GHG LCAs identified by our literature search were produced by government organizations or investigators, while studies on specific components of LCAs, such as LUC and farming emissions, were primarily published by academic-based investigators. Of the former, we identified three LCAs issued by California Air Resources Board (CARB) [8–10]; one by EPA [2]; two by USDA [7, 26]; and annual reports from ANL for 2010–2020 [11–14, 16–25]. The total CI values for corn ethanol from most of those LCAs are presented as a time series in figure 1, along with contributions from the three principal components: corn production and transportation (i.e. farming), ethanol production and transportation, and LUC. The plot demonstrates two-fold variability among CI values for corn ethanol over the 20 year period, but also convergence toward lower CI values for corn ethanol in total and among each of the principal components.

Examination of figure 1 shows that some of the variability among estimates of total CI over time is explained by differences in system boundaries of the LCAs. The LCAs released by ANL from 1990 through 2005 only consider GHG emissions arising directly from the life cycle of corn ethanol, i.e. from farming and ethanol production, whereas LCAs published after 2005 also consider emissions that could occur indirectly in response to changes in corn ethanol production and demand, i.e. LUC [2]. Expanding the system boundary to include LUC increases the CARB and EPA estimates of total CI for corn ethanol by 40% to 55% over the combined CI of farming and ethanol production [2, 8–10]. In comparison, the ANL and USDA estimates of CI associated with LUC are lower and equivalent to approximately 15% to 25% of the combined CI for farming and ethanol production [7, 11–14]. Estimates for LUC CI are reviewed in section 3.1.

Further examination of figure 1 shows a consistent, but not monotonic, decrease in CI for farming and ethanol production which also explains a portion of the variability in total CI values over time. Estimates of the CI for both farming and ethanol production decreased by approximately 50% from peaks of 34 $gCO_2e\ MJ^{-1}$ and 64 $gCO_2e\ MJ^{-1}$ in 1990, respectively [6]. The decrease in farming emissions is primarily a result of practice improvements, such as a 35% reduction in nitrogen fertilizer use and 40% reduction in fossil fuel consumption from 1990 to 2005 [40]. The reduction in GHG emissions from ethanol production stems primarily from more efficient use of energy at corn ethanol plants with energy use intensity dropping by approximately 50% (15 to 7.5 gigajoules per cubic meter of ethanol) from 1990 to 2010 [40]. Except for the analysis by CARB in 2015, CI estimates published after 2010 have converged on approximately 30 $gCO_2e\ MJ^{-1}$ for ethanol production and 13 $gCO_2e\ MJ^{-1}$ for farming, with the latter including a co-product credit from displacement of conventional animal feeds such as corn, soybean meal, and urea by distillers grain solubles (DGS) generated as a by-product of ethanol production.

We review variability of the CI estimates for LUC, farming, ethanol production, and remaining categories in the remainder of this paper. Those evaluations focus on LCA analyses published as of 2010 and relevant peer-reviewed papers. These inclusion criteria exclude earlier LCAs from ANL and CARB that are superseded by more recent analyses, while capturing the only LCA published by EPA and key publications on LUC and petroleum-based gasoline. In addition, we excluded ANL LCAs prior to 2013 since they were not available in a transparent format, and their LCAs from 2013 and 2015 since they are incorported into CARB's 2015 and USDA's 2018 analyses, respectively.

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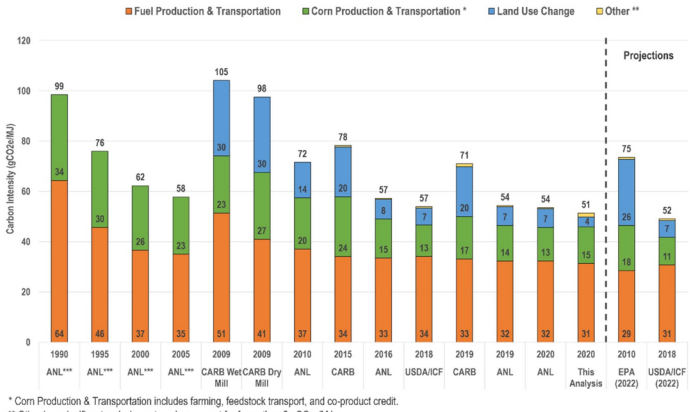


Figure 1. Timeline of estimated corn ethanol life cycle GHG emissions for 1990 through 2020 with projections out to 2022.

We selected LCAs by ANL we thought to be representative of more recent practices. We also excluded USDA's 2017 LCA since their 2018 analysis was an amended and updated analysis which relied upon the same ANL 2015 modeling.

Results from the LCAs as of 2010 included in our analysis are summarized in table 1. Aggregate CI scores for corn ethanol range from 52.1 to 78.3 $gCO_2e\ MJ^{-1}$, including the two projections for 2022. The net CI for farming, ethanol production, and co-product credits comprise approximately 70% of the total CI in each analysis. Transportation of feedstock and ethanol as well as tailpipe emissions from end-user vehicles were also similar across the LCAs and together account for about 4 $gCO_2e\ MJ^{-1}$ and 7% of total CI. The LCAs differed in the remaining emissions categories. LUC CI varied four-fold among individual analyses, from 6.7 to 26.3 $gCO_2e\ MJ^{-1}$. Emissions associated with addition of a denaturant to ethanol were considered in only two of the LCAs and indirect effects on rice methane emissions and livestock emissions were considered in only three of the LCAs. We examine these emission categories in the following sections, beginning with LUC.

3.1. Land use change (LUC)

We identified 26 CI values for LUC of corn ethanol published since 2008. As shown in figure 2, these values decreased from 104 $gCO_2e\ MJ^{-1}$ to generally less than 10 $gCO_2e\ MJ^{-1}$ from 2008 to 2020 [2, 7–10, 12–14, 27–40]. The LUC values appear to be converging although a moderate degree of variability remains among models and analyses. Variability among the LUC estimates stem primarily from differences in four major elements that comprise these CI values: the agro-economic model, economic data year, YDEL, and land intensification. Our evaluation of these elements is presented next and details are provided in tables S.1–S.4 (available online at stacks.iop.org/ERL/16/043001/mmedia) in the supplemental materials.

3.1.1. Agro-economic models

Agro-economic models predict demand for agricultural commodities globally in response to changes in supply and are used to assess LUC following increases in production of biofuels [45]. The LCAs for corn ethanol that we reviewed rely upon one of three agro-economic models: Forestry and Agricultural Sector Optimization Model (FASOM), Food and Agriculture Policy Research Institute (FAPRI), and Global Trade Analysis Project-Biofuels (GTAP-BIO). While having a common endpoint, these models differ in their geographic scope, method used to predict land conversion, and consideration of land cover categories. These characteristics and others translate to comparative strengths and weaknesses of the three models.

As shown in table S.1, EPA (2010) relied upon FASOM to characterize LUC within the United States (dLUC) and FAPRI elsewhere in the world (iLUC) [2]. FASOM was developed with a focus on dLUC and has not been widely adopted in LCAs for corn ethanol [46, 47]. Further examination of table S.1 shows that

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Table 1. GHG emissions ($gCO_2e\ MJ^{-1}$) reported by LCAs for corn ethanol produced in the United States.

Model	CARB 2015	ANL 2016	USDA 2018	CARB 2019	ANL 2019	ANL 2020	EPA 2010 projection for 2022		USDA 2018 projection for 2022
GREET model	CA-GREET 2.0 (GREET1_2013)	GREET1_2016	GREET1_2015	CA-GREET 3.0 (GREET1_2016)	GREET1_2019	GREET1_2020	GREET_1.89c (2009)	GREET1_2015	
				GHG emission categories					
Fuel production	30.2	32.3	32.7	30.7	31.3	31.4	26.5		29.4
Farming (domestic and international[a], including chemicals)	34.4	27.7	22.8	28.0	26.0	25.6	16.0		21.3
Co-product credit	−12.6	−12.2	−12.1	−12.6	−13.4	−13.5	Included in farming emissions	−11.4	
Fuel and feedstock transport	5.9	2.7	3.3	3.9	2.5	2.2	4.0	2.5	
Tailpipe	0.0	0.5	0.6	0.1	0.5	0.5	0.8	0.6	
Total land-use change (domestic and international)	19.8	7.9	6.7	19.8	7.5	7.4	26.3	6.7	
Rice methane (domestic and international)	—	—	1.4	—	—	—	1.8	1.4	
Livestock (domestic and international)	—	—	1.6	—	—	—	−0.3	1.6	
Denaturant	0.6	—	—	1.1	—	—	—	—	
Total CI in $gCO_2e\ MJ^{-1}$	78.3	58.9	57.0	71.0	54.4	53.6	75.1		52.1

[a] International farming only considered by USDA and EPA.

ANL: Argonne National Lab.

CARB: California Air Resources Board.

EPA: United States Environmental Protection Agency.

GREET: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation model.

GHG: Greenhouse gas emissions.

USDA: United States Department of Agriculture.

CI: Carbon intensity.

$gCO_2e\ MJ^{-1}$: Gram carbon dioxide equivalent emission per megajoule [2, 7, 9, 10, 12–14].

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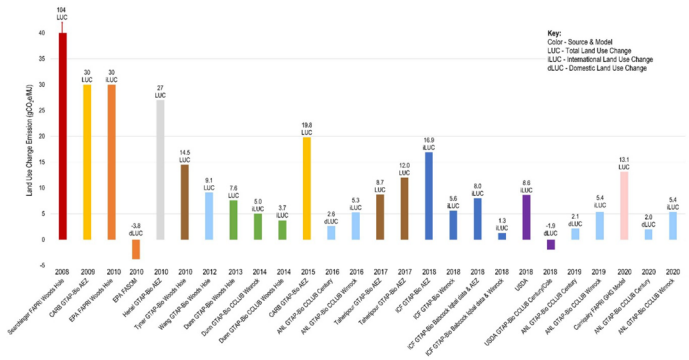


Figure 2. Timeline of estimated GHG emissions associated with corn ethanol-related LUC, 2008–2020.

FAPRI was used in three analyses that we reviewed, one for iLUC only and for total LUC in the other two. GTAP-BIO was used to estimate dLUC, iLUC and total LUC in the remaining 22 analyses.

For land conversion, FAPRI predicts changes in crop acres by country globally, but does not have land type interactions built into the model [2]. To predict land specific crop acres, FAPRI relies upon Moderate Resolution Imaging Spectroradiometer (MODIS) satellite imagery data which has been demonstrated to misclassify agricultural and non-agricultural lands, resulting in inaccurate predictions of land types that convert to cropland and unreliable emission estimates associated with LUC [2, 47]. In contrast, land conversion in GTAP-BIO is based upon hybrid economic-biophysical models that account for both the quantity and quality of available agricultural land to predict how much land of each land cover category is actively used in production and how much land is idle during a specific time period [45, 48]. GTAP-BIO accounts for climate-specific crop yields and three soil quality indicators to generate land productivity and land supply curves that are calibrated to historical crop productivity figures [49]. GTAP-BIO also considers multiple categories of land use, including idle cropland and cropland pasture, that allow for application of land use-specific GHG emission factors. This feature is particularly important for simulating return to production of land in the USDA Conservation Reserve Program [50].

Based on our review of the literature, GTAP-BIO appears to be the field-leading model for LUC because it addresses both dLUC and iLUC, predicts LUC for specific land types using both economic and physical data, is incorporated into the generally accepted GREET model from ANL, and has been adopted for use in LUC analyses for the California Low Carbon Fuel Standard (LCFS) [51]. For these reasons, we marked LUC estimates derived from the GTAP-BIO model as meeting our best practice criteria (table S.1).

3.1.2. Economic data year

The economic data year is the baseline point in time used in agro-economic models for estimating LUC of corn ethanol. The year of the economic data is significant because the agro-economic model is 'shocked' with an expansion of a specified volume of corn ethanol. The volumes which shock the model are determined by the difference between 15 BG, the RFS2 mandated volume target for conventional biofuels, and the volume of ethanol produced in the United States during the specific economic data year [1, 52]. Three world economic data years were used in the analyses that we reviewed: 2001, 2004, and 2011. The modeled expansion in production volume of corn ethanol is approximately 13.25 BG for economic data year 2001, 11.6 BG for 2004, and 1.1 BG for 2011. Eighteen of the 26 LUC analyses that we reviewed used 2004 as the economic data year, while four used 2001, and one used 2011. We selected 2004 as the most appropriate economic data year for this review, because it captures the largest period of corn ethanol volume expansion in the United States and is relied upon the most frequently. We marked models using 2004 as meeting our best practice criteria (table S.1).

3.1.3. Yield price elasticity

YDEL describes the percentage change in crop yield per unit of land per percentage change in price for

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the crop and is a key driver of LUC outputs from agro-economic models [53]. The CARB LCFS expert workgroup recommended a YDEL of 0.25 for the United States and 0.3 for Brazil and Argentina, where multiple cropping is likely to occur, and 0.175 for countries that do not practice multiple cropping [54]. Multiple cropping is defined as growing two or more crops on the same land in the same season or year [55]. Taheripour *et al* (2017) reviewed crop yield data from 19 regions around the world and derived a recommended YDEL range of 0.175–0.325 [35, 56]. We examined YDEL for corn reported in 20 studies published from 1976 to 2017 and calculated a simple average of 0.23 (table S.2) [2, 28, 34, 35, 57–66]. From these data, we determined a YDEL central best estimate of 0.25 and credible range of 0.175–0.325. Eighteen analyses that we reviewed had YDEL values within this range and we marked them as meeting our best practice criteria (table S.1).

3.1.4. Land intensification

Land intensification is the practice of using existing cropland more efficiently and is defined as activities undertaken with the intention of enhancing the productivity or profitability per unit area of land [67]. Examples of land intensification include yield improvement, multiple cropping, reduction of agricultural land in fallow, conversion of other unused cropland to crop production, and reduction in temporary or mowed pasture [68]. According to an empirical analysis of agricultural land use across the globe, land intensification accounted for two thirds (49.1/73.1 million hectares) of the observed increase in harvests from the period 2004–2006 to 2010–2012 rather than conversion of timberland and pasture to farm land [68], while the United States corn ethanol production increased over three-fold during that period (4.0–13.5 BG) [5]. Similarly, an empirical analysis of agricultural land from 2003 to 2013 found the ratio of harvested area over available land area increased in 17 of the 19 worldwide regions, indicating that land intensification increased globally rather than only in a minor fraction of locations [56]. Another empirical study found that from 2002 to 2017, agricultural land area in the United States declined by 38 million acres while land intensification increased harvested area by 17 million acres and annual ethanol production increased by 13.8 BG [5, 69]. These studies indicate that land intensification is an important and common response to increased demand for corn ethanol production. Only five of 26 analyses that we reviewed considered land intensification and we marked them as meeting our best practice criteria (table S.1).

In addition to reviewing previously developed LUC estimates, we calculated an updated dLUC CI value to incorporate the recently released 2020 CCLUB model developed by ANL into this review and applied land transformation parameters [33]. The land transformation parameters considered regionally specific land transformation elasticities and land-specific costs of converting pasture or forest to cropland [33]. We set 2004 as the economic data year and ran the 'Corn Ethanol 2013' feedstock to fuel pathway which was calibrated with land transformation parameters. Additional inputs for the CCLUB run are provided in the table S.3. Our analysis returned a CI for dLUC of -2.3 gCO_2e MJ^{-1}.

The dLUC, iLUC, and total LUC CI values identified as meeting our best practice criteria are shown in table 2. We summed the two dLUC values with the iLUC values selected from our critical review to determine an overall credible range of LUC of -1–8.7 gCO_2e MJ^{-1} from which we calculated a central best estimate of 3.9 gCO_2e MJ^{-1}.

3.2. Farming and co-product credits

LCAs for corn adopt a cradle-to-gate scope, including both on-farm emissions as well as those from the full supply chains associated with on-farm processes including fertilizer and chemical use, disturbance of farming soils, and fossil fuel and electrical energy use. LCAs published since 2010 estimate the CI for farming differ by as much as a factor of 2 and range from 16.0 to 34.4 gCO_2e MJ^{-1}. These estimates are based upon versions of the GREET model released from 2013 to 2020, as shown in table 1, and user-specified values for selected model parameters. We examined the farming components of these versions of GREET and the modeling scenarios to determine whether they meet our criteria for characterizing CI of corn ethanol as of 2020.

Examination of table 1 shows that the most recent estimate of farming CI from CARB is 6.4 gCO_2e MJ^{-1} lower than CARB's prior estimate and the largest difference among all CI estimates within a category other than LUC. Based on information from CARB, the decrease is primarily attributable to adoption of lower energy intensity for farming (6924 British thermal unit (Btu) $bushel^{-1}$ in the 2019 estimate compared to 9608 for the 2015 estimate) and lower fertilizer intensity (383 gallons of nitrogen fertilizer per bushel for 2019 compared to 423 gallons $bushel^{-1}$ for 2015) [70]. For its 2019 analysis, CARB adopted the default values that are in GREET1_2016 for these inputs [70]. According to the developers of GREET, the default values in GREET1_2016 are significant updates to earlier versions of GREET and are based upon new analyses of fertilizer intensity and farming energy data from the USDA Agricultural Resource Management Survey (ARMS) in 2010 and 2012 [71, 72]. Changes to these inputs will necessarily influence the overall CI results for farming because emissions of nitrous oxide (N_2O) from cycling of nitrogen fertilizer in corn fields, production of fertilizer, and direct energy use for fuel and electricity are the largest components of GHG emissions for growing and harvesting corn [40]. Based on this information, we determined the CARB

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Table 2. LUC analyses, models and outputs identified as meeting current best practice for LCA of corn ethanol.

Study	Year	Parameter	LUC value ($gCO_2e\ MJ^{-1}$)	Merits
USDA—2018—ICF	2018	dLUC	−1.9	• GTAP-BIO model calibrated with land transformation parameters • 2004 economic data year • Land-specific conversions • Acceptable YDEL
This analysis	2020	dLUC	−2.3	• GTAP-BIO model • 2004 economic data year • Land-specific conversions • Acceptable YDEL; based on empirical data • 2020 carbon calculator for land use change from biofuels production
USDA—2018—ICF	2013	iLUC	8.0	• GTAP-BIO model • 2004 economic data year • Land specific conversions • Acceptable YDEL • Calibrated output with empirical data that included land intensification
USDA—2018—ICF	2013	iLUC	1.3	• GTAP-BIO model • 2004 economic data year • Land-specific conversions • Acceptable YDEL • Calibrated output with empirical data that included land intensification
Taheripour	2017	LUC	8.7	• GTAP-BIO model • 2004 economic data year • Land-specific conversions • Acceptable YDEL; based on empirical data • Included land intensification parameter based on empirical data

ICF: ICF International.
dLUC: Domestic land use change.
iLUC: International land use change.
LUC: Total land use change.
GTAP-BIO: Global Trade Analysis Project-Biofuels.
$gCO_2e\ MJ^{-1}$: Gram carbon dioxide equivalent emission per megajoule [7, 33, 35].

Table 3. Farming parameters ranked by magnitude of impact on farming emissions.

		Emissions ($gCO_2e\ MJ^{-1}$)		
Category[a]	Farming model parameters	Default Ecoinvent	Adjusted Ecoinvent	GREET models
Small (1–5 $gCO_2e\ MJ^{-1}$)	Soil CO_2 from urea and lime	0[b]	0[b]	0[b]–2.8
	Irrigation energy	4.2	0.8	0[b]
	Harvest drying	16.7	2.0	0[b]
	Seed drying	4.5	3.3	0[b]
	On-farm fossil fuel use	3.3	3.3	−2.7
Large (5–15 $gCO_2e\ MJ^{-1}$)	Chemicals, supply chain	8.7	8.7	7.9–11.2
to Very large	N_2O emissions from soils	11.1	11.1	10.2–13.9
(>15 $gCO_2e\ MJ^{-1}$)	Co-product credit	—	—	−12.1 to −13.5[c]

[a] Categories are based on adjusted Ecoinvent and GREET models.
[b] 0 indicates that at least one source either omitted this model parameter or reported it as part of on-farm fossil fuel use.
[c] Included the default method use in GREET.
—Ecoinvent does not specify a co-product credit.
$gCO_2e\ MJ^{-1}$: Gram carbon dioxide equivalent emission per megajoule.
References [6, 7, 9, 10, 12–14, 42].

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2015 CI value for farming does not meet our best practice criteria and omitted it from further analysis. For similar reasons, we also omitted the EPA 2010 projection for farming emissions of 16 $gCO_2e\ MJ^{-1}$ projected to occur in 2022. And lastly, we omitted the USDA projection for farming emissions in 2022 of 21.3 $gCO_2e\ MJ^{-1}$ because it assumes numerous farming practice improvements that have yet been demonstrated to be widely adopted, including residue and tillage management, nutrient management, and cover crops.

To further evaluate the reliability of the farming results from these LCAs, we reviewed farming CI using a source of data independent of GREET, the Ecoinvent database of GHG emissions [42]. Table 3 shows the GREET and Ecoinvent farming model parameters ranked according to their contribution to the overall farming emissions. The major contributors to farming emissions are chemical supply chain, N_2O emissions from nitrogen fertilizer and nitrogen in crop biomass, and co-product credits.

Ecoinvent uses data from studies by the National Renewable Energy Lab (NREL) and USDA as inputs for modeling United States corn production [73–75]. Ecoinvent contains the central estimates of average quantities of input per unit of output from the NREL and USDA studies, with two exceptions: irrigation and on-farm drying of corn grain after harvest. We evaluated both of those model inputs using current data on average United States corn farming practices.

The Ecoinvent dataset reflected full use of irrigation, with a water use intensity of 0.24 m^3 water per kilogram (kg) of corn produced. However, not all United States farms use irrigation and national average water use intensity varies from year to year. We analyzed data from the USDA's ARMS database for all available survey years since 1996 [76]. The fraction of irrigated corn acres ranged from 11.5% to 15.7% across these years. We combined ARMS data on water inputs with data on annual corn production from the USDA Feed Grains database [77] to generate water use intensities of 0.03–0.06 $m^3\ kg^{-1}$ since 2000. We observed a declining trend during that period. The central estimate of this range, 0.045 $m^3\ kg^{-1}$, represents 20% of the irrigation intensity input (0.24 $m^3\ kg^{-1}$) used in Ecoinvent. Using our updated water use intensity estimate, we calculated the adjusted Ecoinvent CI contribution of irrigation to be 0.84 $gCO_2e\ MJ^{-1}$ instead of the original estimate of 4.2 $gCO_2e\ MJ^{-1}$.

Analogous to its treatment of irrigation, the Ecoinvent model assumed that 100% of corn grain required active fuel-based drying plus fans to lower grain moisture content from 39% at harvest to 14% at storage [42]. Farmers may also use passive drying (without fuel) in the field prior to harvest, which yields a lower starting moisture content. We compared the assumption of 39% moisture at harvest with historical data on corn moisture at harvest for the United States from 2010 to 2017 [78]. Annual averages in the United States ranged from 16.3% in 2010 to a high of 19.7% in 2013, with an 18% average over the entire period. A target moisture level of 14% for storage is also conservatively low; CARB and EPA cite storage moisture content levels of 15% and 15.5%, respectively [79, 80]. We adjusted the model to reflect the measured harvest moisture level of 18%, and a target moisture content of 15%, and retained the conservative assumption that 100% of farmers pursue active drying to achieve this moisture reduction. The result is an adjustment of drying's CI contribution from 16.7 $gCO_2e\ MJ^{-1}$ to 2 $gCO_2e\ MJ^{-1}$.

The Ecoinvent database is transparent at the unit process level, with over 1000 separately examinable processes contributing to the full supply chain for United States corn production. Upon examination of the models we detected that the supply chain for seed included a duplicate instance of seed drying; drying with the same amount of fuel use and emissions appeared both prior to, and then after, aggregation of the seeds at market. Removing this error caused a minor adjustment to the CI contribution of seed drying, from 4.54 $gCO_2e\ MJ^{-1}$ to 3.27 $gCO_2e\ MJ^{-1}$.

After updating data in Ecoinvent to reflect current United States corn farming practices in relation to irrigation, harvest drying, and seed drying, the CI for corn farming decreased by nearly 20 $gCO_2e\ MJ^{-1}$ (figure 3). The resulting adjusted Ecoinvent CI of 29.2 $gCO_2e\ MJ^{-1}$ was within ± 6 $gCO_2e\ MJ^{-1}$ of the recent GREET-based CIs (figure 4).

To account for farming co-product credits, we followed methods used in the well-to-wheel LCAs and determined a credible range and central estimate in accordance with the ISO 14044 standard for LCA [43].

We considered the emission co-product credit from DGS in our analysis, since DGS is a co-product of corn ethanol production and is sold to the animal feed market. The method selected for allocating co-product credits in LCAs can make a major difference on the CI estimates of co-product credits. A recent comparison found that co-product credits ranged from -8 to -24 $gCO_2e\ MJ^{-1}$ based on the allocation method used [6]. The ISO 14044 standard for LCAs recommends a hierarchy of methods for addressing co-product credits [43]. The preferred approach is the system expansion or displacement method followed by causal modeling, and then by allocation of process burdens among co-products based on parameters such as the co-product shares of process revenues.

Even when using the preferred method (i.e. the displacement method), there will still be some variability in co-product credits for the corn-based ethanol life cycle for two reasons; first, because the DGS can be used to displace a variety of products, whose corresponding footprints (and thus co-product credits to the ethanol system) vary considerably; and second because corn ethanol production also yields

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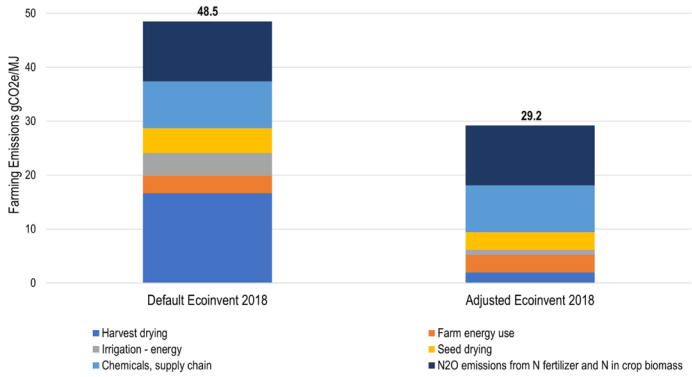


Figure 3. Comparison of farming emissions produced from the default and adjusted Ecoinvent 2018.

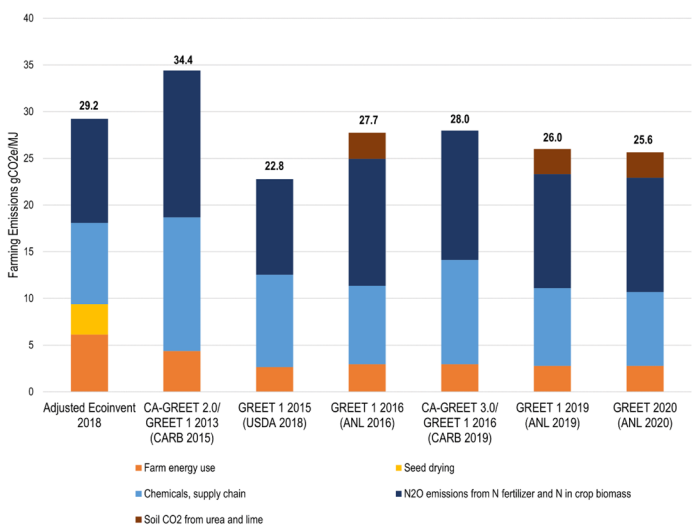


Figure 4. Comparison of sources of farming emissions across models produced from adjusted Ecoinvent and GREET.

co-products which can displace alternative production. DGS sold as animal feed can displace urea, and corn and soybean meal in different quantities depending on which type of livestock is being fed [9, 10, 12–14]. Ecoinvent data show the carbon footprint of soybean meal to be 0.07 kg CO_2e kg^{-1}, which is more than twice the value of 0.032 kg CO_2e kg^{-1} given for corn meal as energy feed [42]. In addition, corn ethanol production yields at least two additional byproducts: food grade CO_2, which can displace alternative production of food grade CO_2 [81]; and corn oil, which can substitute for other vegetable oils [82] or can replace fossil-fuel-based inputs in applications such as asphalt paving [83, 84].

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In this analysis, we conservatively focus on the displacement of feed products by the DGS co-product, and we follow the displacement ratios given in the GREET model for a mix of beef, dairy, swine, and poultry feed. ANL, CARB, and USDA rely upon the GREET displacement method ratios. EPA did not include information on their negative emissions associated with the DGS co-product. The negative emissions associated with displacement of feed products by the DGS co-product produced by ANL, CARB, and USDA using GREET range from −13.5 to −12.1 $gCO_2e\ MJ^{-1}$ (a maximum absolute difference of 1.3 $gCO_2e\ MJ^{-1}$), with a central estimate of −12.8 $gCO_2e\ MJ^{-1}$ (table 3). We adopt the value of −12.8 $gCO_2e\ MJ^{-1}$ which is based on the livestock-specific displacement ratios for soybean meal, corn and urea, for a mix of primarily beef and dairy feed, plus 13% swine and 6% poultry [9, 10, 12–14].

In summary, our review and analysis generated an overall range for farming emissions from 22.8 to 29.2 $gCO_2e\ MJ^{-1}$ with a central estimate of 26.0 $gCO_2e\ MJ^{-1}$, derived from recent GREET-based analyses and our independent analysis using data in Ecoinvent. We also considered the emission co-product credit from DGS in our analysis and generated a central estimate of −12.8 $gCO_2e\ MJ^{-1}$ with range of −13.5 to −12.1 $gCO_2e\ MJ^{-1}$ based on analyses from ANL, CARB, and USDA using GREET that conform with the ISO 14044 standard for addressing co-product credits in LCAs.

3.3. Ethanol production

LCAs for corn ethanol published since 2010 estimate the CI of corn ethanol production to range from 26.5 to 32.7 $gCO_2e\ MJ^{-1}$ (table 1). GHG emissions associated with biofuel production depend on the types of refining processes used to make ethanol from corn, the energy use intensity of those processes, and the sources and types of fuel used to provide the power.

There are two prominent refining processes for producing corn ethanol: dry milling and wet milling. In dry milling, the grain kernel is ground into meal which is followed by the starch hydrolysis and fermentation processes [45]. Dry milling refineries produce ethanol, DGS, and when incorporated into operations, the extraction of corn oil [82]. In contrast, the first step in wet milling is to soak grain kernel to separate the kernels from the hulls after which the kernels are further separated into fiber, gluten, and starch [85]. Wet milling refineries produce ethanol, and the resulting fiber and gluten are processed separately to produce feed products [85]. According to data from USDA, approximately 91% of United States refineries are dry milling plants and 9% are wet milling plants [86]. Wet milling provides higher ethanol fuel yields than dry milling [12–14], but requires more capital investment and is estimated to be over 75% more energy intensive [12–14, 20, 22, 87].

As shown in table S.4 in the supplemental materials, most of the analyses shown in table 1 assumed that 89% of refineries were dry mills which is consistent with the distribution of dry mill facilities in the U.S [86, 87]. Other models, such as CARB 2015, EPA 2010, and USDA 2018 (projected for 2022) estimated the CI for corn ethanol production assuming 100% dry milling. According to the models, electricity consumed from the grid accounts for approximately 10% of energy needs at the refineries with the remaining 90% powered by process fuels [2, 7, 9–14, 88, 89]. In these models, the primary process fuel is natural gas, with a share of 72.5% to 100% of process fuel energy use among refineries with coal accounting for the balance. Both natural gas and biomass are more energy efficient than coal; however, biomass is not widely used due to high fuel and capital costs [90].

The fuel production emissions produced by ANL, CARB, USDA, and EPA are consistent with one another with a maximum difference of approximately 6 $gCO_2e\ MJ^{-1}$. To evaluate those values further, we calculated production CI using data from the recently published ANL 2018 survey of 65 corn ethanol dry mill facilities located across 17 states in the United States and compared the result to the ethanol production values in table 1 [44]. The facilities surveyed reported average consumption of 24 310 Btu of natural gas per gallon of ethanol, 0.747 kilowatt-hour of electricity per gallon of ethanol, and no use of coal [44]. These rates correspond to 27.8 $gCO_2e\ MJ^{-1}$ of fuel production emissions at an average dry mill corn ethanol facility, a value that is in the lower end of the range of estimates produced by ANL, CARB, USDA, and EPA. The facilities in the survey sample may not be representative of the entire population of corn ethanol producers given that they are all dry mill facilities and none of them reported use of coal. Nonetheless, these recently available survey data corroborate the inputs on energy use intensity and energy type for the models that we reviewed. Based on these observations, we find a reasonable central estimate and credible range of CI for corn ethanol production of 29.6 $gCO_2e\ MJ^{-1}$ and 26.5–32.7 $gCO_2e\ MJ^{-1}$, respectively.

3.4. Other direct emission categories

The remaining GHG emission categories reviewed and updated were fuel and feedstock transport, tailpipe, and denaturant emissions. The fuel and feedstock transport category consists of emissions associated with the combustion of gasoline and diesel fuels during the transport of corn from farm to refinery and corn ethanol from refinery to retail station. The tailpipe category consists of emissions from the combustion of corn ethanol in transportation vehicles. Corn ethanol-based CO_2 emissions from tailpipes are assumed to be biogenic and offset by carbon uptake during new biomass growth [7]. Corn ethanol combustion also emits methane (CH_4), nitrous

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oxide (N_2O), and volatile organic compounds, which are included in modeling of corn ethanol tailpipe emissions.

CI values for fuel and feedstock transport and tailpipe emissions across the ANL, CARB, EPA, and USDA models average 3.4 and 0.5 $gCO_2e\ MJ^{-1}$, respectively (table 4). Together, these two categories represent about 6% of the overall CI score for most of the analyses. Although only a modest contributor to overall CI, the CI estimates vary by nearly three-fold for transport of feedstock and fuel (2.2–6.0 $gCO_2e\ MJ^{-1}$) and nine-fold for tailpipe emissions (0.09–0.83 $gCO_2e\ MJ^{-1}$). The variation across those ranges primarily reflects two factors: updates to the national input parameters and CA-specific versus national input parameters. We first address transport emissions and then tailpipe emissions.

Inspection of table 4 shows that feedstock and fuel transport emissions in the GREET models decreased by 15% to 25% with the release of GREET1_2016. The changes in GREET reflected a new analysis that accounted for closer proximity of corn farms to ethanol plants resulting from a five-fold increase in the number of production facilities in the Midwest corn-growing states and a shift from truck-dominated to rail-dominated delivery of ethanol [71]. The rapid expansion of ethanol in gasoline across the United States as of 2010 was the driving force for both the proximity effect and rail effect cited in the new analysis [72]. The difference between the CARB 2019 value of 4.1 $gCO_2e\ MJ^{-1}$ and the values from ANL of 2.2–2.7 $gCO_2e\ MJ^{-1}$ stem from adjustments made by CARB to fuel economy and cargo payload of trucks, tankers, and barges that convey ethanol [70]. In consideration of these updates to GREET, we adopt a credible range of 2.2–4.1 $gCO_2e\ MJ^{-1}$ and central value of 3.1 $gCO_2e\ MJ^{-1}$ for CI of fuel and feedstock transport.

Additional inspection of table 4 shows that CI for tailpipe emissions in the CARB 2015 and CARB 2019 LCAs are approximately five-fold lower than corresponding CI from ANL, EPA, and USDA. This difference reflects the lower emission standards in California compared to United States standards according to CARB [70]. The projection for 2022 made by EPA in 2010 is an outlier compared to the relatively consistent estimates issued by ANL since 2016, therefore we omitted the EPA value from further consideration. Given these results, we adopted a credible range of 0.09–0.55 $gCO_2e\ MJ^{-1}$ with a central value of 0.3 $gCO_2e\ MJ^{-1}$ for tailpipe emissions.

The final emission category that we assessed is the small amount of denaturant added to ethanol, approximately 2% by volume, to render it undrinkable [2, 92]. Denaturant was considered by CARB in its 2015 and 2019 LCAs but has yet to be included in LCAs from EPA, ANL, or USDA. CARB calculates the emissions associated with denaturant using a formula with CI inputs that include farming, co-product credit, fuel production, and fuel and feedstock transport. The calculated denaturant value is inversely related to the CI of the other emission categories. The California GREET 2.0 model estimated a denaturant CI of 0.55 $gCO_2e\ MJ^{-1}$ [9] and the CA-GREET 3.0 model estimated a denaturant value of 1.12 $gCO_2e\ MJ^{-1}$ [10]. We used the CA-GREET 3.0 approach to estimate CI for denaturant associated with the central estimate CI values from our analysis and computed a value of 2.0 $gCO_2e\ MJ^{-1}$. We used the minimum and maximum of these three values to define the credible range for denaturant CI as 0.55–2.0 $gCO_2e\ MJ^{-1}$ with a central estimate of 1.3 $gCO_2e\ MJ^{-1}$.

3.5. Carbon intensity of corn ethanol

Using the central estimates and ranges of LUC, farming, co-product credit, fuel production, fuel and feedstock transport, tailpipe, and denaturant emissions described in the preceding sections, we estimate the CI of corn ethanol to be 51.4 $gCO_2e\ MJ^{-1}$, with an overall range of 37.6–65.1 $gCO_2e\ MJ^{-1}$ (figure 5). Our findings for fuel and corn production and transportation are consistent with the decreasing and converging trend of GHG emission estimates that is apparent in the scientific literature (figure 1).

4. Discussion

We reviewed peer-reviewed publications and grey literature reports on well-to-wheel GHG LCAs and studies on specific components of LCAs that characterize CI for corn ethanol produced in the United States. ANL, CARB, USDA, and EPA are the four major organizations that produce LCAs for corn ethanol in the United States. Their estimates of corn ethanol CI decreased by approximately 50% over the prior 30 years although not uniformly. Estimates for GHG emissions from farming and production of ethanol fall within 20% of each other among the organizations. In addition, estimates of CI for farming and ethanol production that we produced from two independent sources of information corroborated the results from the four government organizations. However, treatment of LUC is less consistent among the organizations, with variability of approximately 70% among organizations. Our review indicates that estimates for CI of LUC from ANL and USDA are based upon more reliable methods and data than those from EPA and CARB. Overall those estimates produced by ANL and USDA of CI converge to a central best estimate of approximately 55 $gCO_2e\ MJ^{-1}$. Notably, some authors have generated lower and higher estimates of CI for corn ethanol than those evaluated here, but those assessments are for specific combinations of regions and technologies while our aim was to characterize emissions for the United States [93, 94].

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Table 4. Other direct emission modeling produced by ANL, CARB, USDA, and EPA.

	CARB 2015	ANL 2016	USDA 2018[a]	CARB 2019	ANL 2019	ANL 2020	EPA 2010 (2022)	USDA 2018 (2022)[a]
GREET model	CA-GREET 2.0 (GREET1_2013)	GREET1_2016	GREET1_2015	CA-GREET 3.0 (GREET1_2016)	GREET1_2019	GREET1_2020	GREET_1.89 c (2009)	GREET1_2015
				Fuel and feedstock transport				
Feedstock transport ($gCO_2e\ MJ^{-1}$)	2.06	1.49	1.86	1.5	1.55	1.2	—	1.16
Fuel transport ($gCO_2e\ MJ^{-1}$)	3.86	1.19	1.39	2.6	0.99	0.98	—	1.34
Feedstock and fuel transport ($gCO_2e\ MJ^{-1}$)	6.0	2.7	3.3	4.1	2.5	2.2	4.0	2.5
				Tailpipe				
CH_4 emissions ($gCO_2e\ MJ^{-1}$)	—	0.06	0.29	—	0.06	0.06	0.25	0.29
N_2O emissions ($gCO_2e\ MJ^{-1}$)	—	0.47	0.26	—	0.47	0.47	0.58	0.26
Tailpipe emissions ($gCO_2e\ MJ^{-1}$)	0	0.52	0.55	0.09	0.52	0.52	0.83	0.55

[a] USDA values include emissions associated with transport of fuel, feedstock, distillers grains, and corn oil.

$gCO_2e\ MJ^{-1}$: Gram carbon dioxide equivalent emission per megajoule.

CARB: California Air Resources Board.

USDA: United States Department of Agriculture.

EPA: United States Environmental Protection Agency.

CH_4: Methane.

N_2O: Nitrous oxide [7, 9, 10, 12–14, 91].

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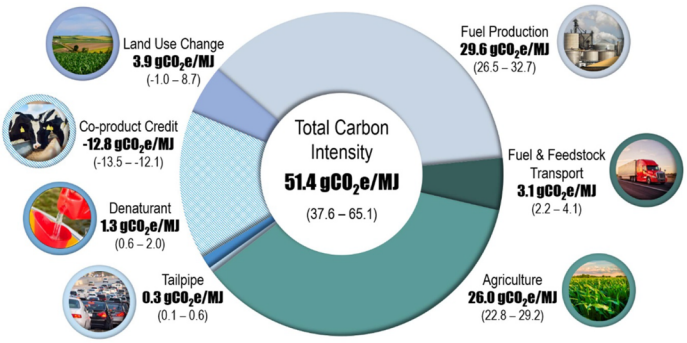


Figure 5. GHG emission categories and total CI of corn ethanol.

Modeled emissions from corn production and transport (including farming, feedstock transport, and co-product credit) decreased by approximately 14 $gCO_2e\ MJ^{-1}$ between 1990 and 2010 and stabilized in the last decade, with all recent estimates from CARB, ANL, USDA, and EPA in the range of 10.5–24.4 $gCO_2e\ MJ^{-1}$ (figure 1). The downward trend of corn production emissions is explained by improvements in farming practices and LCA methods. In the past few decades, corn yield has increased and fertilizer application per bushel of corn has decreased as a result of crop and nutrient management strategies, such as use of nitrogen inhibitors and precision agriculture [7, 76, 95]. According to USDA National Agriculture Statistics Service, the use of nitrogen fertilizer in grams per bushel of corn decreased by over 20% in the majority of 'United States Corn Belt' states (Illinois, Indiana, Iowa, Nebraska) between 2000 and 2018 [96]. Farm energy use decreased by approximately 8% on a per bushel basis from 2005 to 2010, a downward trend that is likely to have continued since 2010 [97]. The GREET model used to characterize farming emissions has also improved to quantitatively account for soil organic carbon, which tends to lower GHG emissions from corn farming [98]. Inclusion of co-product credit associated with corn oil as a biodiesel feedstock contributed to the downward trend of corn production and transport emissions as well [99].

GHG emissions associated with farming practices net of co-product credit constitute a relatively large share (26%) of the total CI for corn ethanol, therefore, additional improvements that reduce the cradle-to-gate footprint of corn production would improve the CI of corn ethanol further. Greater adoption of techniques for precision-based application of fertilizers offer significant economic as well as environmental benefits [100, 101]. The total cradle-to-farmgate CI for corn produced from states in the upper Midwest, which supply the bulk of corn to ethanol production, could be reduced in the region by up to 74% by adopting conservation tillage, reducing nitrogen fertilizer use, and implementing cover crops [102]. The implementation of land management practices such as cover crops and manure application can increase storage of organic carbon in soil [103]. Results of improved management practices for soil organic carbon (SOC) have been shown to depend on regionally variable factors including climate and soil characteristics, indicating the need and opportunity to pursue improvement management practices on a regionally tailored basis [103]. Biofuel policies that give farmers and corn ethanol producers incentives to adoptenvironmentally beneficial practices, are expected to result in wider use of those practices. In addition to reflecting current SOC practices, we recommend that future GREET models update inputs on energy sources used in corn production, since the current GREET model relies upon a 2015 USDA study that used farming data from 2010 [97]. One other recommendation arising from our review is that Ecoinvent update its dataset on United States corn production to reflect current average practice and more recent data, particularly for irrigation and grain drying.

Modeled emissions from ethanol production and transport decreased by approximately 27 $gCO_2e\ MJ^{-1}$ between 1990 and 2010 and stabilized in the last decade, with all recent estimates from CARB, ANL, USDA, and EPA falling within 28.5–34.1 $gCO_2e\ MJ^{-1}$ (figure 1). Models used to estimate fuel production emissions have also been updated to include more current inputs for electrical generation mix data and more accurate distribution of plant types. However, the latest fuel production models still use electrical generation mix datasets that are

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either dated or based on estimated projections; and assume the distribution of fuel types (e.g. natural gas, coal) and plant types (e.g. dry mill, wet mill) are either 100% dry mill and natural gas or have remained static since 2016 (table S.4). We recommend future studies validate the energy input and plant distribution data as they play a significant role in the determination of fuel production GHG emissions.

Since GHG emissions associated with producing ethanol account for 58% of the total CI for corn ethanol, additional production improvements related to co-products (DGS, CO_2, and corn oil) and alternative energy sources (biomass, biogas, and wind and solar energy) can play a significant role in reducing the overall CI of corn ethanol. Transitioning to 100% wet DGS can result in about -10 gCO_2e MJ^{-1}, due to savings in avoided energy associated with drying DGS [104]. Carbon dioxide, a co-product from the corn ethanol fermentation process, can be sequestered or captured and sold for uses elsewhere, such as in the beverage industry, and could result in up to -30 gCO_2e MJ^{-1} by avoiding CO_2 emissions being released or generated [81, 104]. Corn oil as a co-product can also lead to carbon credits if it displaces soy oil and if it is used as a pavement additive, which could extend the useful life of asphalt pavements [83, 84]. The use of alternative energy sources such as biomass, dairy or swine biogas, and solar or wind energy can result in up to approximately -20 gCO_2e M^{-1} [13], -65 gCO_2e MJ^{-1} [105], and -5 gCO_2e MJ^{-1} [79] CI credits, respectively. We estimated the maximum potential CI credit for biomass by substituting natural gas as the energy source used for fuel processing and drying of DGS in GREET [106]. We assumed biomass to be biogenic and its emissions as negligible, and did not consider the emissions associated with the processing and transport of biomass, nor the impact of corn stover as biomass on fertilizer use. We estimated the potential CI credit associated with biogas using 2019 LCFS pathways submitted to CARB for review [105], but did not consider logistical concerns regarding the supply and transport of sufficient biogas to refineries. We determined the CI potential of wind or solar power using CA-GREET [79], which includes wind and solar as emission free energy source options. The use of wind and solar power is not a feasible option to replace major energy sources such as natural gas but could be applied to specific refinery processes. We recommend continued research on the feasibility and impact of alternative co-product production processes, energy sources, and process fuels such as biomass, biogas, and wind and solar energy.

Modeled emissions from LUC decreased from 30.0 to 14.0 gCO_2e MJ^{-1} between 1990 and 2010 and have continued to decrease for LCAs from USDA and ANL (figure 1), due to modeling and land management improvements. Modeling improvements include refinements to GTAP-BIO, the field-leading agroeconomic model, use of appropriate YDEL values (0.175–0.35), and inclusion of land intensification. Data-driven improvements to the GTAP over the years include updated regional YDELs, land transformation elasticities, land intensification parameters, and yield improvements; and the inclusion of cropland pasture as a land type for the United States, Brazil, and Canada [35]. Models with these improvements have resulted in lower LUC values [7, 35]. For example, an adjustment to the land transformation parameter was made to account for the costliness associated with converting forest to cropland, relative to converting grassland [48, 107, 108]. The costs and resources associated with transforming forest to cropland, tend to deter farmers and result in the conversion of more feasible land types such as pasture. Including this realistic and logical observation in land transformation parameters results in a decreased likelihood of converting forest to cropland, ultimately lowering modeled LUC values [107]. ANL's dLUC model, CCLUB, has also been modified to include land management practices related to tillage and selection of soil depth, which influence SOC, and county-specific corn yield records of the modern agricultural period [33, 109]. Incorporating domestic land management practices that increase SOC and actual yield data play a role in lowering GHG emissions associated with LUC.

LUC emission estimates from ANL and USDA (including a prediction for 2022) from the last decade fall within our estimated range of -1.0–8.7 gCO_2e MJ^{-1}. Estimates from CARB (19.8 gCO_2e MJ^{-1}) and EPA (26.3 gCO_2e MJ^{-1} predicted for 2022) fall outside our range, resembling LUC values from LCAs prior to 2011 (figure 1), and are based on modeling approaches that do not represent current best practices. EPA used two different models that have limitations compared to GTAP-BIO: (a) FASOM, which focuses on dLUC and has not been widely adopted in LCAs for corn ethanol; and (b) FAPRI, which predicts non-specific changes in crop acres and requires external input of MODIS satellite data to assign land types, resulting in unreliable emission estimates associated with LUC [47]. CARB used the GTAP-BIO model, but three out of five YDELs used for modeling (0.05, 0.10, 0.35) [53] fall outside our determined best practice range (0.175–0.325), and may not be representative of actual corn crop yields in response to price change. CARB also used an agro-ecological zone emission factor (AEZ-EF) model, which tends to generate higher LUC emissions primarily because of its treatment of cropland pasture. Emission factors in LUC modeling are used to assign carbon stock changes and emissions associated with reported LUCs. AEZ-EF assumes emissions from converting cropland pasture to cropland release 50% of the emissions associated with converting pasture to cropland [110]. However, emissions associated with conversion of cropland pasture to cropland are likely

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to be lower due to periodic tilling since cropland pasture typically 'shifts back and forth between cropland and grassland depending on the net returns' [111]. Additional emission factor models used in LUC modeling are Woods Hole, Winrock International, and CCLUB [33, 112, 113]. In conducting our review, we did not identify a comprehensive analysis which focused on the evaluation and utility of different LUC emission factors. To improve the characterization of LUC, we recommend future studies conduct a thorough review of the various emissions factors to assess the validity of their assumptions and functions.

Compared to estimates in earlier LCAs, more recent analyses indicate that LUC accounts for a small percentage (7%) of the overall CI of corn ethanol. A limitation of the current approach for predicting LUC in LCAs is that the resulting GHG emissions are presented as a static number. In reality, changes in land use, such as clearing of forest for farmland used for biofuel, create a carbon debt that can be repaid over time as biofuel displaces petroleum or other fossil fuels [27, 114]. The payback period is determined by the magnitude of the original debt and the size of the carbon dividend from the biofuel. In this context, the LUC carbon impact is a dynamic property that starts out as a large source, and eventually becomes a net carbon sink. The original analyses based upon this 'debt-dividend' framework suggested a payback period for corn ethanol of 48–167 years based upon a relatively small biofuel dividend. The latest LUC estimates described here suggest that the current biofuel dividend has increased since those early analyses. Thus, we recommend future research to update earlier analyses of carbon debt and dividend for corn ethanol as the timescale for ethanol production to become a net carbon sink from land use considerations may be considerably shorter than prior estimates. The updated analyses should incorporate recent data on the carbon content of Midwest prairie land and the net CI of corn ethanol farming and production relative to gasoline refined from petroleum.

Our analysis reviewed LCAs and LCA components conducted by researchers that primarily relied upon the GREET model, or a version of the GREET model (e.g. CA-GREET). It is important to acknowledge other international modeling tools that are available for developing a GHG emissions profile for corn ethanol, such as GaBi [115], GHGenius [116], and RenovCalc [117]. A comparative analysis of international LCA modeling tools would strengthen understanding of the CI for corn ethanol. Additionally, our findings pertain to the impacts from current and modest increases in production and consumption of corn ethanol on a $gCO_2e\ MJ^{-1}$ basis. A full consequential analysis is necessary to assess the effect of major increases in production and consumption (e.g. increasing the percent volume of ethanol in gasoline from 10% to 20%). A full consequential analysis would address constraints in the production system including land use availability, farming efficiencies (e.g. yield elasticity), and resources (e.g. water), as well as additional indirect emissions from changes in rice crop and livestock production and management. EPA and USDA estimated those two categories to contribute between 1.5 and 2.7 $gCO_2e\ MJ^{-1}$ [2, 7]. As part of a sensitivity analysis, we determined that including those two emission categories would increase our CI estimate by approximately 4%.

LCAs should also expand upon the latest empirical analyses of land use over time and across regions to characterize potential indirect LUC more accurately [56, 68, 69, 118]. The most comprehensive study we drew upon was conducted by Babcock and Iqbal in 2014 [68]. We recommend additional empirical LUC studies to be conducted that rely on recent and updated data sources, such as the Food and Agriculture Organization of the United Nations [119] and satellite data.

Our analysis on the state of the science of GHG emissions associated with the well-to-wheel life cycle of corn ethanol yielded a CI central estimate of 51.4 $gCO_2e\ MJ^{-1}$. We compared our central estimate to the average CI of neat gasoline, which ranges from 93 to 101 $gCO_2e\ MJ^{-1}$ [2, 120, 121], with an average of approximately 96 $gCO_2e\ MJ^{-1}$. Relative to the average CI of conventional gasoline, our central estimate for corn ethanol is 46% lower. These results are relevant to policy and commerce because CI estimates generated from LCAs are used to make significant biofuel policy and market decisions on state, national, and international levels. We recommend that comparative analyses of the CI for transportation fuels clearly note the system boundaries of the respective analyses as our review demonstrates that the consequential components of a LCA can strongly influence the resulting CI estimates.

5. Conclusion

Assessments of GHG intensity for corn ethanol have decreased by approximately 50% over the prior 30 years and converged on a current central estimate value of approximately 55 $gCO_2e\ MJ^{-1}$ which is over 40% lower on an energy equivalent basis than gasoline produced from crude oil. The decrease in GHG intensity is attributable to updates in modeling systems and input data that reflect market-driven changes in farming practices that lowered the use of fertilizer and fossil fuel on a per bushel basis, more efficient use of natural gas and more recent electric generation mix data for energy consumed at ethanol refineries, and market-based analyses of LUC. Current estimates from organizations in the United States are primarily based upon the GREET modeling system and show that direct emissions associated with production of corn and ethanol from corn, including co-product credits for animal feed and corn oil, account for approximately 80% of the total CI. Two

independent sets of data relating to farming and ethanol production that we examined corroborate the results from GREET. Compared to farming and ethanol production, estimates of CI associated with LUC are more variable among recent LCAs, however, the most comprehensive evaluations indicate emissions are lower than 10 $gCO_2e\ MJ^{-1}$. Recent research indicates that market conditions that favor greater adoption of precision agriculture systems, retention of organic carbon in soil, and demand for co-products from ethanol production have the potential to reduce the CI of corn ethanol. Continued development and refinement of models to account for co-products, farming practices such as conservation of soil carbon, and direct and indirect LUC is expected to improve the accuracy of CI estimates in the future.

Data availability statement

The data that support the findings of this study are available upon reasonable request from the authors.

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Life Cycle Associates



GHG Emissions Reductions due to the RFS2-A 2020 update

LCA.6145.213.2021
February 11, 2021

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Terms and Abbreviations

ANL	Argonne National Laboratory
ARB	California Air Resources Board
Btu	British thermal unit
BD	Biodiesel
CI	Carbon Intensity
CNG	Compressed Natural Gas
CRF	Corn Replacement Feed
LNG	Liquefied Natural Gas
DGS	Distillers Grains with Solubles
DDGS	Dry Distillers Grains with Solubles
EPA	Environmental Protection Agency
EIA	Energy Information Agency
FAME	Fatty Acid Methyl Ester
GHG	Greenhouse gas
GREET	Greenhouse gas, Regulated Emissions and Energy Use in Transportation (Argonne National Laboratory's well-to-wheels model)
kWh	kiloWatt-hour
LCA	Life cycle assessment
LCFS	Low Carbon Fuel Standard
LHV	Lower heating value
MGY	Million gallons per year
MJ	Mega joule
mmBtu	Million Btu
RFS	Renewable Fuel Standard (U.S.)
NERD	Non-Ester Renewable Diesel
Tg	Terra gram (10^{12}g)
TTW	Tank-to-wheels
UCO	Used Cooking Oils
U.S.	United States
VOC	Volatile Organic Compound
WDGS	Wet Distillers Grains with Solubles
WTT	Well-to-tank
WTW	Well-to-wheels

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Executive Summary

The RFS2 has resulted in aggregate GHG emissions reductions from the use of biofuels, which exceed the original projections from the final Rule for the first 13 years of its implementation. The RFS2 has resulted in significant GHG reductions, with cumulative CO_2 savings of 980 million metric tonnes over the period of implementation to date. The GHG reductions are due to the greater than expected savings from ethanol and other biofuels. These emissions savings occur even though cellulosic biofuels have not met the RFS2 production targets. In addition, EPA underestimated the petroleum baseline in the Rule. Studies by Life Cycle Associates and the Carnegie Institute have shown that the GHG emissions from U.S. petroleum are higher than the EPA calculated in 2005 (Boland, 2014; Gordon, 2012, 2015). This study calculates the annual U.S. petroleum GHG intensity based on the changing trends in feedstock availability over time and determines the GHG savings calculated from the aggregate mix of renewable fuels. The GHG intensity for each category of ethanol plant and biodiesel feedstock is estimated for the resource mix over the past 13 years and combined to determine an aggregate estimate. Figure 1 shows the total emissions reductions from the RFS2 compared with the GHG reductions projected from the rule.

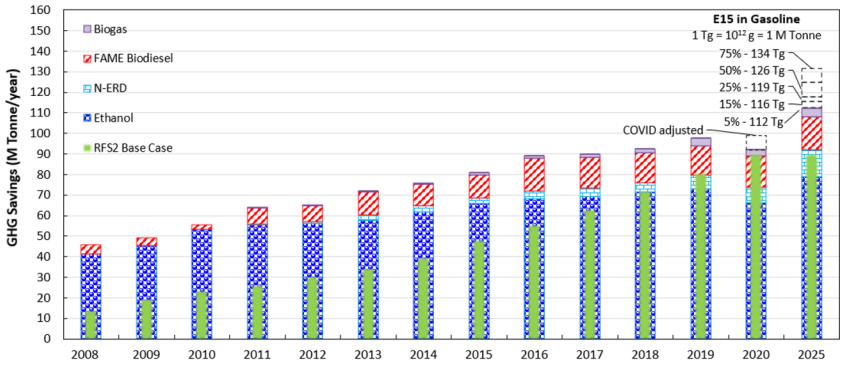


Figure 1. GHG Emissions Reductions due to the RFS2.

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1. Introduction

This study builds upon the 2014 Carbon Intensity of Marginal Petroleum and Corn Ethanol Fuels report and subsequent updates (Boland, 2014) (Boland 2015, Unnasch 2019)) released by Life Cycle Associates under contract to the Renewable Fuels Association. The Marginal Emissions report examined the trends in the greenhouse gas (GHG) emissions, termed Carbon Intensity (CI) of U.S. petroleum and corn ethanol transportation fuels. The CI is measured in grams of carbon dioxide emitted per megajoule of fuel (g CO_2 e/MJ). This work includes all renewable fuels sold under the RFS2 and their corresponding CI values.

The U.S. Renewable Fuel Standard (RFS2) requires the addition of 36 billion gallons of renewable transportation fuels to the U.S. slate by 2022. The RFS2 established mandatory GHG emission thresholds for renewable fuel categories based on reductions from an established 2005 petroleum baseline. Within the total volume requirement, RFS2 establishes separate annual volumes for cellulosic biofuels, biomass-based diesel, advanced biofuels, and renewable fuels. Figure 2 illustrates the RFS2 volume requirements per fuel category. To comply with the standard, obligated parties must sell their annual share (as calculated by EPA) within each category.

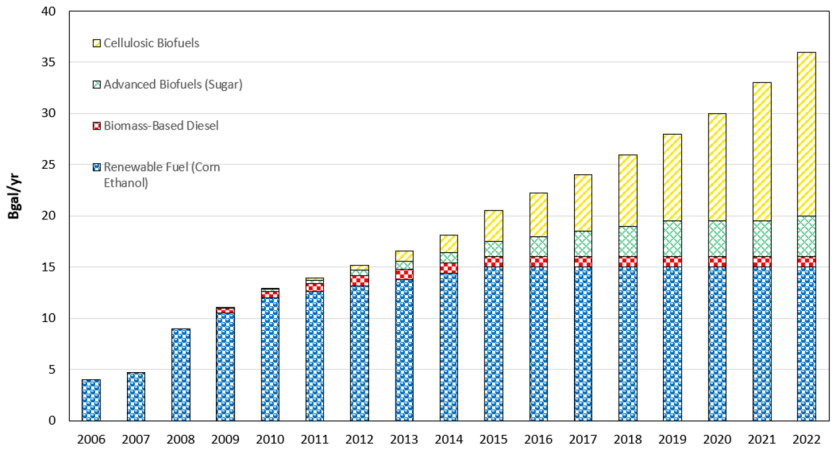


Figure 2. RFS2 renewable fuel volume requirements for the United States.

The 2005 petroleum baseline developed by EPA is based on the aggregate emissions from the production of petroleum fuels consumed in the U.S. during 2005. The methodology and assumptions for the petroleum baseline are contained in the EPA Regulatory Impact Analysis

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(EPA, 2010). The baseline remains constant throughout the statutory timeframe of the RFS2 (2005 to 2022). However, the mix of crude slates used to develop the baseline has changed since 2005, and the advent of new crude extraction and processing technologies has raised the aggregate CI of petroleum fuels above the 2005 baseline. Furthermore, the baseline refining emissions were underestimated and have since been revised in LCA models (ANL, 2014; El-houjeiri, 2012). The 2014 Marginal Emissions study (Boland, 2014) re-examines the mix of crude slates and U.S. consumption trends to develop the annual aggregate U.S. petroleum CI. The annual aggregate CI provides a more accurate estimate of the aggregate U.S. petroleum CI.

Figure 3 shows the weighted carbon intensities of petroleum fuels consumed in the U.S. alongside the EPA 2005 baseline. This revised estimate results in an aggregate petroleum CI that is higher than the 2005 EPA average gasoline baseline of 93.08 g CO_2 e/MJ. The median CI of aggregate U.S. petroleum gasoline is 96.8 g CO_2 e/MJ.

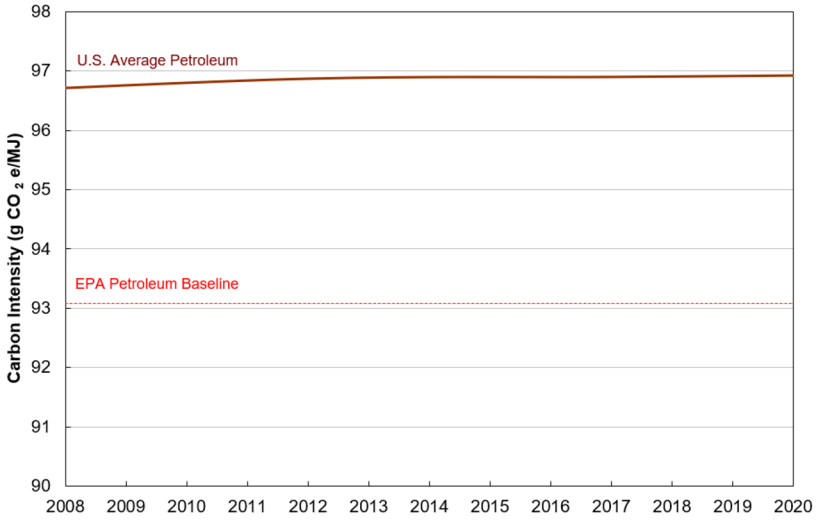


Figure 3. Weighted carbon intensity (g CO_2 e/MJ) of petroleum fuels consumed in the U.S.

1.1 RFS Renewable Fuel Categories, Production Volumes and RINS Generated

Table 1 shows the U.S. renewable fuel categories, the fuel type and the typical feedstocks used to produce each fuel. Also shown is the RIN D Code. The RIN code is the Renewable Identification Number (RIN), used to track fuel production and sales. Each type of renewable fuel generates a RIN when produced. Each D code applies to a specific RIN category.

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EPA reports fuels sold by D-code type, which are further categorized as shown in Table 1. EIA reports the types of feedstocks used in biodiesel production.[1] This study matched the fuel/feedstock combinations with fuel volumes. Some fuel categories achieve GHG reductions that are consistent with the 50% and 60% GHG reductions in the RFS2, while other fuels such as corn oil biodiesel achieve even lower GHG reductions than the RFS requirements. The CI for each feedstock and fuel is matching in the following analysis.

Table 1. U.S. Renewable Fuel Categories, Fuel Type, Feedstock Source and RIN D-Code

RIN code	Fuel Category	Fuel Type	Feedstock
D6	Renewable Fuel	Ethanol	Corn, Grain Sorghum
D6	Renewable Fuel	Biodiesel	Palm Oil
D6	Renewable Fuel	NERD[a] (EV 1.7)	Palm Oil
D5	Advanced Biofuel	Ethanol	Grain Sorghum, Sugarcane, Beverage Waste
D5	Advanced Biofuel	Biogas	Landfill, Wastewater Treatment
D5	Advanced Biofuel	NERD (EV 1.6)	Tallow, Used Cooking Oils, Soybean, Distillers' Corn & Sorghum Oil, Food Waste
D5	Advanced Biofuel	NERD (EV 1.7)	Tallow, Used Cooking Oils, Soybean, Distillers' corn & sorghum oil, Food waste
D5	Advanced Biofuel	Bio-Naphtha	Used Cooking Oils, Distillers' Corn & Sorghum Oil
D4	Biomass-Based Diesel	Biodiesel	Soybean, Canola/Rapeseed, Tallow, Distillers' Corn & Sorghum Oil
D4	Biomass-Based Diesel	NERD (EV 1.5)	Tallow, Soybean, Distillers' Corn & Sorghum Oil
D4	Biomass-Based Diesel	NERD (EV 1.6)	Tallow, Soybean, Distillers' Corn & Sorghum Oil
D4	Biomass-Based Diesel	NERD (EV 1.7)	Tallow, Soybean, Distillers' Corn & Sorghum Oil
D3	Cellulosic Biofuel	Ethanol	Corn Kernel Fiber, Biomass Stover
D3	Cellulosic Biofuel	RCNG	Landfill, Wastewater Treatment, Animal Waste
D3	Cellulosic Biofuel	RLNG	Landfill, Wastewater Treatment, Animal Waste
D3	Cellulosic Biofuel	Renewable Gasoline	Forest Waste, Crop Residue, Food Waste
D7	Cellulosic Diesel	NERD (EV 1.7)	Forest Waste, Crop Residue, Food Waste

[a]NERD = Non-Ester Renewable Diesel

Table 2 shows the U.S. renewable fuel volumes generated (million gallons of fuel) from 2008 - 2020 (i.e., the period of RFS2 implementation). The study also evaluates the effect of the RFS extended through 2020 with fuel volumes shown as indicated.

[1] EPA categorizes renewable diesel by equivalence value EV. The equivalence value represents the ratio of heating value of a biofuel to the heating value of a gallon of denatured ethanol. NERD EVs may vary with data submitted by different fuel developers with petitions to EPA.

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The GHG emissions for each category of fuel in Table 2 are calculated based on estimates of the composite carbon intensity (CI) for each of the fuels. The CI varies among all of the fuel technologies. Grain-based ethanol production uses a range of process fuels. Ethanol plants also produce distillers' grains, corn oil, and other food and feed products. Ethanol also is a higher-octane blending component which reduces the GHG emissions associated with crude oil refining.

Note that the RIN data is categorized by the Equivalence Value (EV) which corresponds to the different in energy content of diesel, naphtha, and jet fuel relative to ethanol which are typically associated with the production of non-ester renewable diesel (NERD) fuels as well as pyrolysis-based fuels. Biodiesel and NERD also use a range of feedstocks including vegetable oils and waste oils. The CI depends on the mix of these feedstocks.

Many sources of biogas generate RINs under the RFS including landfills as well as food waste and manure anaerobic digesters. The latter source of renewable natural gas (RNG) result in the avoidance of methane emissions, which further reduce GHG emissions. RNG is a feedstock for compressed natural gas (CNG) and liquefied natural gas (LNG) as well as a process fuel for some ethanol plants.

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Table 2. U.S. Renewable Fuel Volumes used in Transportation[2]

D-code	Fuel Type	Fuel Volumes (Million Gallons) [a]							
		2008	2010	2012	2014	2016	2018	2020[b]	2025
6	Ethanol	9,309	13,298	12,987	14,022	14,725	14,967	12,566	15,310
6	Biodiesel	0	0	1	53	113	0	0	0
6	NERD (EV 1.7)	0	0	0	151	166	107	76	80
5	Ethanol	530	16	603	90	61	102	185	650
5	Biogas	0	0	3	20	0	1	0	10
5	NERD (EV 1.6)	0	5	2	0	0	0	0	0
5	NERD (EV 1.7)	0	3	10	9	5	24	38	107
5	Bio-Naphtha	0	0	0	12	18	21	21	40
4	Biodiesel	678	343	1,056	1,436	2,194	2,030	1,998	2100
4	NERD (EV 1.5)	0	0	1	0	0	0	0	0
4	NERD (EV 1.6)	0	0	9	7	0	0	5	14
4	NERD (EV 1.7)	0	1	80	320	421	485	824	1,400
3	Ethanol	0	0	0	1	4	8	30	102
3	RCNG	0	0	0	15	117	222	344	443
3	RLNG	0	0	0	17	72	83	83	165
3	Renewable Gasoline	0	0	0	0	0	0	0	0
7	NERD (EV 1.7)	0	0	0	0	1	0	0	0
	Anhydrous Ethanol	9,642	13,047	13,318	13,831	14,494	14,776	12,525	15,741
	Denaturant	197	266	272	282	296	302	256	321
	FAME Biodiesel	678	343	1,057	1,501	2,325	2,052	2,019	2,140
	Total N-E RD	0	9	103	488	591	615	943	1,587
	Total Biogas	0	0	3	53	189	304	427	618
	Total	**10,517**	**13,665**	**14,753**	**16,155**	**17,895**	**18,049**	**16,169**	**20,407**

[a]Fuel volumes correspond to total net generation EPA RIN data divided by the fuel's equivalence factor.

[b]2020 is the assumed 12-month production total of biofuels based on the 9 months (January – September 2020) data available.

[2] Fuel volume is derived from the RIN generation data provided by EMTS.
https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions

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2. Land Use Change

The Land Use Change (LUC) reflects the net change in carbon stocks associated with expansion of crop production as well as indirect effects that are induced by the demand for feedstocks. LUC is an important, but controversial, element of a biofuel's life cycle impact, including the direct emissions associated with land conversion to agricultural fields and indirect emissions associated with economic impacts induced by the change to land use.

EPA, ARB and ANL have developed estimates for LUC estimates from biofuels production. These are summarized in Table 3. The development of LUC estimates is discussed in detail in the 2014 Marginal Emissions report (Boland, 2014). This analysis uses the best estimate for each biofuel category shown here to calculate the total emissions from the production of that biofuel.

Table 3. LUC Emissions Estimates from Biofuels

Policy	Corn EtOH	Sorghum Ethanol	Corn Stover	Sugarcane Ethanol	Soybean BD/RD	Canola BD/RD	Palm BD	Tallow BD/RD	Corn BD
					LUC (g CO_2e/MJ)				
2009 ARB	30	n/a	0	46	62	31	n/a	0	0
2010 EPA	28	13.1	-1.3	5.41	18.3	~15	48.2	0	0
2014 ARB	19.6	19.4	0	11.8	29.1	14.5	71.4	0	0
ANL/CCLUB	7.6	n/a	-1.1	n/a	n/a	n/a	n/a	0	0
Best Estimate	**7.4**	**7.6**	**-1.1**	**11.8**	**18.3**[a]	**14.5**	**48.2**	**0**	**0**[b]

[a] The ILUC associated with soy BD is consistent with the crop yield per acre. If ILUC per acre of corn is the same as ILUC per acre of soybeans, then ILUC for soybean-based BD or RD is about twice that of corn ethanol depending upon the displacement value of co-products from ethanol and soybean meal. The RFS and LCFS values for soybean and canola ILUC are used as a conservative assumption. The ILUC values for BD and RD should differ slightly depending on oil to fuel yield but these values are assumed invariant with biomass-based diesel type.

[b] Several approaches are available to assigning ILUC to ethanol and corn oil used for biodiesel production. The California ARB assigns all of the ILUC to ethanol and this approach is followed here.

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3. Carbon Intensity of Corn Ethanol and Biofuels production

Ethanol represents the largest volume of renewable fuel produced and consumed in the U.S. The Marginal Emissions report (Boland, 2014) developed aggregated weighted CI estimates for the corn ethanol produced in the U.S. based on the installed capacity shown in Table 4. The installed capacity is based on the production cases described in the EPA Regulatory Impact Analysis (EPA, 2010). The capacity per plant type (including projections for capacity expansions) was used to model the trend in corn ethanol production for RFS operational years of 2008 through to 2020.

Important developments in the mix of corn ethanol technology include the following:

- Rapid adoption of corn oil extraction for dry mill plants (95% by 2020)
- Introduction of corn fiber/kernel fiber/stover in 38 plants by 2020[3]
- Growth in the use of low CI biogas as process fuel
- Elimination of coal as fuel for dry mill ethanol plants

[3] While EPA has not approved corn fiber petitions, 38 pathways have been approved by the California ARB. This technology results in about a 3% increase in ethanol production capacity. The adoption rate should grow to 50 plants by 2025.

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Table 4. Corn Ethanol Production Capacity and Technology Aggregation

Plant Energy Source,	Capacity (Million Gallons per Year)						
Aggregated data[a,b]	**2008**	**2010**	**2012**	**2014**	**2016**	**2018**	**2020**
Wet Mill, Coal	1,888	1,877	1,893	1,474	1318	1162	745
Wet Mill, NG	107	328	473	854	1,100	1312	538
Dry Mill, Coal	54	36	19	15	0	0	0
Dry Mill, NG, DDGS[c]	2,919	2,366	1,812	1,613	1,600	500	522
Dry Mill, NG, WDGS[c]	1,442	1,178	913	903	900	230	183
Dry mill, corn oil DDGS	1,946	4,617	5,471	5,336	7,000	8,500	9,917
Dry mill, corn oil, WDGS	961	2,145	2,728	2,589	2,700	3,000	3,484
Dry Mill, CRF/green corn[d]	325	361	397	461	700	800	965
Dry Mill, Biogas/Biomass[e]	195	250	305	360	415	470	525
Corn Stover/Fiber[f]	0	0	0	0.73	4	10	55
Total Corn Ethanol	9,837	13,158	14,011	13,606	15,737	15,984	16,883

[a] EPA Regulatory Impact Analysis (RIA)for the final Transport Rule.(EPA, 2009)

[b] Projections in consultation with industry experts.

[c] The rapid adoption of corn or extraction in dry mill ethanol plants has penetrated most of the market due to the improvement in energy consumption, reduction in GHG emissions, and production of corn oil. Total corn oil biodiesel from EIA data corresponds to 0.13 lb of corn oil per gallon of ethanol, which is about half of the potential yield. The balance of corn oil is used as animal feed.

[d] Corn replacement feed (CRF) and low GHG corn farming can reduce GHG emissions by producing additional co-product credit and implementing low impact farming practices. The introduction of lower emission corn is projected based on projections from industry analysts. (ACE, 2018).

[e] 6 ethanol plants with biogas or biomass process fuel have approved LCFS pathways.

[f] 38 corn fiber/stover/kernel fiber ethanol pathways were approved under CA LCFS in 2020. Assume corn fiber ethanol is an additional 3% of plant capacity.

Other emission reduction strategies include the use of corn replacement feed from stover and improved farm practices. Practices such as no till and precision farming have reduced GHG emissions from corn and these technologies are expanding.

Table 5 shows the representative CI of ethanol produced at each type of production facility described in the RIA. The CI reflects the ILUC values from the latest GREET model (ANL 2020).

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Table 5. Carbon Intensity of Corn Ethanol

Corn Ethanol Production Type	Carbon Intensity (g CO_2 e/MJ) 2008 [a]	2015 [a]	2018 [a]	2020 [b]
Wet Mill, Coal	97.35	93.07	90.44	88.69
Wet Mill, NG	77.35	73.34	70.84	69.17
Dry Mill, Coal	67.61	63.38	N/A	N/A
Dry Mill, Average	64.27	56.04	54.55	54.11
Dry Mill, NG, DDGS	60.80	58.72	58.72	58.67
Dry Mill, NG, WDGS	54.38	48.78	48.78	49.88
Dry mill, corn oil DDGS	63.82	58.26	57.35	56.74
Dry mill, corn oil WDGS	54.92	49.79	49.79	49.78
Dry Mill NG, CRF	49.37	41.14	39.65	38.36
Dry Mill, Biomass/Biogas	38.00	34.14	30.00	28.15

[a] CI values from 2018 RFS Update (Unnasch 2018). CI of corn, electricity mix, and other life cycle factors have changed since then.

[b] Based on GREET1_2020 model. Data from GREET1_2020, provided energy inputs data to these calculations. Data from California LCFS pathways provide insight to corn fiber and biomass based – based pathways. GREET CCLUB estimates for ILUC included in this table.

Similar to ethanol, estimates for the production of bio- and renewable diesel were based on the feedstock use per fuel. The U.S. Energy Information Agency (EIA) provides inputs on the U.S. feedstock inputs into biodiesel production (EIA, 2015). The production volumes for modelled for the years 2008 through to 2020. The biodiesel feedstock production volumes are shown in Table 6.

Table 6. Feedstocks for U.S. Biodiesel Production

Product	2008	2010	2012	2014	2016	2018	2020
Total BD[a]	678	343	1,056	1,501	2,325	2,052	2,019
Canola oil	59	30	91	130	133	149	126
Corn oil	72	36	111	158	153	245	176
Palm oil	16	8	26	37	56	0	0
Soybean oil	360	182	561	797	1,619	1,212	1452
Tallow/Poultry	42	21	65	92	133	151	118
UCO	130	66	202	288	231	295	147

[a]Total BD volumes based on EPA-reported RINs. Split among oil types based on EIA data.

Similar estimates for the renewable diesel feedstocks were developed from the study of hydrogenation derived renewable diesel as a renewable fuel option in North America (Lambert, 2012). The biogas feedstocks are primarily landfill gas and wastewater treatment facility biogas. Biogas from anaerobic digestion of food waste and manure is also a source of biogas for CNG.

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Table 7 shows the volumetric weighted carbon intensity estimates (developed by weighting the production capacity with the CI for each technology/feedstock) for the each of the biofuel categories included in the RFS2. The table also shows the assumed minimum reduction threshold CI for the RFS2 for each fuel type.

More recent studies of petroleum GHG emissions also indicate that the estimates for the original 2005 petroleum baseline in fact somewhat higher (EIA, 2013; Elgowainy, 2014; Unnasch, 2009).

3.1 Fuel Impacts

In addition to displacing higher GHG fossil fuels, alternative fuels have several other impacts on the transportation system. High octane ethanol allows to produce less energy intense hydrocarbon blending components and results in higher efficiency in high octane fuels. Renewable diesel results in an ultra-low sulfur fuel with a high cetane number that helps refiners meeting fuel specifications. These factors contribute to the overall GHG benefit of renewable fuels.

Fuel Efficiency and Octane

Reformulated gasoline is produced by blending a hydrocarbon component for oxygenate blending (BOB) with ethanol. To produce regular gasoline with an Anti-Knock Index (AKI) (R+M)/2 octane of 87 an 84 octane BOB is blended with ethanol[4]. Refiners take advantage of ethanol's octane produces a BOB with few high-octane components. Typically, the reformer is operated at a lower severity or less blending from alkylation units contribute to the octane of gasoline (Hirshfeld, 2015; Kwasniewski, 2015). Kwasniewski presents the different scenarios on a GHG intensity basis with a difference of 1 g CO_2e/MJ of gasoline between E10 and zero ethanol blending cases. The result is consistent with the energy intensity in a paper from Argonne National Laboratory (Elgowainy, 2014)[5].

[4] The AKI for ethanol is 99.3 (Pearson, 2015) but its blending octane number at 10% level is 114.
[5] For example, alkylation units require 1.2 MJ input per MJ gasoline compared with 1.03 MJ/MJ for crude distillation. Displacing the higher energy intensity component with ethanol reduces the CI of the BOB.

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Table 7. Carbon Intensity Estimates of All Biofuels and RFS GHG Reduction Threshold (g CO_2e/MJ)

Fuel	Threshold	2008	2010	2012	2014	2016	2018	2020[a]	2025
Ethanol, D6	74.5	66.3	63.6	62.0	58.6	56.5	55.1	53.2	53.2
Biodiesel, D6	74.5	71.8	71.5	71.5	71.5	90.0	90.0	90.0	90.0
Non-Ester RD, D6	74.5	90.0	90.0	90.0	90.0	90.0	90.0	90.0	90.0
Ethanol, D5	46.5	41.9	42.1	42.1	42.2	39.6	39.6	38.0	38.0
Biogas, D5	46.5	25.6	24.4	24.4	23.8	23.3	23.3	21.0	21.0
Non-Ester RD (EV 1.6)	46.5	46.4	46.4	46.5	46.2	46.2	46.2	44.4	44.4
Non-Ester RD (EV 1.7)	46.5	46.4	46.4	46.5	46.2	45.9	45.9	43.8	43.8
Bio-Naphtha	46.5	46.4	46.4	46.5	46.2	45.9	45.9	33.1	33.1
Biodiesel	46.5	42.5	42.1	42.3	42.2	41.9	41.9	38.5	38.5
Non-Ester RD (EV 1.5)	46.5	35.0	35.0	35.0	35.0	35.0	35.0	34.8	34.8
Non-Ester RD (EV 1.6)	46.5	35.0	35.0	35.0	35.0	35.0	35.0	34.8	34.8
Non-Ester RD (EV 1.7) Soy/Tallow	46.5	35.0	35.0	35.0	35.0	35.0	35.0	34.8	34.8
Ethanol, Cellulosic	37.2	37.2	37.4	37.8	38.4	33.5	30.0	28.5	28.5
RCNG[b]	37.2	25.6	24.4	24.4	23.8	23.3	23.3	16.9	12.0
RLNG	37.2	29.6	28.3	28.3	27.6	27.0	27.0	20.6	15.7
Renewable Gasoline	37.2	28.0	27.0	27.0	26.6	26.1	26.1	22.6	22.6
Non-Ester RD, D3	37.2	28.0	27.0	27.0	26.6	26.1	26.1	26.1	26.1
US Electricity		204.6	182.5	182.5	170.3	159.9	159.9	159.9	159.9
Denaturant		81.0	81.0	81.0	81.0	81.0	81.0	81.0	81.0
Gasoline Blendstock	93.08	96.7	96.8	96.9	97.0	97.2	97.3	97.5	97.5
Diesel	93.08	98.7	98.8	98.8	99.0	99.2	99.3	99.9	99.9

[a]CI for Biodiesel (D6) and NERD (D6) is constant and rounded to equal 90 as CARB gives palm oil diesel the high CI equal to gasoline.

[b]CI for RCNG and RLNG is associated with the growing swine manure farms and digesters.

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The benefit of blending ethanol on the BOB produced at the oil refiners is examined for E10 and E15. For 87 octane fuels the E10 BOB results in a 1.0 g CO_2e/MJ reduction while a BOB formulated for E15 receives a 1.5 g CO_2e/MJ GHG reduction, which is proportional to the GHG savings from the ethanol in E10. In this case of E15 a lower octane BOB is possible to produce 87 AKI blended gasoline.

In the case of E15 that results in a higher octane, the BOB is assigned the same 1 g CO_2e/MJ savings as the E10 BOB as it is the same refined product. The balance of E15 and E85 are estimated to result in higher octane fuels the same gasoline BOB used for E10 blending. All of the BOB for E10 or higher-octane blends is assigned 1 g CO_2e/MJ GHG reduction due to the effect on oil refineries. A 5% increase in ethanol will result in an extra octane point while E85 can have an octane number close to 93.

Several studies examine the effect of octane on fuel economy. Higher octane allows for an advance in ignition timing and higher turbocharger boost in engines with knock sensors. A 1% to 3% increase in energy economy is consistent with data from the EPA fuel economy guide where fuel consumption is reported or both E10 and E85 vehicles. The improvement in fuel economy from engine testing studies also indicates an efficiency improvement on the order of 1% for a 2-point increase in octane (Shuai, 2013; Stradling, 2015; Leone, 2017). Energy-economy ratio values of 1.005 and 1.02 were estimated for E15 and E85 respectively. The EER represents the energy economy of gasoline (E10) relative to the alternative fuel.

3.2 GHG Calculation Methods

GHG emissions were calculated based on the displacement of petroleum fuels. The aggregate mix of biofuels as well as crude oil resources provided the basis for GHG calculations. Displaced gasoline and diesel are calculated for each category of biofuel. In the case of ethanol, the effect on octane blending is also calculated. The net change in GHG emissions corresponds to the aggregation of each component fuel in the RFS. GHG emissions were calculated for each fuel category in equations 1, 2, and 3.

GHG from alternative fuel = Fuel volume × LHV × CI for each fuel (1)
The denaturant component of ethanol is calculated separately along with the biofuels

Displaced emissions correspond to severe effects including:

Alternative fuel volume × EER × LHV × CI for each fuel (2)

In the case of E15, E85, and CNG the EER values in this study are 1.005, 1.02, and 0.9 respectively

BOB volume associated with achieving 87 octane fuel × LHV × 1 g CO_2e/MJ savings (3)

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For biodiesel and renewable diesel, the petroleum baseline fuel is diesel. Biogas displaces a mix of gasoline and diesel with a more conservative EER of 0.9 assumed for diesel displacement.

Net GHG emissions are calculated based on the CI of the renewable fuel minus the displaced fuel. In the case of ethanol, additional octane blending benefits are included as part of the impact. Table 8 provides an example for 1 billion gallons of ethanol with two CI value deployed either as E10 or E15. In the case of E10, 1 billion gallons corresponds to 81,224 TJ of energy and displaces the same energy in the BOB. For the E15 example here, half the ethanol displaces a proportional quantity of BOB. The other half of the E15 (500 million gallons) results in an EER of 1.005 and displaces more BOB. The effect on octane blending is also shown for each fuel volume.

Table 8. Carbon Intensity Estimates of All Biofuels plus EPA Minimum Threshold

	E10 87 Octane		**E15 87 Octane**		**E15 88 Octane**	
	TJ	**Gg GHG**	**TJ**	**Gg GHG**	**TJ**	**Gg GHG**
Energy Inputs and Emissions[a]						
10% Wet Mill Coal Ethanol	8,122	720	4,061	360	4,061	360
90% Dry Mill WDGS Ethanol	73,101	3,639	36,551	1,819	36,551	1,819
Total Ethanol	81,224	4,359	40,612	2,180	40,612	2,180
EER	1		1		1.005	
Displaced BOB	-81,224	-7,862	-40,612	-3,931	-42,515	-4,115
Total BOB	1,080,000		340,000		340,000	
Refinery Octane	1,080,000	-1,080	340,000	-510	226,667	-227
Net Emissions		-4,583		-2,262		-2,162
Fuel Volume						
Ethanol (B gal)	1		0.5[b]		0.5[b]	
RFG (B gal)	10		3.33		3.33	

[a]CI of Wet Mill Coal, Dry Mill WDGS, and BOB are 88, 49, and 96.8 g CO_2e/MJ respectively. Octane blending effect of E10 and E15 are 1 and 1.5 g CO_2e/MJ respectively.
[b] 50% of the billion gallons of ethanol in the E10 example are calculated for an 87 octane and 88 octane strategy. In the 88 octane calculation the BOB receives a lower octane blending credit while displacing more BOB.

3.3 Avoided GHG Emissions

The avoided GHG emissions are calculated from the reduction in CI from the revised petroleum baseline, as developed by Boland et al. (Boland, 2014). Figure 4 shows the total CO_2 savings, in million metric tonnes per year (Million tonne/yr) from the inclusion of ethanol in the RFS2.

Key changes in fuel volume include a growth in the production capacity of renewable diesel and biogas from animal waste.

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The effect of different levels of E15 in 2025 are also examined using the approach outline previously assuming that 50% is blended at 87 octane and the balance results in higher octane fuel. 51% E15 in a gasoline pool of 138 billion gallons per year could be achieved with the current corn ethanol capacity in the U.S. of 17.4[6] billion gallons per year[7]. Note that the scenario for E15 shown here for 2025 uses more than the 15 billion gallons of D6 ethanol required under the RFS2. E15 results in additional GHG reductions because more ethanol is consumed as fuel and it enables the production of a lower octane BOB.

Figure 5 shows the CO_2 saving from all other biofuels. Since ethanol is thus far the major component of the RFS2, the majority of CO_2 savings are due to the ethanol fuels. Figure 6 shows the total CO_2 reductions of the RFS2 based on the analysis presented here. The base RFS assumptions are also shown in the graph, where the biofuels meet the minimum CI threshold mandated in the RIA (EPA, 2009) and as shown in Table 7. The RFS2 has resulted in the cumulative CO_2 savings of 980 million metric tonnes over the period of implementation (till 2020). The CO_2 savings as calculated from the minimum CI threshold base assumptions outlined in the RIA (EPA, 2009) results in the cumulative CO_2 savings of 593 million metric tonnes of CO_2.

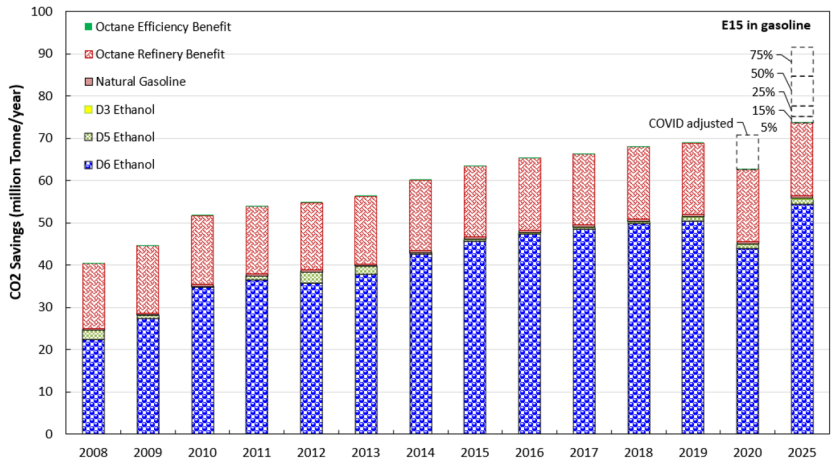


Figure 4. GHG Savings from Ethanol

[6] US fuel ethanol production capacity for the year 2020.
https://www.eia.gov/petroleum/ethanolcapacity/index.php
[7] EIA projects 9 million bbl/d of gasoline consumption in 2022 or 138 billion gallons per year. 29% of ethanol as E15 could be achieved with U.S. ethanol production capacity for 150 billion gallons per year of gasoline consumption.

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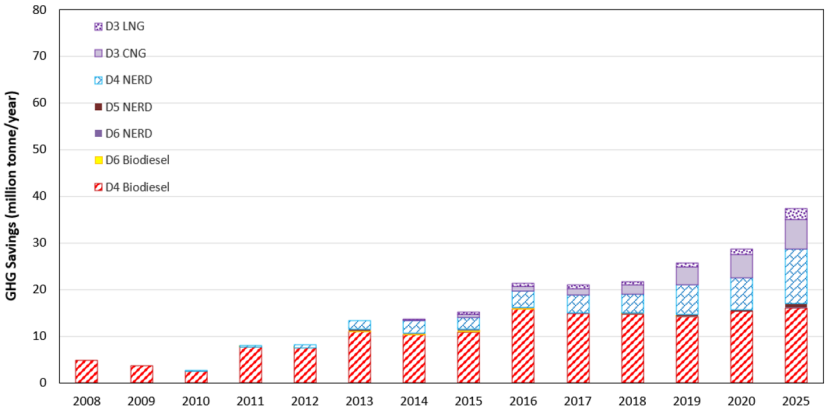


Figure 5. GHG Savings from Other RFS2 Biofuels (Excluding Ethanol).

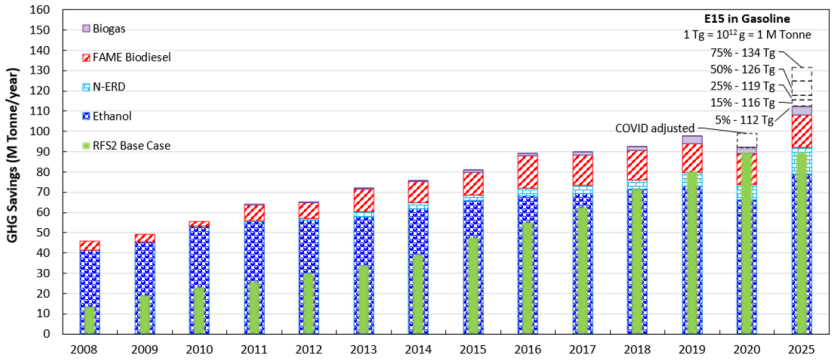


Figure 6. GHG Savings from the RFS2 Program

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4. Conclusions

The RFS2 has resulted in GHG emissions reductions, which exceed the original projections from the 2010 final Rule. The increased GHG reductions are due to the following:

1. Corn ethanol has adopted technology improvements, which results in greater than the 20% reduction in GHG emissions originally required under the RFS.
2. Petroleum GHG emissions are higher than the baseline projected by EPA.
3. The mix of other renewable fuels has also contributed to additional GHG reductions even though cellulosic ethanol targets in the original rule have not been met.

Biofuels have achieved and exceeded the GHG reductions estimated by EPA. The reductions are greater than the categories within the RFS2 because technology improvements have resulted in reductions in energy use and the RFS categories characterize typical renewable fuels. These categories were not intended to represent the weighted GHG reductions of all fuels produced under the rule.

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The greenhouse gas benefits of corn ethanol – assessing recent evidence

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ABSTRACT

In 2010, the U.S. Environmental Protection Agency (EPA) released a life-cycle analysis of the greenhouse gas (GHG) emissions associated with the production and combustion of corn ethanol. EPA projected that by 2022, the emissions profile of corn ethanol from a new refinery would be 21% lower than that of an energy equivalent quantity of gasoline. Since 2010, the 21% value has dominated policy discussions and federal regulations related to corn ethanol as a renewable fuel and a GHG mitigation option. It is now 2018 and new data, scientific studies, technical reports, and other information allow us to examine the emissions pathway corn-ethanol has actually followed since 2010. Using this information, we assess corn ethanol's current GHG profile at 39–43% lower than gasoline. We also develop two projected emissions scenarios for corn ethanol in 2022. These scenarios highlight opportunities to produce ethanol with emissions that are 47.0–70.0% lower than gasoline. Many countries are now developing or revising renewable energy policies. Typically, biofuel substitutes for gasoline are required to reduce GHG emissions by more than 21%. Our results could help position U.S. corn ethanol to compete in these new and growing markets.

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Introduction

Between 2004 and 2014, US ethanol production, virtually all from cornstarch, increased from 12.87 to 54.13 billion liters per year. This increase was driven by two pieces of legislation that mandated the nation's supply of transportation fuel, in aggregate, must contain specific amounts of biofuels. The Energy Policy Act of 2005 established the Renewable Fuel Standard (RFS), which included a schedule of required biofuel use that started at 15.14 billion liters in 2006 and rose to 28.39 billion liters by 2012. The Energy Independence and Security Act of 2007 replaced the RFS with the Revised Renewable Fuel Standard (RFS2). The RFS2 included a new schedule of required biofuel use that began at 34.07 billion liters in 2008 and ramps up to 136.26 billion liters by 2022. Corn ethanol's mandate started at 34.07 billion liters in 2008, increased to 56.78 billion liters in 2015, and remains at that level through 2022.

A key objective of the RFS2 is to reduce greenhouse gas (GHG) emissions associated with transportation fuels. Currently, the only cost-effective biofuel substitute for gasoline is ethanol. Under the RFS2, ethanol can qualify as a conventional, advanced, or cellulosic biofuel. Conventional biofuel is defined as ethanol made from cornstarch. To be a renewable fuel, corn ethanol produced in refineries that began construction on or after 19 December 2007 must have life-cycle GHG emissions at least 20% lower than an energy-equivalent quantity of average gasoline in 2005.[1] Corn ethanol produced in refineries in place or under construction on that date is grandfathered in as conventional biofuel regardless of its GHG profile. Ethanol made from cellulose, hemi-cellulose, lignin, sugar, starch (not from corn), and various types of waste biomass that has life-cycle GHG emissions at least 50% lower than those of gasoline qualify as 'advanced biofuels'. Additionally, ethanol made from cellulose, hemi-cellulose, or lignin that has a GHG profile at least 60% lower than that of gasoline qualifies as 'cellulosic biofuel'. Over time, advanced and cellulosic biofuels receive increasing shares of the annual renewable fuel mandate.

Quantifying the GHG profile of corn ethanol has been contentious since Searchinger et al. [2] concluded that the emissions associated with its production and combustion exceeded the emissions associated with producing and combusting an energy-equivalent quantity of gasoline. The authors argued that using billions of kilograms of US corn to produce ethanol reduces supplies of, and increases prices for, corn and other commodities in domestic and world food and feed markets. Farmers in the United States and elsewhere respond by bringing new land into production. These land-use changes (LUC) are related to ethanol production because the new land is used to grow more corn and to replace some of the decreased production of other commodities that occurs when US farmers allocate more existing cropland to corn.

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Searchinger et al. [2] argued that including emissions related to LUC, particularly international LUC (iLUC), results in corn ethanol having a higher GHG profile than gasoline.

The RFS2 directed the US Environmental Protection Agency (EPA) to do a full GHG life-cycle analysis (LCA) for corn ethanol and to include both direct and significant indirect sources of emissions. EPA designated iLUC, international livestock, international rice methane, and international farm inputs as significant indirect sources. The LCA was released in the 2010 Regulatory Impact Analysis (RIA) of the RFS2 [1]. It included projections through 2022 of the GHG emissions associated with 11 source categories that, collectively, capture the full range of direct and indirect GHG emissions associated with the production and combustion of corn ethanol. The EPA concluded that in 2022, the emissions profile of a unit of corn ethanol from a new natural gas-powered refinery would be 21% lower than the emissions profile of an energy-equivalent quantity of 'average' gasoline in 2005.

Since 2010, the RIA LCA for corn ethanol has dominated policy discussions and federal regulations related to ethanol as a renewable fuel and a GHG mitigation option. During this time, a large body of new data, scientific studies, technical reports, and other information has become available collectively showing that the emissions pathway corn ethanol has followed since 2010 is much lower than that projected in the RIA. Our objective is to assess corn ethanol's current GHG profile in light of this new information. This work is timely as many countries (e.g. Colombia, Japan, Brazil, Canada and the European Union) are developing renewable energy policies that require biofuel substitutes for gasoline to reduce GHG emissions by more than 21%. Our results could help position US corn ethanol to compete in these new and growing markets.

We also develop two projected emissions profiles for corn ethanol in 2022. A business-as-usual (BAU) scenario assumes a continuation through 2022 of several trends that have been reducing corn ethanol's GHG profile over time (e.g. refineries switching from coal to natural gas as a process fuel). A high efficiency-high conservation (HEHC) scenario assumes a proactive approach by refineries to lower the GHG profile of ethanol. In addition to the BAU trends, this scenario assumes refineries adopt specific GHG emissions-reducing technologies and practices. The results of this scenario could apply to a refinery, a set of refineries, or the industry as a whole.

Methods

In 2010, the RIA LCA was the most comprehensive assessment of corn ethanol's GHG profile. EPA developed three scenarios to assess the impacts of the RFS2's ethanol mandate. A 'reference case' considered the situation with no RFS2. Projected volumes in 2022 of corn ethanol, soybean biodiesel, and cellulosic ethanol (46.56, 0.38, and 0.0 billion liters, respectively) were taken from the Energy Information Agency's (EIA) Annual Energy Outlook for 2007 [3]. A 'control case' included the renewable fuel volumes mandated by the RFS2 by 2022. For corn ethanol, soybean biodiesel, and cellulosic ethanol these are, respectively, 56.78, 2.27, and 48.45 billion liters. A 'corn ethanol only case' set corn ethanol at its reference case volume and soybean diesel and cellulosic ethanol at their 2022 RFS2 levels. Comparing the control and corn ethanol only cases isolated the impacts of the corn ethanol mandate.

The RIA LCA is the starting point for our analysis. For each of the 11 emissions categories we: (1) review the RIA projection; (2) describe relevant new information that has become available since 2010; and (3) quantify a new emissions value based on the new information.[2] For some categories, no substantive new information has appeared since 2010. In these cases, we apply, as appropriate, new emissions coefficients and global warming potentials (GWPs) to the RIA values. For source categories where new information indicates that emissions have not developed as projected in the RIA, we use a variety of methods to derive new emissions values. In some cases, our methods differ from those used in the RIA. This is particularly true for categories where emissions reflect changes in domestic and international land use.

Most of the new data, emission factors (EFs), and global warming potentials we use in this analysis have become available from 2010 to 2015. Most of the studies we draw on have publication dates between 2013 and 2015. This means our current GHG profile does not reflect a specific year but rather a composite year representative of the mid-2010s. Finally, in developing updated emissions values we use a variety of metrics. To aggregate emissions across categories and facilitate comparisons with RIA emissions values, we convert the total emissions for each category to the RIA metric, grams of CO_2 equivalent per million Btu (g CO_2e/MMBtu).[3]

Results

Domestic farm inputs and fertilizer N_2O

This category includes emissions related to the on-farm use of fertilizers, other chemicals, fossil fuels, and purchased electricity. We also include here an emissions credit that accounts for emissions reductions associated with substituting ethanol co-products for grains in livestock diets.

EPA used the Forestry and Agricultural Sector Optimization Model (FASOM) to assess the US farm sector impacts of the RFS2 on production, land use, and input use. FASOM is a dynamic partial equilibrium economic model that disaggregates US agriculture into 11 market regions and 63 sub-regions [4]. The model includes over 2000 crop, livestock, and biofuel production systems. In FASOM simulations, lands shift between commodities in response to new policy or market conditions and the model tracks changes, by commodity, in acres, production and input use (including nitrogen, phosphorus, potash, herbicides, pesticides, diesel, gasoline, natural gas, and electricity). Life-cycle EFs for fuels and fertilizers are from Argonne National Laboratory (ANL)'s GREET 2009 model. EFs for fertilizer-related N_2O are from Colorado State University's DAYCENT model. Comparing simulation results for the 'control' and 'corn only' cases, the RIA emissions value for this category was 10,313 g CO_2e/MMBtu [1].

The RIA projected 19.66 million additional tonnes of corn would be needed by 2015 to produce the 9.84 billion liters of ethanol required to meet the RFS2's 56.78 billion liter cap. Since the overall mandate was 55.98 billion liters

Table 1. Ethanol production market breakdown and animal feed displacement by ethanol plant type.

Ethanol plant type	Ethanol market share (%)	Total displaced animal feed (g/L of ethanol)				Co-product credit	
		Corn	Soybean meal	Urea	Soy oil	g CO_2e/L ethanol	g CO_2e/MMBtu
Dry mill w/o corn oil extraction	17.7	527	207	15.3	–	−262	−12,981
Dry mill w/corn oil extraction	70.9	504	198	14.6	–	−250	−12,417
Wet mill	11.4	857	–	13.1	117	−291	−14,449
Weighted average		–	–	–	–	−257	−12,749

in 2014 and 56.78 billion liters thereafter, we use the RIA corn projection as the basis for assessing the current emissions for this source category. Dividing 19.66 by the average US per-hectare corn yield in 2015 of 10.57 tonnes, we estimate the RFS2 corn ethanol mandate would require US farms to increase corn area by 1.86 million hectares.[4] We allocate these acres regionally based on corn acreage data in the United States Department of Agriculture's (USDA) 2010 Agricultural Resource Management Survey (ARMS) [6].

For inputs, we consider changes in farm sector use of nitrogen (N), phosphorus (P), and potassium (K); composites for herbicides, insecticides, and fungicides; and diesel fuel. We get chemical application rates for corn, nationally and by region, from the 2010 ARMS [6].[5] For fungicide, ARMS data identify application rates for the Corn Belt and the nation. For non-Corn Belt regions, we use the national rate. Based on University of Tennessee farm budgets for 2015 [7], we set diesel fuel use at 72.36 L/ha under conventional tillage. To account for hectares on which a given chemical is not applied, we calculate an effective application rate by multiplying the ARMS regional application rate by the percentage of hectares in each region that apply that chemical [6].[6] Our region-weighted national average effective application rates for nitrogen, phosphorus, potassium, herbicides insecticides, and fungicides are 155.27, 53.55, 54.34, 2.36, 0.02, and 0.01 kg/ha, respectively. Regional effective application rates are available in Rosenfeld et al. [5].

From the regional acreage changes and effective application rates, we obtain changes in chemical and fuel use by US agriculture in response to the RFS2 corn ethanol mandate. Multiplying these changes by EFs from several sources, we get corresponding emissions estimates. Energy-related emissions also occur in the manufacture and transport of chemicals and fuel inputs. EFs reflecting these 'upstream' activities for nitrogen, phosphorus, potassium, and insecticides are obtained from the GREET 2015 model [8]. From GREET 2015 we also obtain EFs for diesel fuel covering both upstream activities and on-site combustion. EFs covering upstream activities for herbicides and fungicides come from the ecoinvent v2 database [9]. For nitrogen fertilizer applications, N_2O is emitted directly to the atmosphere from cultivated soils, and indirectly at other locations when N is transported offsite through volatilization, leaching, and runoff. EFs for these direct and indirect N_2O emissions follow IPCC guidance per kilogram of N fertilizer applied [10].

We assess emissions related to fertilizers, herbicides and pesticides and fuel at 10,815, 8382, and 2617 g CO_2e/MMBtu, respectively. Summing these values, we estimate the total emissions-related domestic use of farm chemicals and fuel at 21,814 g CO_2e/MMBtu. Our approach differs from the RIA's, which simultaneously accounts for the substitution of ethanol co-products for grain in animal feed markets, resulting in a reduction in additional corn production (and therefore hectares) required to meet the RFS2 ethanol mandate. Our use of regional effective application rates means our emissions estimates apply to 'representative' incremental regional acres.[7] Hence, we still need to account for the co-product emissions credit.

Animal feed co-products from ethanol production include distiller grains and solubles (DGS) from dry milling and corn gluten meal and corn gluten feed (CGM and CGF) from wet milling. We use the 'displacement method' to assess the co-product credit. In this approach, all energy and emissions associated with separating solids from the ethanol stream, drying the solids, and transporting the finished feeds to the point of final sale are allocated to the ethanol pathway. The pathway then receives a credit equal to the emissions that would have occurred if the displaced feed grain had been produced. GREET 2015 includes values for displaced animal feed per unit of ethanol by milling process. Table 1 shows these values and the co-product emissions credits per liter of ethanol and per MMBtu.

Summing the farm inputs emissions (+21,814 g CO_2e/MMBtu) and the weighted average co-product credit (−12,749 g CO_2e/MMBtu) gives a total emissions value of 9065 g CO_2e/MMBtu. This is slightly lower than the RIA value and largely reflects the lower GWP for N_2O from the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4). EPA used GWPs from the IPCC's Second Assessment Report (AR2).

Domestic land-use change

Domestic LUC includes: (1) direct land-related emissions associated with shifting cropland and land from other uses into corn production; and (2) indirect emissions related to bringing new lands into production to replace some of the decreases in output of non-corn commodities that occur when farmers allocate more existing cropland to corn. For the RIA, EPA used FASOM to estimate domestic LUC and the associated emissions. FASOM tracks carbon stored in trees, understory, and litter within forests and plantations of woody energy crops but excludes carbon stored in cultivated crops. For agricultural lands, FASOM CO_2 and N_2O EFs are from the DAYCENT/CENTURY model.

EPA compared FASOM LUC results from the control and corn only scenarios. For each scenario, the model summed LUC emissions over the period 2000–2022. To these values were added cumulative land-related emissions that occur in the 30 years following 2022 (reflecting continuing emissions from agricultural soils, decaying biomass, and wood products). For total cropland and total corn area the net changes were 0.581 and 1.477 million hectares, respectively. The difference in annualized emissions between the two scenarios was −4000 g CO2e/MMBtu, which was the RIA emissions value for this category [1].

We estimate domestic LUC emissions using results of a 2013 simulation of the Global Trade Analysis Project-Biofuels (GTAP-Bio) model and LUC emissions coefficients available in ANL's Carbon Calculator for Land Use Change from Biofuels Production (CCLUB) tool [11]. The GTAP-Bio 2013 results, developed in Taheripour and Tyner [12], include domestic and international land-use changes related to US corn ethanol production increasing from its 2004 level (GTAP-Bio's base period) to the RFS2 cap of 56.78 billion liters per year. Globally, the GTAP-Bio model estimates regional area changes for 18 agro-ecological zones (AEZs), and within each AEZ, changes in four land types (forests, grassland, cropland-pasture, and young forest shrub). Only AEZs 7–16 apply to US agriculture. For the United States, summing area changes across AEZs shows increasing US ethanol production resulted in conversions to cropland of 13,999 hectares of young forest shrub, 64,773 hectares of forest, 92,617 hectares of grassland and 1,788,462 hectares of cropland pasture (conversions by AEZ and land type are in Rosenfeld et al. [5, table 2-12]).

The CCLUB tool also includes LUC results for a similar analysis by Taheripour, Tyner, and Wang using a 2011 GTAP model [13]. Comparing the 2011 and 2013 GTAP results highlights how much new information has improved our understanding of the links between, and impacts related to, changes in corn ethanol markets and LUC relative to 2010. GTAP-Bio expands the set of land transformation elasticities from a single value to a set of region-specific values. GTAP-Bio also incorporates an improved cost structure that reflects the higher cost of converting forest to cropland versus converting pasture to cropland. Comparing the LUC results, conversions of young forest shrub, forest, and grasslands in the 2013 GTAP-Bio simulation are 79%, 80%, and 86% less, respectively, than in the 2011 simulation. There is also a 53% increase in conversions of cropland pasture to cropland. Overall, the GTAP-Bio analysis shows the large increase in US corn ethanol production since 2004 resulted in a large increase in land in corn production, a relatively small increase in aggregate agricultural land, and increases in cropland coming predominantly (over 90%) from cropland pasture.

We pair the GTAP-Bio AEZ-land type area changes with LUC emissions coefficients from the Century/COLE model. Relative to the RIA, which uses 2010 Century coefficients for agricultural land emissions, the coefficients used in our analysis better reflect irrigation effects and N_2O emissions from cropland and pasture.

The CCLUB tool also includes LUC emissions coefficients from Woods Hole (WH), and Winrock International (WI). We chose the Century/COLE coefficients because they align with the GTAP-Bio's AEZ-land-use type structure. The WH and WI coefficients apply to regions and have fewer land types. The WH coefficient set includes forest and grasslands; the WI set includes forest, grassland, and cropland-pasture. Hence, using the WH or WI coefficients with the AEZ-land type requires some aggregation across AEZs and land types. Additionally, distinct Century/COLE EFs are available for conventional and reduced tillage systems and soil depths of 30 and 100 cm. We assume the 100 cm soil-depth coefficients present a more complete picture of soil carbon changes than the 30 cm coefficients. We also note the conventional tillage scenarios are slightly less in absolute value (i.e. more conservative) than the reduced tillage coefficients. Based on these considerations, we use Century/COLE 100 cm conventional tillage coefficients to estimate the GHG emissions related to agricultural lands. The Century/COLE EFs by AEZ and land type for conventional and reduced tillage systems and soil depths of 30 cm and 100 cm are in Rosenfeld et al. [5, tables 2-14 and 2-15].

We aggregate emissions across all AEZ-land type combinations and then annualize the total using the CCLUB default value of 30 years. We divide these emissions by 43.87 (i.e. the increase in annual ethanol production, in billion liters, from 2004 to the RFS2 cap of 56.78 billion liters) to get emissions per billion liters of increased annual ethanol production. We convert these emissions to the common metric g CO_2e/MMBtu using a heating value of 20,166 Btu/L.

As shown in Table 2, our emissions value for the domestic LUC category is −2038 g CO_2e/MMBtu. The negative value indicates net sequestration associated with all ethanol-related LUC. This sequestration is due to: (1) over 90% of all new lands shifting into cropland coming from the cropland pasture category; and (2) the Century/COLE emissions coefficients for such conversions being negative across all AEZs. The net sequestration associated with conversion of cropland pasture to cropland reflects root growth deeper in the soil profile that more than offsets CO_2 emissions due to oxidation of carbon near the surface. Net emissions associated with conversions of forest, grassland, and young forest shrub are all positive. For completeness, Table 2 also shows domestic LUC emissions for our land use changes using the WH and WI EFs and the Century/COLE emissions factor for reduced tillage and 30 cm soil depth.

Finally, several recent studies examine changes in US agricultural land use between 2006 and 2012 using USDA's Cropland Data Layer (CDL) series. These studies conclude that over this period, increases in US corn ethanol production helped shift millions of acres from grassland uses (and some forest and wetland uses) to cropland, and produced a large increase in cropland acres planted to corn and corn/soybean systems. Wright and Wimberly [14], Lark et al. [15], and Wright et al. [16] extend the grassland conversion results to significant losses of native prairie and other long-term grasslands, and to previously unaccounted-for GHG emissions attributable to corn ethanol. Lark et al. [15] put the GHG emissions from recently converted lands used to grow corn or soybeans at 94–186 $MMTCO_2e$. For reasons developed below, we do not incorporate the results of these studies in our analysis.

The CDL is a land cover data product developed annually by USDA's National Agricultural Statistics Service (NASS) to provide detailed maps of commodity production over the growing season. NASS starts with a series of satellite images covering the contiguous 48 states. Each image consists of pixels with a resolution of 30 square meters. Each pixel is photographed multiple times between April and October, which gives a dynamic visualization of the pixel. A small set of cropland pixels are ground truthed to match with specific crops. Using this information, a software package assigns non-sampled cropland pixels to specific crops.

Extending conversions of grassland to cropland using CDLs to decreases in native prairie, or other long-term grassland, is not straightforward. CDLs do not distinguish

Table 2. Domestic land-use change emissions for GTAP 2013 simulation using emission factors from Century/COLE, Woods Hole, and Winrock International.

	Total direct emissions (Mg CO_2e)	Annualized emissions (Mg CO_2e/year)	Direct emissions (g CO_2e/L)	Direct emissions (g CO_2e/MMBtu)
Century/COLE – 30 cm – Reduced till	−52,191,279	−1,739,709	−39.65	−1965
Century/COLE – 100 cm – Reduced till	−62,656,429	−2,088,548	−47.60	−2359
Century/COLE – 30 cm – Conventional till	−45,625,214	−1,520,840.5	−34.66	−1718
Century/COLE – 100 cm – Conventional till	−54,120,694	−1,804,023.1	−41.13	−2038
Woods Hole	48,163,909	1,605,464	36.59	1813
Winrock International	280,879,558	9,362,652	213.4	10,577

Table 3. Methane emission factors from irrigated rice by region (in kg CO_2e/ha).

Study	Corn belt	Pacific Southwest	South central	Southeast	Southwest	United States
EPA RIA[a]	4512	4406	5557	N/A	10,811	N/A
Present[b]	5928	5310	7500	9222	11,421	7324

Sources: [a] [1, Table 2.4-9]; [b] [21]; N/A = not applicable; kg CO_2e/ha = kilograms of carbon dioxide equivalent per hectare.

Table 4. Changes in population, emission factors, and total emissions by livestock type.

		Enteric emissions		Manure management emissions		
Livestock type	Change in population (in 1000 head)	per head (g CO_2e/head)	Total emissions (g CO_2e/MMBtu)	per head (g CO_2e/head)	Total emissions (g CO_2e/MMBtu)	Total g CO_2e/MMBtu
Dairy	−20[a]	3625	−351	2065	−200	−551
Beef	90	1850	807	143	62	869
Poultry	−12,564.6[b]	–	NA	3.21	−195	−195
Swine	−220	37.5	−40	378	−403	−443
Total	NA	NA	416	NA	−736	−320

[a]Mature cows only.
[b]Population changes the same as in [1] except for poultry, which has been reduced to reflect annual average population changes rather than changes in total head slaughtered.
g CO_2e/head = grams of carbon dioxide equivalent per head; g CO_2e/MMBtu = grams of carbon dioxide equivalent per million British thermal units.

native from managed grasslands. In CDL studies, the 'grasslands' category includes native grasslands, pasture, cropland pasture, grass-hay, and land in the USDA's Conservation Reserve Program. Quantifying emissions adds another complexity because the emissions associated with any given pixel moving from grassland to cropland will depend on the prior grassland use and management practices. Satellite images do not show either. There is also the issue of allocating emissions among drivers. Farmers base land-use and production decisions on past and expected commodity prices. Since 2006, domestic and world corn and soybeans prices have been historically high. In addition to increased ethanol production, these high prices reflect global population growth, increases in global demands for livestock products, and a series of severe weather events that disrupted global and US commodity markets. Analyzing the high US corn prices between 2006 and 2009 relative to 2004, Babcock and Fabiosa [17] conclude that 32% of the higher annual prices were attributable to ethanol and 64% to other factors.

Finally, the CDL is one of several national-scale land-cover data products developed by US government agencies. Others include the Forest Service's Forest Inventory Assessment, the USDA's Natural Resources Inventory, and the US Geological Survey's National Land Cover Database. Focusing on 20 counties in the Prairie Pothole Region between 2004 and 2014, Dunn et al. [18] show that estimates of conversions of grassland, forest, and wetlands to cropland vary significantly depending on the land cover product and analytical techniques used.

Domestic rice methane

US rice production is a source of CH_4 emissions due to organic material decomposing under anaerobic conditions in flooded fields. In the RIA, a decrease in rice hectares accounts, in part, for the RFS2-driven increase in corn hectares. This results in a decrease in CH_4 emissions.

EPA used FASOM simulations for the control and corn only scenarios to project RFS2 corn ethanol mandate-driven changes in rice hectares in 2022 at −23,790. These hectares were allocated across domestic rice-producing regions and each region's hectares were multiplied by a region-specific per-hectare emissions coefficient from EPA [19]. EPA estimated the RFS2-related change in CH_4 emissions from decreased rice production at −42,000 metric tons CO_2e, which converted to −209 g CO_2e/MMBtu [1].

Domestic rice is a small emissions category and little new information has emerged since 2010 indicating US rice area has responded to the RFS2 along a significantly different path than that projected in the RIA. Hence, we use the RIA change in total domestic rice hectares, but allocate them regionally based on their current distribution. As shown in Table 3, since 2010, EPA has increased the per-hectare CH_4 EFs for rice production and the IPCC has increased the GWP value for CH_4 from 21 to 25. We incorporate both adjustments in calculating changes in regional rice emissions. Summing emissions across regions and dividing by 9.84 billion liters yields a per-liter emissions value. Applying a heating value for ethanol of 20,166 Btu/L, our emissions value for Domestic rice methane is −1013 g CO_2e/MMBtu.

Domestic livestock

This category includes changes in CH_4 emissions from enteric fermentation and changes in CH_4 and N_2O emissions from manure management. These sources account for about 47% of GHG emissions from US agriculture [20]. Enteric fermentation from dairy cows and beef cattle and manure management on dairy, beef, and swine operations

Table 5. Reduced Methane Emissions from Distillers Grains as Animal Feed by Ethanol Plant Type.

Ethanol plant type	Ethanol market share (%)	Dried DGS yield (g/L)	Wet DGS yield (g/L)	Emissions reduced (g CO_2e/L)	Emissions reduced (g CO_2e/MMBtu)
Dry mill with out corn oil extraction	17.7	504.1	661.7	−50.46	−2506
Dry mill with corn oil extraction	70.9	482.2	632.9	−48.34	−2397
Wet mill	11.4	–	–	–	–
Per average liter	–	431.1	565.9	−43.21	−2143

g/L: grams per liter; g CO_2e/L: grams carbon dioxide equivalent per liter; g CO_2e/MMBtu: grams carbon dioxide equivalent per million British thermal units.

account for about 95% of US livestock emissions. Increases in US corn ethanol production affect changes in livestock emissions through changes in animal populations, feed prices, and feed mixes. Corn is the most important feed input used in confined dairy, beef, swine, and poultry operations. While increases in corn ethanol production have helped drive historically high corn and feed prices since 2005, feed price impacts have been moderated by increased production of feed co-products, mainly DGS. When substituted for corn in cattle feed, DGS (dried or wet) reduces CH_4 emissions from enteric fermentation [1].

In the RIA, the RFS2-driven impacts of higher corn ethanol production on feed prices, livestock numbers, and livestock-related emissions are assessed using FASOM simulations for the 'control case' and the 'corn only case'. FASOM projected the RFS2 would increase feed prices; reduce the populations of dairy cattle, swine, and poultry; increase the population of beef cattle; and reduce livestock-related emissions of CH_4 and N_2O. FASOM assesses livestock-related emissions on a per-head basis. Hence, a change in animal numbers results in a change in emissions in the same direction. An adjustment is made to capture the lower per-head enteric fermentation emissions for cattle fed DGS in place of corn. For this source category, the RIA projected emissions in 2022 at −3746 g CO_2e/MMBtu.

Since 2010, little new information has appeared to indicate that the relationship between feed prices and domestic livestock populations has changed significantly from those in the RIA's FASOM simulations. Given this, the relatively small magnitude of the emissions category, and annual corn ethanol production in the RIA being 56.78 billion liters from 2015 through 2022, we use the RIA's 2022 projections for changes in dairy cow, beef cattle, and swine populations in our analysis. For poultry, we reduced the RIA population change by 75%, because the RIA appears to include changes in poultry slaughtered instead of the annual average poultry population. The time from hatch to slaughter for poultry species is generally 3 to 4 months. Hence, it takes 3–4 slaughtered birds to apply a per-head annual emissions factor. We combined the changes in animal populations with annual EFs from the official 2016 US greenhouse gas inventory [21]. These EFs incorporate changes EPA has made in methodologies for computing emissions for different types of livestock and the AR4 GWPs for CH_4 and N_2O. Table 4 shows changes in populations, per-head annual EFs, and total emissions by livestock type.

To capture CH_4 emission reductions associated with feeding cattle DGS in place of corn, we use emissions reduction factors from the GREET 2015 (i.e. 0.183 kg CO_2e/dry kg of dried DGS (DDGS) and 0.130 kg CO_2e/dry kg of wet DGS (WDGS) for every dry kilogram of DGS consumed by beef cattle). Based on Renewable Fuels Association data [22], beef cattle consume 45% of DGS. Table 5 shows, by plant type, wet and dry DGS yields per liter of ethanol and emission reductions per liter and in g CO_2e/MMBtu). Table 5 also shows the ethanol market shares by type of plant, which we use to calculate the emissions reduction for an 'average' liter of ethanol.

Combining the reduced emissions from changes in animal populations (−320 g CO_2e/MMBtu) with the reduced emissions from using more DGS in livestock diets (−2143 g CO_2e/MMBtu) we assess domestic livestock emissions at −2463 g CO_2e/MMBtu. This is about two thirds the RIA value, and it reflects differences in the CH_4 emissions reduction factors associated with feeding beef cattle DGS in place of corn in the GREET 2009 and 2015 models.

International livestock

As in domestic feed markets, large increases in the US ethanol industry's demand for corn have helped drive higher prices in international feed markets. This has affected changes in global livestock populations, which in turn has affected changes in CH_4 emissions from enteric fermentation and CH_4 and N_2O emissions from manure management.

The RIA grouped international livestock into seven regions (Canada, Western Europe, Eastern Europe, Oceania, Latin America, Africa, the Middle East, and India). Simulations of the Food and Agriculture Policy and Research (FAPRI) - Center for Agricultural and Rural Development (CARD) model for the 'control case' and the 'corn only case' were used to evaluate changes in regional populations of dairy and beef cattle, swine, sheep, and poultry in response to RFS2-driven changes in international feed prices. The changes in regional livestock populations were multiplied by region- and livestock-specific, per-head GHG EFs. The EFs for both the enteric fermentation and the manure management emissions reflected the default IPCC EFs, which account for differences in regional livestock systems [10]. EPA projected emissions for this category in 2022 at 3458 g CO_2e/MMBtu.

Since 2010, little new information has appeared to indicate that the FAPRI-CARD relationships between feed prices and international livestock production have changed significantly. Given this, the relatively small magnitude of the emissions category, and annual corn ethanol production in the RIA being 56.78 billion liters from 2015 through 2022, we use the RIA's 2022 projections for changes in regional dairy cattle, beef cattle, swine, sheep, and poultry populations for our analysis. Population changes by region and livestock group are available in Rosenfeld et al. [5].

With one exception, we use the RIA's region- and livestock-specific EFs for enteric fermentation and manure management; however, we adjust these factors to reflect the AR4 GWPs for CH_4 and N_2O. While updated activity EFs are available for a number of countries, it is difficult to justify applying these factors to changes in livestock populations in regions that are multi-county aggregates. The

Table 6. iLUC emissions by scenario, emissions factor set, and annualized emissions value.[a]

Scenario	Emission factor (EF) data set	Emissions (g CO_2e/MMBtu)[c]
	RIA [1] analysis	
FAPRI-CARD	Winrock	31,790
	Scenarios making up composite iLUC emissions value used in this analysis	
GTAP 2013	CARB AEZ Model	17,802
GTAP 2013[b]	Winrock	5913
GTAP 2013 adjusted with data in [26]	CARB AEZ Model	8464
GTAP 2013 adjusted with data in [26]	Winrock	1326
CARB 2015 [27]	CARB AEZ Model	20,890
Dunn et al. 2015 [11]	Winrock	5286
[11]	Woods Hole	3893

[a]Scenarios in [11] and the four scenarios we construct use land conversion results published by [26]. [27] modified some important factors and values within the GTAP-Bio model to produce their own unique land conversion results.
[b]Emissions vary in these studies because within each region, [11] used an average of the individual country EFs, while we weight countries' EFs by their share of regional arable land.
[c]All studies assume emissions from land conversions occur over 30 years. This column shows annualized values. The RIA and GTAP-Bio 2013 consider different volume increases in corn ethanol production. Describing emissions in g CO_2e/MMBtu puts all emissions in a comparable metric.
Abbreviations: iLUC = international Land Use Change; g CO_2e/MMBtu = grams carbon dioxide eqivalent per million British thermal units; RIA = Regulatory Impact Analysis; FAPRI- CARD = Food and Agricultue Policy Research Institute-Center for Agricultural and Rural Research model; GTAP = Global Trade Analysis model; CARB = California Air Resources Board; AEZ = Agricultural-Ecological Zone.

Table 7. Mode and distance assumptions.

	Farm to stacks		Stacks to plant		Plant to blending terminal		Terminal to retail station		DGS[a]		Corn oil	
Mode	% of total shipped	Distance (km)	% of total shipped	Distance (km)	% of total shipped	Distance (km)	% of total shipped	Distance (km)	% of total shipped	Distance (km)	% of total shipped	Distance (km)
Barge	0	0.0	0	0.0	13	837	0	0.0	2	837	0	0
Rail	0	0.0	0	0.0	79	1287	0	0.0	12	1287	20	644
Truck	100	16.1	100	64.4	8	129	100	48.3	86	80	80	161

[a]The values shown in these columns reflect a weighted average dry and wet distiller grains and solubles (DGS) co-product.

exception was Canadian cattle, where updated factors were available and the region consisted of only Canada.

Given these adjusted EFs, our emissions value for the international livestock source category is 3894 g CO_2e/MMBtu. This value is somewhat higher than the RIA value and reflects the updated EFs for Canadian cattle and the higher GWP for CH_4.

International land-use change

iLUC is the largest emissions category in the RIA LCA. It encompasses indirect emissions associated with farmers outside the United States shifting new land into commodity production in response to increases in global commodity prices driven by the RFS2 corn ethanol mandate. For the RIA, EPA used simulations of the FAPRI-CARD model to assess global agriculture's response to the RFS2. FAPRI-CARD can assess changes in area and production across 20 crops and 54 regions in response to changes in international and domestic commodity prices. For 2022, FAPRI projected the RFS2 corn ethanol mandate would increase cropland outside the United States by 789,000 hectares and decrease pasture by 446,000 hectares. Among regions, Brazil accounted for the largest share of new cropland (approximately 316,000 hectares) [1, see fig. 2.4-47].

While FAPRI can assess how much new land will shift into commodity production in response to a global commodity market shock, it cannot distinguish the types of land that shift. The FAPRI-CARD projected changes in regional land areas used for commodity production (crops and livestock) were analyzed by WI to determine the types of land, and the quantities of each land type, that would be affected. WI's methodology drew on MODIS (Moderate Resolution Imaging Spectroradiometer) satellite data covering the period 2001 to 2007 [23,24] and expert opinion to quantify, by region, conversions and reversions of land to commodity production from forest land, from grassland, and from cropland-pasture. Summed across regions, the RIA projected emissions in 2022 for the iLUC source category at 31,790 g CO_2e/MMBtu.

Since 2010, several new studies have assessed the iLUC impacts associated with the corn ethanol mandates in the RFS and RFS2 [11,12,25–28]. These studies employ data, modeling capabilities, and other information that were not available for the RIA. Viewed collectively, three results stand out. First, the studies all find significantly lower iLUC emissions than were projected in the RIA. Second, across studies, estimates of corn ethanol-driven iLUC emissions trend down over time. Finally, two research groups, the California Air Resources Board (CARB) [27, 29] and Dunn et al. [11, 25], look at the issue twice. Each finds iLUC-related emissions to be significantly lower (by 33–60%) in their second analysis. Given that the RIA projected emissions path for iLUC is flat from 2015 onward, the new research strongly indicates that actual iLUC emissions related to corn ethanol are much lower than was projected in the RIA.

Except for Babcock and Iqbal [26], the studies cited above employ some version of the Global Trade Analysis Project (GTAP) model. Most use the 2013 GTAP-Bio (for biofuels) model described in Tahierpour and Tyner [12]. Relative to the FAPRI-CARD model used in the RIA and the GTAP model used in CARB [29], the 2013 GTAP-Bio model has several upgrades that make it better suited to analyzing the iLUC impacts related to increases in US corn ethanol production. First, its base period is 2004. Hence, all simulations are relative to the year before implementation of the RFS. Second, the model includes region-specific land transformation elasticities developed from two United Nations Food and Agriculture Organization (FAO) land-

Table 8. Assumptions and inputs for fuel production modeling in GREET 2015.

Input category	Dry milling plant without corn oil extraction[a]	Dry milling plant with corn oil extraction[a]	Wet milling plant[b]
Total energy use for ethanol production (MJ/L)	28.33	27.88	50.02
Process fuel energy – natural gas, coal, and biomass (MJ/L)	25.66	25.18	50.02
Electricity use (kWh/L)	0.195	0.198	0.00
Co-product yield – dry DGS to animal feed (g/L ethanol)	504	482	0.00
Co-product yield – wet DGS to animal feed (g/L ethanol)	661	633	0.00
Co-product yield – CGM to animal feed (g/L ethanol)	0.00	0.00	162
Co-product yield – CGF to animal feed (g/L ethanolc	0.00	0.00	702
Co-product yield: Corn oil (actual g/L ethanol)	0.00	22.77	117
Ethanol yield (L/bushel)	10.6	10.7	9.88
GHG emissions (g CO_{2e}/MMBtu)	32,114	31,590	53,055

[a]These are composite refineries reflecting the 2014 mix of natural gas, coal, and biomass as a process fuel at the respective dry mill refineries.
[b]Electricity consumption is included with process fuel energy.
Abbreviations: GREET = The Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation Model; MJ/L =Mega Joules per liter; kWh/L = kilowatt hours per liter; g/L = grams per liter; L/bushel = liters per bushel; g CO_2e/MMBtu = grams CO2 equivalent per million Britsh thermal unit; RIA = Regulatory Impact Analysis; BAU = Business as Usual Scenario; HEHC = High Efficiency - High Conservation Scenario

cover datasets. Finally, the model explicitly accounts for the higher cost of converting forest to cropland relative to the cost of converting grassland. The complete set of global land-use changes generated by Taheripour and Tyner [12] is available in ANLs CCLUB model.

While commodity production data show that farmers in the US and in other regions did increase commodity production in response to historically high commodity prices over the period 2004–2012, Babcock and Iqbal [26] show most of these increases were achieved by farmers using existing cropland more intensely rather than by bringing new land into production. For example, comparing Brazilian data for 2004–2012 on planted, harvested, and double-cropped hectares, they found increased use of double cropping accounted for 76% of the increase in harvested area. For China and India over the same period, they found virtually all of the increases in harvested area were due to intensification. In China, the driver was increased use of double cropping, while in India the drivers were increased use of double cropping (33%) and decreases in idle cropland (67%). This is important from an LCA perspective because bringing new land into production generally entails much higher GHG emissions than does using existing cropland more intensely.

To see how increased intensification might affect the iLUC impacts in the GTAP 2013 land-use change results, we apply the Babcock and Iqbal [26] intensification measures for five regions (i.e. Brazil, China, India, Indonesia, and sub-Sahara Africa) to their cropland increases in the 2013 GTAP results. Regional conversions to cropland from forest, grassland, and cropland pasture in the 2013 GTAP-Bio simulation are shown in Rosenfeld et al. [5, table 2-37] both with and without the regional intensification adjustments. Aggregated across regions, intensification reduces hectares converted by 775,000, which is almost 60% of total hectares converted in the 2013 GTAP results.

To assess iLUC emissions associated with increases in US corn ethanol production requires linking regional shifts of land into commodity production with a set of associated EFs. The RIA employs a set of iLUC EFs developed by WI. The WI EFs reflect historical land-use trends identified using MODIS satellite imagery from 2001 and 2007, and include region-specific factors by type of land converted. A second set of EFs are those developed by WH. The WH EFs incorporate region- and biome-specific values for belowground carbon, biomass carbon, and carbon growth factors. The WI and WH EF sets are options in the ANL CCLUB model, but neither aligns exactly with the GTAP 2013 AEZ structure. Hence, using GTAP 2013 iLUC results with either the WI or WH EF set requires some aggregation of land conversions across land types and AEZs within each region.

A third set of iLUC EFs is available from the Low Carbon Fuel Standard Agro-ecological zones (AEZ) model (a GTAP model tailored to California) used by CARB [27]. The CARB AEZ EFs are not included in the ANL CCLUB model but are completely consistent with the 2013 GTAP region-AEZs structure. This makes computing iLUC-related emissions for GTAP 2013 simulation results relatively straightforward.

To assess the contribution of iLUC emissions to corn ethanol's GHG profile, we compute the average iLUC emissions for seven scenarios. Three scenarios are directly from CARB [27] and Dunn et al. [11]. Four scenarios we construct using the regional iLUC impacts from Tahierpour and Tyner [12], the CARB and WI EFs, and the regional data on intensification in Babcock and Iqbal [26]. Table 6 details the seven scenarios, their EF sets, and their iLUC emissions values. The average annual iLUC emissions of these seven scenarios is 9082 g CO_2e/MMBtu. This is our emissions value for the iLUC category.

International farm inputs and fertilizer N_2O

This category includes emissions related to changes in the use of chemical and energy inputs by farmers outside of the United States responding to changes in global commodity markets driven by increases in US corn ethanol production. EPA utilized FAPRI-CARD simulations to assess changes in harvested area and production by crop and country. Fertilizer application rates per hectare came from the International Fertilizer Industry Association (IFA) [30] and FAO [31]. Herbicide and pesticide activity data came from FAO [31] and, for China, USDA's Economic Research Service (ERS) [32]. EFs for fertilizers, herbicides and pesticides came from GREET 2009 [33]. Direct and indirect N_2O emissions from synthetic fertilizer were estimated using an approach analogous to that used for domestic direct and indirect N_2O emissions.

For energy inputs, EPA used International Energy Agency (IEA) data on farm-sector use of diesel, gasoline, and electricity by country [34]. Emissions associated with use of these inputs were calculated using IEA country-level GHG EFs. Farm-sector emissions were scaled up to life-cycle emissions based on the ratio of combustion to life-cycle GHG emissions from US electricity and fuel use [34]. For each country, dividing the total life-cycle emissions by the area of arable land in the FAOStat land area database [31] yielded per-hectare LCA emissions.

Multiplying the per hectare emissions by the FAPRI-CARD country-level changes in harvested hectares yielded total fuel-related emissions related to the RFS2 corn ethanol mandate. Summed across countries and inputs, the RIA projected emissions in 2022 for this category at 6601 g CO_2e/MMBtu. This projection, however, reflects the FAPRI-CARD extensive margin response of international agriculture to the RFS2-driven increase in US corn ethanol production. As discussed, information not available in 2010 indicates international agriculture's primary response to increases in US corn ethanol production has been to use existing cropland more intensely. Since the RIA overestimates the amount of new land shifted into commodity production, it overestimates the emissions associated with the use of chemical and energy inputs.

We assess emissions for the international farm inputs and fertilizer N_2O category based on the international acreage responses to increased US corn ethanol production in the GTAP 2013 results available in ANL's CCLUB model [11]. Since the base year for the GTAP 2013 model is 2004, its iLUC results reflect the new land brought into commodity production outside the United States in response to the ethanol mandates in the original RFS and the RFS2. That is, the GTAP 2013 iLUC results reflect an increase of 43.87 billion liters of US corn ethanol. To make the 2013 GTAP iLUC numbers more directly comparable to the FAPRI-CARD values in the RIA, we convert both to new hectares brought into commodity production per million liters increase in US corn ethanol. The GTAP 2013 and FAPRI-CARD values are 29.59 and 80.05 ha/million liters, respectively.

We follow the general RIA approach to estimate average per-hectare emissions associated with international agriculture's use of chemical and energy inputs. Country-level per-hectare application rates are from FAO and IEA data compiled in FAOStat [31]. We update the herbicide and pesticide use data to reflect the most current data available from FAO's FAOStat dataset for pesticide consumption [31]. For multi-country GTAP regions, we compute weighted average application rates with the weights being each country's share of its region's stock of arable land. Arable land area came from FAO [31]. Life-cycle EFs for nitrogen, phosphate, potassium, calcium carbonate, and insecticide are from GREET 2015. Life-cycle EFs for herbicides and insecticides are from ecoinvent v2 found in SimaPro [9].

We calculate direct and indirect N_2O emissions based on IPCC guidance [10]. The guidance uses applied nitrogen fertilizer rates to assess the direct impacts including the N additions from fertilizer, and the N mineralized from soil due to the loss of soil carbon. The N fertilizer application rate is also used to calculate the indirect emissions from volatilization and leaching [10].

Emissions associated with the use of energy inputs are calculated using IEA data on total CO_2 emissions from agricultural fuel combustion by country. These emissions are combined with country-level emissions related to agriculture's use of electricity. The total emissions are then scaled to represent the full life-cycle GHG emissions for each country. We did not update the RIA EFs for energy inputs because IEA no longer releases country-specific EFs.

The per-hectare emission rates developed for chemical and energy inputs are multiplied by the amount of new land in each GTAP region shifting into commodity production in response to increased US corn ethanol production. Converted to the common energy metric, we assess emissions for this category at 2217 g CO_2e/MMBtu. This value is about a third of the RIA value and reflects the much lower LUC response per million liter increase in US corn ethanol production in GTAP 2013 relative to the 2010 FAPRI-CARD model.

International rice methane

This category captures CH_4 emissions related to RFS2-driven changes in rice area outside of the United States. EPA projected these emissions based on IPCC guidance [10], country-level data on rice area harvested and length of growing season, and default IPCC EFs for irrigated, rainfed lowland, upland, and deepwater rice production systems [10]. Country values for the rice-growing season came from the International Rice Research Institute (IRRI) [35]. FAPRI-CARD simulations projected annual country-level values for rice production and harvested acres under the 'control case' and the 'corn only case' scenarios. Comparing these simulations, the RIA projected international rice area in 2022 would increase by 58,344 hectares in response to the RFS2 corn ethanol mandate.

Multiplying the country-specific changes in rice acres by the appropriate production system EF(s) and summing across countries, the total projected change in CH_4 emissions in 2022 was 19,918 Mg CH_4. This converted to 2089 g CO_2e/MMBtu [1]. Country values for changes in rice area and emissions are in Rosenfeld et al. [5, table 2-48].

International rice methane is a relatively small emissions category in the RIA and very little new information indicates a need to change the RIA methodology or emissions estimate. Hence, we use the RIA's country-specific changes in rice acres and CH_4 emissions (i.e. 19,918 Mg CH_4). We multiply these emissions by the AR4 CH_4 GWP to get the CO_2 equivalent. We then divide the CO_2 equivalent by 9.84 billion (i.e. the RFS2-related increase in US corn ethanol production in 2022) to get an equivalent emissions per liter. We convert this to g CO_2e/MMBtu using the heating value 20,166 (Btu/L). Our value for the international rice methane emissions is 2483 g CO_2e/MMBtu.

Fuel and feedstock transport

CO_2 emissions from combusting gasoline and diesel fuels occur in transporting corn from farm to refinery, ethanol from refinery to retail station, and co-products from refinery to end users. While this category accounts for 5–6% of ethanol's GHG profile, transportation vehicles and systems have become more fuel and GHG efficient since 2010 [36].

The RIA drew on a combination of sources to determine fuel and feedstock transportation emissions. From GREET 2009, corn was assumed to move 10 miles by truck from the farm to a central collection point (i.e. the stack) and 40 miles by truck to the refinery. An Oak Ridge National Laboratory (ORNL) study provided projected 2022 fuel transportation modes and distances for ethanol from refinery to the blending terminal [37]. For co-products, the EPA obtained data from the USDA on modes and distances for transporting DGS from refineries to final users [1]. For each mode of transportation and associated distance traveled, GREET default assumptions and EFs were used. The

RIA projected 2022 emissions for the fuel and feedstock transport category at 4265 g CO_2e/MMBtu. The RIA did not consider transportation requirements for corn oil.

Our method is similar to that of the RIA but incorporates updated assumptions, transportation mode and distance traveled data, and EFs from GREET 2015. Relative to GREET 2009, GREET 2015 includes: (1) new LCA EFs for five types of diesel and gasoline freight vehicles; (2) new transportation mode and distance traveled data for ethanol moving from refinery to blending terminal and from blending terminal to retail station; and (3) new life-cycle freight EFs for rail, barge, and truck [36]. For corn oil, transportation emissions reflect the same emissions per ton-mile as for DGS. Table 7 shows the modes and distances for transporting corn, ethanol, DGSs, and corn oil used in our analysis. For the columns labeled Farm to stacks, Stacks to plant, and DGS, the values are the same as in the RIA. We assess emissions for this category at 3,432 g CO_2e/MMBtu. Of this, 57.3%, 33.8%, 8.3% are for the transportation of, respectively, corn, ethanol, and DGS.

Fuel production

This category includes emissions related to energy use at refineries. Across refineries, energy use per unit of ethanol varies significantly. Major determinants are the type of refining process (i.e. wet or dry milling), the process fuel used (i.e. natural gas, coal, or biomass), the set of co-products produced (wet DGS, and dry DGS), and the quantity of electricity purchased from the grid. For the RIA, EPA developed a table from various sources detailing projected 2022 energy use by refineries across these factors [1, table 2.4-55].[8] Based on these energy use values, various EFs from the GREET 2009 model, and assumed yields of ethanol per kilogram of corn (0.40 L for dry mill plants and 0.37 L for wet mill plants), EPA projected 2022 emissions profiles for a variety of refinery configurations [1, fig. 2.6-3]. The GREET model coefficients included: (1) emissions from combustion of natural gas and coal; (2) upstream emissions for natural gas, coal, and biomass; and (3) emissions associated with the production and use of purchased electricity [1, 33].

For the RIA LCA, EPA constructed a 'representative' new dry mill refinery in 2022 that uses natural gas for a process fuel, produces a DGS mix that is 63% dry and 37% wet, and has a fractionation technology in place for extracting corn oil from the DGS. EPA projected emissions for the fuel production category at 28,000 g CO_2e/MMBtu in 2022.

Since 2010, production efficiencies have improved and GHG intensities have fallen in the US corn ethanol industry. There has been an ongoing shift from coal to natural gas as a process fuel. The use of new enzymes and yeast strains has increased efficiencies in starch conversion and fermentation so refineries are getting more ethanol per bushel of corn [38]. Finally, many refineries now recover corn oil as a co-product. We draw on the set of corn ethanol production pathways and their associated EFs available in GREET 2015. Many of these pathways are new or updated relative to GREET 2009 and better reflect the production technologies and energy use at refineries today. The updated pathways include: (1) an ethanol industry average – 92% natural gas, 8% coal; (2) dry mill – 100% natural gas; (3) dry mill – 100% coal; (4) dry mill – 100% biomass (forest residue); and (5) wet mill – 72.5% natural gas, 27.5% coal. Table 8 shows the assumptions on energy use, co-product yields, ethanol yields, and GHG emissions for these pathways.

For co-products, drying DGS and extracting corn oil requires energy. When accounting for DGS as a co-product, we used the displacement method (described previously). The energy and emissions related to DGS drying are allocated to the fuel production category and a credit is given for DGS displacing corn grown for animal feed. As noted, we allocate the entire co-product credit to the *domestic farm inputs and fertilizer N_2O* category. For corn oil, we used the marginal method, which does not allocate the energy or the emissions related to corn oil extraction to the ethanol production process and does not award the process a credit based on reducing the GHG intensity of downstream products or replacing other feedstocks.

To assess fuel production emissions, we construct a composite refinery reflecting a weighted average of current dry and wet milling production processes (18% dry milling without corn oil extraction, 71% dry milling with corn oil extraction, and 11% wet milling). Our weighted industry average emissions level is 34,518 g CO_2e/MMBtu. This value is higher than in the RIA and reflects some refineries still using coal as a process fuel.

Tailpipe

Combusting ethanol in motor vehicles emits CO_2 from the tailpipe. These emissions are biogenic and are assumed to be offset by the removal of CO_2 from the atmosphere during new biomass growth. Ethanol combustion also emits CH_4 and N_2O, which remains in the atmosphere. Using the 2009 Motor Vehicle Emission Simulator (MOVES), EPA projected these emissions at 269 g CO_2e/MMBtu for CH_4 and 611 g CO_2e/MMBtu for N_2O [1, 39].[9] Summing these values, the RIA projected tailpipe emissions in 2022 at 880 g CO_2e/MMBtu.

Since 2010, new estimates of the CH_4 and N_2O emissions associated with combusting ethanol have been published by the Washington Department of Ecology [40] (187 g CO_2e/MMBtu), the State of California GREET model [41] (613 g CO_2e/MMBtu) and GREET 2015 (578 g CO_2e/MMBtu). All three values are less than the value in the RIA. The GREET-affiliated estimates have a small downward bias because they reflect E85, not pure ethanol as in the RIA. The Washington Department of Ecology emissions estimate reflects pure ethanol but it has the largest difference from the RIA value. Given that this is the smallest emissions category and given our overall reliance on GREET 2015 EFs, we select 578 g CO_2e/MMBtu as the emissions value for this category.

Projected GHG LCA emissions in 2022 for BAU and HEHC scenarios

Starting with our current emissions profile of corn ethanol, we develop two projected emissions profiles for 2022. The first projection, labeled the BAU scenario, continues through 2022 current trends in: (1) per-hectare corn yields (increasing by 125.7 kg/ha/year [42]); (2) refineries switching from coal to natural gas as a process fuel; and (3) increasing fuel efficiency in heavy-duty diesel trucks. The BAU scenario reflects

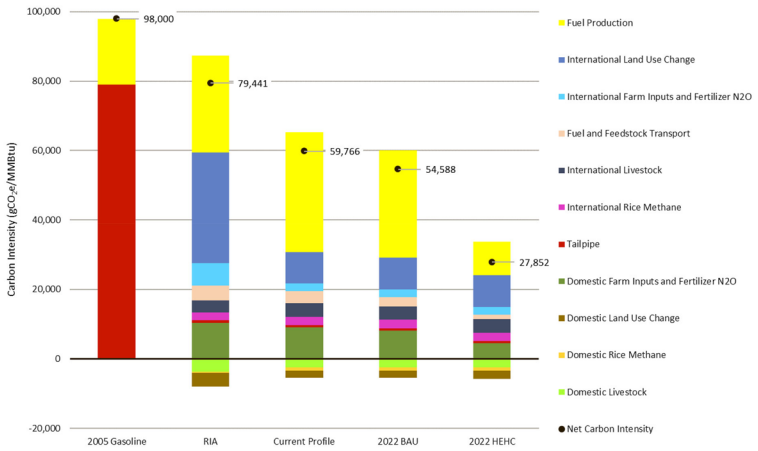


Figure 1. Life-cycle GHG emissions for gasoline and corn ethanol by scenario and source category. RIA: Regulatory Impact Analysis; BAU: Business as Usual Scenario; HEHC: High Efficiency - High Conservation Scenario; N_2O: Nitrous Oxide.

expected improvements in corn ethanol's GHG profile in 2022 without refineries acting to reduce emissions. The second projection, the HEHC scenario, adds to the BAU scenario several actions refineries could take to reduce the GHG intensity of corn ethanol. These include contracting with farms to grow corn using low-emissions practices (reduced tillage, cover crops, and nutrient management), switching to sustainably produced biomass as a process fuel, and locating confined livestock operations close to refineries.[10]

Contracting with farmers (reduced tillage, nitrogen management, and cover crops)

The current and BAU GHG scenarios assume farmers grow corn for ethanol using conventional tillage. Relative to conventional tillage, reduced tillage systems increase soil carbon levels, decrease CO_2 emissions from fuel combustion in field operations, and decrease N_2O emissions from volatilization. For the HEHC scenario, we estimate increased soil carbon impact of farmers adopting reduced tillage by matching US corn hectares by AEZ from the GTAP 2013 simulation with the corresponding AEZ soil carbon emissions coefficients using both conventional and reduced tillage. Summed across AEZs, the emissions impact is −321 g CO_2e/MMBtu (in Table A2, compare the domestic LUC values for the 'current conditions' and the '2022 HEHC' scenarios). To account for the emissions impact of lower diesel fuel consumption, we decrease the use of diesel in farm operations from 76.36 L/ha under conventional tillage to 64.98 L/ha for reduced tillage [7]. Finally, the shift from conventional to reduced tillage reduces the volatilization rate of applied nitrogen. The COMET-Planner report attributes a 0.173 Mg CO_2e/ha/year reduction in emissions to reduced tillage relative to conventional tillage. This represents a 74.4% reduction in N_2O emissions from volatilization, which we incorporate into the HEHC scenario.

If they are not doing so already, farmers can reduce applied N and the associated N_2O emissions by targeting N applications and using N inhibitors [5]. The COMET-Planner report estimates these practices can reduce N application rates by 15%. We make this adjustment to the application rates in the HEHC scenario. There is little publicly available data with which to quantify the upstream emissions associated with N inhibitors. As a proxy, we use an application rate of 5.53 kg/ha [43, 44] and manufacturing process emissions for the 'organophosphorus-compound' from the ecoinvent database [9].

Cover crops protect soils between harvest and planting. Using cover crops can reduce indirect N_2O emissions related to leaching of N fertilizer. The COMET-Planner attributes a 1.24 Mg CO_2e/ha/year reduction in emissions to cover crops. This is a 76.8% reduction in N_2O emissions from leaching, which we incorporate in the HEHC scenario.

Comparing the BAU and HEHC scenarios indicates that in 2022, refineries can reduce emissions by 4021 g CO_2e/MMBtu by contracting with farmers to grow corn using reduced tillage, nitrogen management, and cover crops (sum the differences in emissions for 'domestic farm inputs' and 'domestic LUC' between BAU and HEHC scenarios in Table A2).

Fuel production

For the current GHG profile of corn ethanol, we assess emissions for the fuel production category by constructing a composite process fuel reflecting a weighted average of fuels currently used by refineries. For the 2022 projections, we focus on refineries that use dry milling technologies. The ethanol industry has been shifting to dry milling due largely to the high capital costs of wet mill refineries [45]. In 2013, 83% of US corn ethanol refineries used dry mill technologies. Rosenfeld et al. [5] describe fuel production emissions for dry mill refineries, with and without corn oil extraction, and using different process fuels. Our BAU scenario assumes a dry mill refinery with corn oil extraction using natural gas as its process fuel. Fuel production emissions for this refinery are 31,006 g CO_2e/MMBtu. Our HEHC scenario assumes the same refinery using biomass as its process fuel. The HEHC scenario also incorporates a higher

ethanol yield per bushel of corn than in the BAU scenario, 0.44 versus 0.42 L/kg of corn. Fuel production emissions for the HEHC refinery are 9695 g CO_2e/MMBtu.

Fuel and feedstock transportation

For the current GHG profile of corn ethanol, we use default GREET 2015 transportation and distribution EFs, mode allocations (i.e. barge, truck, or rail), and distance assumptions to generate transportation-related emissions (see Table 7). For the 2022 BAU and HEHC projections, we adjust the default GREET 2015 emissions to reflect a 50% increase in fuel efficiency for heavy-duty diesel trucks and an increase in the use of liquefied natural gas (LNG)- and renewable LNG-powered heavy-duty trucks. The BAU includes a transition of feedstock, fuel, and corn oil transport to LNG and DDGS transported by diesel. The HEHC included a full transition to renewable LNG, increased in part due to renewable natural gas from landfills qualifying as an advanced biofuel. Additionally, the HEHC scenario assumes the location of confined animal feeding operations (CAFOs) near ethanol plants and we eliminate emissions related to transporting DDGS. For the BAU and HEHC scenarios, emissions related to transporting of fuel and feedstock are projected at 2641 and 1237 g CO_2e/MMBtu, respectively.

Discussion

Figure 1 shows the RIA GHG profile for gasoline, the RIA projected GHG profile for corn ethanol in 2022, our current GHG profile for corn ethanol, and our two projected GHG profiles for corn ethanol in 2022. Appendix Table A2 provides the emissions values by source category for each ethanol scenario.

In the RIA, EPA quantified the LCA emissions associated with its 'average' 2005 gasoline (see note 1) at 98,000 g CO_2e/MMBtu. For corn ethanol, the RIA projected emissions in 2022 at 79,441 g CO_2e/MMBtu. The ethanol is produced at a new natural gas-powered dry mill refinery, with a fractionation process in place for extracting corn oil, and producing a DGS mix that is 63% dry and 37% wet. Interestingly, the projected emissions for corn ethanol fall just short of the 20% reduction required in the RFS2 to qualify as a renewable fuel. EPA assumed there would be additional emissions reductions by 2022 related to increased efficiencies (e.g. in drying DGS). With these efficiency gains, EPA projected the life-cycle GHG emissions of corn ethanol in 2022 at 21% lower than gasoline.

Our current conditions scenario assesses the life-cycle emissions of corn ethanol at 59,766 g CO_2e/MMBtu. This is a 39% reduction in GHG emissions relative to gasoline; almost twice the reduction developed in the RIA. This scenario assumes ethanol plants use a composite process fuel that reflects today's mix of natural gas, coal, and other fuels used by refineries. The 39% reduction is the industry-wide average GHG reduction for corn ethanol relative to gasoline. However, most refineries today use natural gas as a process fuel. In Table A2, replacing the fuel production emissions in the current conditions scenario with the fuel production emissions in the BAU scenario indicates that the GHG profile of corn ethanol produced in these refineries is 42.6% lower than that of gasoline.

Our BAU scenario assumes a continuation through 2022 of current trends in average corn yields per hectare, process fuel switching from coal to natural gas, and increasing fuel efficiency in heavy-duty trucks. Based on these trends, we project life-cycle GHG emissions for corn ethanol in 2022 at 54,588 g CO_2e/MMBtu. This scenario indicates that even if the ethanol industry does not act to reduce emissions, the GHG profile of corn ethanol will continue to improve. By 2022, the emissions associated with producing and combusting corn ethanol will be, on average, 44.3% lower than the emissions associated with producing and combusting gasoline.

Our HEHC scenario assumes refineries actively reduce their GHG profile. Refineries use sustainably produced biomass as the process fuel, contract with farmers to grow corn using low-emissions practices, and locate CAFOs near refineries. Projected emissions for corn ethanol in 2022 are 27,852 g CO_2e/MMBtu, which is a 71.6% reduction in GHG emissions relative to gasoline. The main source of emissions reductions is the shift to sustainable biomass as the process fuel. While it is not likely the ethanol industry as a whole will undertake these changes, it does highlight the emissions reductions that are technically possible with currently available technologies. Given an appropriate incentive, some refineries will likely undertake these changes. The most likely source of such an incentive are opportunities to participate in new or expanding markets for low-carbon transportation fuels. As noted at the beginning of this paper, a number of these markets are now taking shape outside of the United States.

Finally, in the HEHC scenario refineries achieve an emissions reduction of 4021 g CO_2e/MMBtu by contracting with farmers to grow corn using low-emissions technologies and practices. The practices considered in this scenario are currently available and in use to some degree. Again, given an appropriate incentive, refineries could use such contracts to reduce ethanol's current GHG profile. Subtracting 4021 g CO_2e/MMBtu from the current emissions levels of a 'representative' refinery results in an emissions profile 43.1% lower than that of gasoline. For natural gas-powered refineries, the emissions reduction would be 46.7%.

Conclusions

This paper assesses the current greenhouse gas profile of US corn ethanol and two projected emissions profiles for 2022. The starting point is the GHG life-cycle analysis done by the US Environmental Protection Agency in 2010 for US corn ethanol as part of its Regulatory Impact Analysis (RIA) for the Revised Renewable Fuel Standard (RFS2). In the RIA, EPA projected that in 2022, the life-cycle emissions associated with ethanol would be 21% lower than those of an energy-equivalent quantity of gasoline.

We assess each of the 11 emissions categories in the 2010 EPA LCA in light of new data, technical papers, research studies and other information that have become available since 2010. Aggregated across the 11 categories, we find US corn ethanol is developing along an emissions pathway significantly lower than what EPA projected in 2010. Our analysis indicates the current GHG profile of US corn ethanol is, on average, 39% lower than that of gasoline. For natural gas-powered refineries, this value is

almost 43% lower. Finally, current trends in the ethanol industry and actions refineries could take to reduce emissions offer opportunities to lower the GHG profile of corn ethanol to between 47.0 and 70.0% relative to gasoline.

Our analysis is timely because many countries (e.g. Colombia, Japan, Brazil, Canada and the European Union) are now developing or revising their renewable energy policies. These policies typically require biofuel substitutes for gasoline to reduce GHG emissions by more than 21%. Our results could help position US corn ethanol to compete in these new and growing markets.

Notes

1. The US gasoline supply consists of gasolines imported from many foreign regions and gasolines refined domestically from petroleum extracted from numerous domestic and foreign regions. The gasoline assessed in the RIA is a composite product constructed to represent the 'average' gasoline consumed in the United States in 2005 [1, section 2.5].
2. To help readers quickly compare the methods of the RIA and our study, Appendix Table A1 identifies key differences in data, models, emission factors and other information used in the two studies by emissions source category.
3. To make our results familiar to a wider set of people in other disciplines, Appendix Table A2 presents emissions by source category for the RIA and our three scenarios in both g CO_2e/MMBtu and g CO_2e/MJ.
4. The regional breakdown, in acres, is in Rosenfeld et al. [5; table 2-6, p. 18].
5. ARMS is an annual survey that collects data on the financial condition, production practices, and resource use for US farms. Each ARMS samples about 5000 fields and 30,000 farms that are representative of that year's surveyed commodities.
6. For example, in Appalachia, 95.2% of acres apply nitrogen (N) and the average application rate is 173.01 kg/ha. Multiplying the adoption rate by the application rate gives an effective N application rate across the region of 164.70 kg/ha.
7. Our approach allows us to clearly distinguish between new acres brought into corn production due to increases in ethanol production, acres leaving corn production due to increases in supply of distiller grains and solubles, and the GHG impacts related to each set of acres (i.e. changes in emissions related to changes in farm input use and changes in soil carbon). Additionally, our approach allows us to account for the increase in average corn yields per hectare since 2010.
8. This table is reproduced in Rosenfeld et al. [5, p. 82].
9. MOVES estimates emissions for mobile sources covering a broad range of pollutants, and allows multiple-scale analysis.
10. The term 'sustainably produced biomass' abstracts from several emissions-related issues that could accompany a large-scale increase in the use of biomass as a process fuel by ethanol refineries. For example, LUC and farm input emissions could change if large areas of land are shifted into energy crop production. The nature and GHG intensity of feedstock production geared to supply large quantities of biomass to the ethanol industry would likely vary by region, and even by refinery location. While an analysis is beyond the scope of this paper, we acknowledge that our HEHC scenario is likely a relatively low-emissions case.

Disclosure statement

No potential conflict of interest was reported by the authors.

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Appendix Table A1. Summary of Key Data Sources and Models Used in the Regulatory Impact Analysis (RIA) Life Cycle Analysis and the Current Greenhouse Gas (GHG) Profile.

Source category	RIA [1]	Current GHG profile
General – Global warming potentials (GWPs)	Second Assessment Report (1996) • Methane: 21 • Nitrous oxide: 310	Fourth Assessment Report (2007) • Methane: 25 • Nitrous oxide: 298
Domestic farm inputs and fertilizer Nitrous Oxide (N_2O)	• Fertilizer application rates and fuel Consumption: Forestry and Agricultural Sectoral Optimization Model (FASOM version 2010) • Fertilizer and fuel production Emission factors: The Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation Model (GREET) version 2009 • Fertilizer use emission factors: Daily Century (DAYCENT) Model (version 2010)	• Fertilizer application rates: [6] • Fuel consumption: [7] • Fertilizer and fuel production emission factors: GREET (version) 2015 • Fertilizer use emission factors:[10] • Animal feed co-product credit: GREET (version 2015)
Domestic land use	• Acres: FASOM (version 2010) • Emission factors: DAYCENT Model (version 2010)	• Acres: [12] • Emission rates: Century and Cole Models (version 2015)
Domestic rice methane	• Acres: FASOM (version 2010) • Emission factors: [19]	• Acres: same as [1] • Emission factors: [21]
Domestic livestock	• Change in livestock populations: FASOM (version 2010) • Emission factors: [19]	• Change in livestock populations: same as [1] except poultry • Livestock conventional feed emission Factors: [21] • Emission reductions from Distillers Grains with Solubles as feed: GREET (version 2015)
International livestock	• Populations: Food and Agriculture Policy Research Institute-Center for Agricultural and Rural Development (FAPRI-CARD) (version 2010) • Emission Factors: [10]	• Populations: same as [1] • Emission factors: [10] except for Canada (2016) with a country-specific update
International land-use change	• Acres: FAPRI-CARD (version 2010) • Emission factors: Winrock International (2009)	• Acres: [12]; in two scenarios, acres adjusted with data in [17] • Emission factors: Winrock International (2009), Woods Hole (2010) and California Air Resources Board (CARB) Agricultural - Ecological Zones (AEZ) (2015)

(*continued*)

Appendix Table A1. Continued.

Source category	RIA [1]	Current GHG profile
International farm inputs and fertilizer N_2O	• Acres and production: FAPRI-CARD (version 2010) • Fertilizer application rates: [30] and [31, version 2009] • Fuel use: [34] • Fertilizer and fuel production emission factors: GREET (version 2009) • Fertilizer use emission factors: Methodology similar to domestic	• Acres and production: [12] • Fertilizer application rates: [31, version 2015] • Fuel use: same as [1] • Fertilizer and fuel production emission Factors: GREET (version 2015) • Fertilizer use emission factors: [10]
International rice methane	• Acres: FAPRI-CARD (2010) • Emission factors: [10]	• Acres: same as [1] • Emission factors: same as [1]
Fuel and feedstock transport	• Transport distances: GREET (version 2009) • Emission factors: GREET (version 2009)	• Transport distances: GREET (version 2015) • Emission factors: GREET (version 2015)
Fuel production	• Process energy: GREET (version 2009) • Emission factors: GREET (version 2009)	• Process energy: GREET (version 2015) • Emission factors: GREET (version 2015)
Tailpipe	• Emissions: [39]	• Emissions: GREET (version 2015)

Appendix Table A2. Emissions by scenario and category.

	Estimated Greenhouse Gas (GHG) emissions (in grams carbon dioxide equivalent per million British thermal units)			
Emissions category	RIA (2010)	Current	2022 BAU	2022 HEHC
Domestic farm inputs	10,313	9065	8190	4490
Domestic Land Use Change	−4000	−2038	−2038	−2359
Domestic rice methane	−209	−1013	−1013	−1013
Domestic livestock	−3746	−2463	−2463	−2463
International Land Use Change	31,790	9094	9094	9094
International farm inputs	6601	2217	2217	2217
International rice methane	2089	2482	2482	2482
International livestock	3458	3894	3894	3894
Fuel and feedstock transport	4265	3432	2641	1237
Fuel production	28,000	34,518	31,006	9695
Tailpipe	880	578	578	578
Total	**79,441**	**59,766**	**54,588**	**27,852**
	Estimated GHG emissions (in grams carbon dioxide equivalent per Mega Joule)			
Domestic farm inputs	9.77	8.59	7.76	4.26
Domestic Land Use Change	−3.79	−1.93	−1.93	−2.24
Domestic rice methane	−0.20	−0.96	−0.96	−0.96
Domestic livestock	−3.55	−2.33	−2.33	−2.33
International Land Use Change	30.13	8.62	8.62	8.62
International farm inputs	6.26	2.10	2.10	2.10
International rice methane	1.98	2.35	2.35	2.35
International livestock	3.28	3.69	3.69	3.69
Fuel and feedstock transport	4.04	3.25	2.50	1.17
Fuel production	26.54	32.72	29.39	9.19
Tailpipe	0.83	0.55	0.55	0.55
Total	**75.30**	**56.65**	**51.74**	**26.40**

Modeling and Analysis

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Retrospective analysis of the U.S. corn ethanol industry for 2005–2019: implications for greenhouse gas emission reductions

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Abstract: Since 2000, corn ethanol production in the USA has increased significantly – from 1.6 to 15 billion gallons (6.1 to 57 billion liters) – due to supportive biofuel policies. In this study, we conduct a retrospective analysis of the changes in US corn ethanol greenhouse gas emission intensity, sometimes known as carbon intensity (CI), over the 15 years from 2005 to 2019. Our analysis shows a significant decrease in CI: from 58 to 45 gCO_2e/MJ of corn ethanol (a 23% reduction). This is due to several factors. Corn grain yield has increased continuously, reaching 168 bushels/acre (10.5 metric tons/ha, a 15% increase) while fertilizer inputs per acre have remained constant, resulting in decreased intensities of fertilizer inputs (e.g., 7% and 18% reduction in nitrogen and potash use per bushel of corn grain harvested, respectively). A 6.5% increase in ethanol yield, from 2.70 to 2.86 gal/bushel corn (0.402 to 0.427 L kg^{-1} corn), and a 24% reduction in ethanol plant energy use, from 32 000 to 25 000 Btu/gal ethanol (9.0 to 6.9 MJ L^{-1} ethanol) also helped reduce the CI. The total GHG emission reduction benefits through the reduction in the CI and increased ethanol production volume are estimated at 140 million metric tons (MMT) from 2005 to 2019 in the ethanol industry. Displacement of petroleum gasoline by corn ethanol in the transportation fuel market resulted in a total GHG emission reduction benefit of 544 MMT CO_2e during the period 2005 to 2019. © 2021 Argonne National Laboratory. *Biofuels, Bioproducts and Biorefining* published by Society of Industrial Chemistry and John Wiley & Sons Ltd

Supporting information may be found in the online version of this article.

Key words: corn ethanol; carbon intensity; life-cycle analysis; greenhouse gas emissions; well-to-wheels

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Introduction

Corn ethanol plays an important role in enhancing energy security and the rural economy while contributing to decarbonizing the transportation sector in the USA. Ethanol accounted for more than 10% of the US gasoline market share in 2019.[1] Corn ethanol production in the USA has increased from 1.6 billion gallons per year (BGY) (6.1 billion liters per year [BLY]) in 2000 to more than 15 BGY (57 BLY) in 2019[2] with the help of supportive biofuel policies such as the US Environmental Protection Agency's (EPA's) Renewable Fuel Standard (RFS) and California's Low-Carbon Fuel Standard (LCFS).

The RFS and LCFS programs evaluate the life-cycle greenhouse gas (GHG) emissions of fuel production pathways to quantify the GHG emission reduction benefits of using renewable fuels. Life-cycle analysis (LCA) is used to quantify the life cycle GHG emissions of fuels, the metric for comparing relative GHG emission impacts among different fuel production pathways. The RFS and LCFS evaluate GHG emissions of fuels on a full life-cycle basis. These life-cycle GHG emissions are sometimes referred to as the fuel's carbon intensity (CI). For example, RFS classifies corn ethanol production pathways in the D6 category, which means the life cycle GHG emissions are expected to be 20% lower than those of the baseline gasoline.[3] California's LCFS, on the other hand, estimates the CI of each renewable fuel production pathway to estimate the actual reductions in GHG emissions made by displacing the petroleum fuels. For example, Rosenfeld *et al.*[4] presented that in the first quarter of 2019, LCFS-certified ethanol production pathways had an average CI of 66 gCO_2e/MJ, including land-use change (LUC) GHG emissions, which is 35% lower than that of the California gasoline blendstock (100.82 gCO_2e/MJ).[5]

The corn ethanol production pathway, including both corn farming and biorefineries, has substantially evolved in the past two decades. From 2000 to 2019, US corn production ranged from a low of 9.0 billion bushels (230 million metric tons [MMT]) in 2002 to a high of 15.1 billion bushels (380 MMT) in 2016, with 13.6 billion bushels (350 MMT) produced in 2019. Since the enactment of the Energy Independence and Security Act in 2007,[6] corn used for ethanol production increased to about 5.3 billion bushels (130 MMT) in 2015, which is about 40% of the corn grain produced in the USA.[7] In addition, corn yield per hectare has grown continuously, while chemical inputs per hectare remain constant.

Biorefineries have also increased the yield of ethanol per unit of corn while producing co-products. Along with distillers grains with solubles (DGS), an important animal feed, more facilities now recover corn oil and CO_2. This helps increase revenue while potentially reducing the emission burdens of ethanol production.

Previous LCA studies have demonstrated the GHG emission reduction benefits of corn ethanol as a gasoline alternative. The EPA's LCA study for RFS in 2010[3] showed a reduction of 21% in GHG emissions by corn ethanol. Wang *et al.*[8] evaluated the CI of corn ethanol and other cellulosic ethanol production pathways, then incorporated the ethanol production pathways into the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET)® model developed by Argonne National Laboratory (Argonne).[9] The California Air Resources Board (CARB) developed CA-GREET from Argonne's base GREET model for LCFS compliance. Results from Wang *et al.*[8] in 2012 have been the basis for developing default LCFS CIs for corn ethanol.

Additional LCA studies evaluating the CI of corn ethanol have confirmed that the use of corn ethanol results in GHG emission reductions. Two reports by Life Cycle Associates in 2014 and 2021[10,11] evaluated the CIs of biofuels, including US corn ethanol, using the GREET model. The 2014 report estimated the CI of corn ethanol to be 65.5 gCO_2e/MJ, including LUC GHG emissions of 9.0 gCO_2e/MJ.[10] The 2021 report[11] calculated the CI of corn ethanol to be 53.2 gCO_2e/MJ (including LUC GHG emissions of 7.4 gCO_2e/MJ) in 2020. The US Department of Agriculture (USDA) published several reports on the CI of US corn ethanol using the GREET model.[4,12–14] These reports, with a LUC GHG value of 6.7 gCO_2e/MJ, show a CI of 52.8–56.6 gCO_2e/MJ for corn ethanol between 2014 and 2019, and project a CI of 47.9–51.7 gCO_2e/MJ for 2022. Pereira *et al.*[15] compared the CIs of corn ethanol in three major regions (US, Europe, and Canada) using representative public LCA tools (GREET, BioGrace, and GHGenius, respectively), and found CIs of 57.7, 43.4, and 61.9 gCO_2e/MJ (including LUC) in the US, Europe, and Canada, respectively. Most recently, Scully *et al.*[16] used historical versions of the GREET model to show the changes in the CI of US corn ethanol over time. In 2020, they estimated a CI of 51.4 gCO_2e/MJ, including a LUC GHG emission of 3.9 gCO_2e/MJ.

There have been continuous requests to update LCA results with primary data for corn ethanol that reflect the improvements in this industry.[13] The objective of this study is to evaluate the historic trends in corn ethanol CI over the 15 years from 2005 to 2019, using primary data for US corn farming and ethanol production with survey data collected by USDA and the ethanol industry. This retrospective LCA helps demonstrate the impacts on corn ethanol CI trends made by key parameters such as corn and ethanol yield, fertilizer use, and energy consumption in both corn farming and

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biorefineries. With an understanding of these impacts, GHG reductions by the corn ethanol industry made in the past and potential reductions in the future can be better assessed. All the collected data from this study are also used to update key corn ethanol parameters in GREET 2021, to be released in October 2021 (https://greet.es.anl.gov/).

Methodology

System boundary

Having a consistent, complete system boundary is one of the important factors for a reliable LCA of biofuels. As presented in Fig. 1, there are four major stages – corn farming, ethanol production, ethanol transportation and distribution (T&D), and ethanol combustion – in the corn ethanol production supply chain. We account for all GHG emissions (i.e., CO_2, CH_4, and N_2O) for each stage as well as upstream GHG emissions of the inputs to each stage (e.g., electricity, natural gas, fertilizer, etc.).

The corn farming stage accounts for GHG emissions from farm manufacturing (upstream) inputs as well as corn growth, where the various farming inputs, such as fertilizers/chemicals, on-farm fuels for agricultural equipment, and electricity, are utilized.

In the ethanol production stage, biorefineries convert corn into ethanol via fermentation, with the help of enzymes/yeast. Fermentation, downstream distillation, and DGS drying all require a large amount of steam and heat that are produced primarily from natural gas. A small amount of electricity is used for plant operation. During the conversion process, biorefineries generate DGS, an animal feed. Many ethanol plants now recover corn oil and CO_2 to increase revenue. Corn oil is sold for production of biodiesel and renewable diesel, while CO_2 can be used mainly for food processing and beverage production. Therefore, the impact of the production of co-products should be accounted for.

The ethanol T&D stage includes transporting ethanol from the biorefinery to the end use (pump) via trucks and trains. The ethanol combustion stage accounts for ethanol combustion emissions during vehicle operation. However, since the CO_2 emissions from ethanol combustion are offset by a corn plant uptake of CO_2 during growth, biogenic CO_2 emissions from ethanol combustion are considered to be zero with the carbon neutrality assumption. The CH_4 and N_2O emissions of ethanol combustion are accounted for.

The functional unit in this study is a megajoule (MJ) of ethanol produced and used. Greenhouse gas emissions are expressed in terms of grams (g) of carbon dioxide equivalent (CO_2e) using global warming potentials (GWPs) with a 100-year time horizon based on the Fifth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC).[17]

In this study, we used corn farming data and biorefinery survey results for the first two stages, marked in red in Fig. 1, which are explained in the following sections in detail. For other stages and parameters, we relied on the default parameters that the GREET model employs.[9] The GREET model enables the estimation of the upstream emissions of various inputs for corn farming and biorefineries and emissions associated with T&D and fuel combustion in vehicles. We assumed that the co-products displace their counterparts. Note that all the results presented in this study are based on undenatured ethanol.

Corn farming

State-level estimates of key parameters affecting the CI of corn farming (Table 1) were based on data from the USDA's

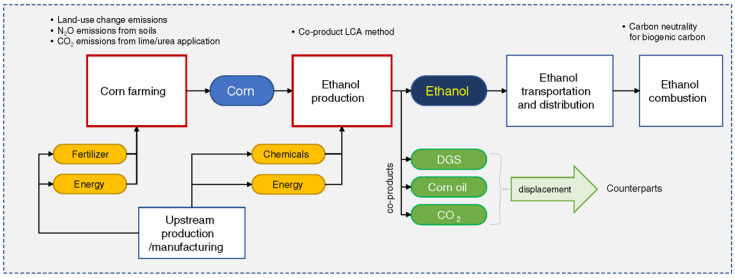


Figure 1. The LCA system boundary and major parameters for corn ethanol.

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Table 1. Data source, regional, and temporal coverage of the state-level estimates of key parameters for corn farming.

Spatial coverage	Data (and source) used to derive key parameters*	Unit	Year															Parameter	Unit
			2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019		
Conterminous 41 states**	Grain yield (NASS)	bu/ac																Grain yield	bu/ac
Selected 15–19 states***	N, P_2O_5 and K_2O used on corn, rate per fertilized acre receiving the nutrients (ERS)****	lb/ac*****																N, P_2O_5, and K_2O use	lb/bu
	Corn planted area receiving each fertilizer (NASS)	%																	
	Corn planted area (NASS)	ac																	
	Grain production (NASS)	bu																	

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Table 1. (Continued)

Spatial coverage	Data (and source) used to derive key parameters*	Unit	Year														Parameter	Unit
			2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	
Nine states****	Grain yield (NASS)	bu/ac																
	Diesel (OCE and ARMS)	gal/ac															Diesel	gal/bu
	Gasoline (OCE and ARMS)	gal/ac															Gasoline	gal/bu
	Liquefied petroleum gas (OCE and ARMS)	gal/ac															LPG	gal/bu
	Electricity (OCE and ARMS)	kWh/ac															Electricity	kWh/bu
	Natural gas (OCE and ARMS)	ft^3/ac															Natural gas	ft^3/bu
	Lime (OCE)	lb/ac															Lime	lb/bu
	Chemicals (OCE)	lb/ac															Chemicals	lb/bu

Gray boxes indicate the years for which data is available.
*All the data published by NASS is accessible through Quick Stats (https://quickstats.nass.usda.gov/).[18]
**Among the 48 conterminous states. 41 states have reported corn grain yields for 2005–2019.
***The states selected in the ERS dataset for annual fertilizer use on corn are shown in Fig. S1.
****The nine states are Illinois, Indiana, Iowa, Minnesota, Nebraska, Ohio, Michigan, South Dakota, and Wisconsin (Fig. S1), which account for more than 70% of US total corn grain production in 2019.
*****The ERS dataset includes either actual pounds or percentage analysis of N, P_2O_5, and K_2O from custom-applied nutrients and fertilizers and commercially prepared manure or compost, but excludes unprocessed manure.[15] As a result, the rates could be underestimated in the states where manure application is often practiced, such as Minnesota and Wisconsin, compared with a survey that excluded manured fields.[20]

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major survey programs, the National Agricultural Statistics Service (NASS)[18] the Economic Research Service (ERS),[21] and the Office of the Chief Economist (OCE) reports.[22,23] More details on the data sources can be found in the supporting information (SI).

Corn yield per area unit is used to calculate the farming inputs per bushel or per weight (a bushel of corn weighs 56 lb or 25.4 kg) of corn grain. The yield data coupled with the nitrogen (N) content in corn biomass and the harvest index provide the N in crop residues left in the field after harvest, which is one of the main sources for nitrous oxide (N_2O) emissions from soils. In this analysis, we extracted the historical corn yield data from the NASS Agricultural Survey, which reports state-level grain yields per harvested area in bushels/acre. The N_2O emissions from crop residue N were estimated by using the IPCC methodologies described in IPCC[24] and Liu *et al.*[25]

In this study, we included farming inputs such as N (e.g., urea), P (in the form of phosphate, P_2O_5), K (in the form of potash, K_2O), lime, and herbicides/pesticides. We extracted the rates of NPK used on corn (per fertilized area receiving the nutrients) and the percent of corn area receiving the NPK from the ERS dataset for annual fertilizer use on corn, which is based on NASS's Agricultural Resource Management Survey (ARMS) Phase II (details in SI 1.1). By coupling these data with the state-level corn planted area (from NASS), we calculated the total usage of NPK fertilizers for corn production in each state. Finally, we divided use by the state-level grain production (from NASS) to estimate the nutrient input intensities (lb nutrients/bushel of corn grain) (Table 1). We relied on the lime and chemicals use available from OCE reports, in which the energy balance of corn ethanol has been analyzed for the major nine corn-producing states (details in SI 1.1).

The estimates of nutrient / chemical input intensities were then multiplied by the GHG intensities of fertilizer / chemical manufacturing in the GREET model.[9] In particular, NPK intensities were allocated to different fertilizer types based on the US consumption of fertilizers in 2010[21] to assign a specific GHG intensity to the production of each fertilizer type (e.g., ammonia production emits 2620 kg CO_2e/metric ton, while urea emits 1219 kg CO_2e/metric ton). The usage share of each fertilizer type was tracked by ERS until 2015. For example, the share of ammonia-N (anhydrous plus aqua) in total N fertilizer usage decreased by 3% from 2010 to 2015, while that of urea-N increased by 5% for the same period. We did not consider the 2015 shares for this analysis, because the shares are not specific to corn farming but to all crops growing in the USA. Instead, the shares of fertilizer types specific to corn farming from the 2010 data, as in GREET, were used. We also employed the rates of N fertilizer and urea / lime applications to calculate fertilizer-driven N_2O and CO_2 emissions by using empirical emission factors.[26,27]

Various farming operations such as tilling fields, planting and harvesting biomass, and drying corn grain require energy: diesel, gasoline, liquefied petroleum gas (LPG), electricity, and natural gas. Since the early 1990s, on-farm energy consumption specific to corn farming has been periodically surveyed through ARMS and summarized in the OCE reports. For this study, we used the data for nine states to calculate farm energy consumption. Note that the estimates for the most recent year of data for corn (2016) were calculated by using the state-level fuel costs for corn production available from the ARMS Phase III dataset farm business survey[21] and the fuel and electricity prices reported by the US Energy Information Administration (EIA).[28] For example, as of 2016, the electricity cost for corn farming in Illinois was $2.88/acre ($7.11/ha) from the ARMS dataset[21] and the residential price of electricity in the state was 12.5 cents/kWh (3.5 cents/MJ) from EIA data,[28] resulting in the estimate of 23 kWh/acre (205 MJ/ha).

Finally, we calculated the average emissions of farming inputs per bushel of corn grain by using corn production in each state as a weighting factor to represent the farming CIs at the national level. We interpolated weighted averages to fill in any missing estimates in years when records / data were not available and used for analyzing corn ethanol CI (Table S1). We assumed that the diesel fuel and gasoline consumed in corn farming are related to the area of field operations rather than corn yields harvested. Diesel and gasoline use (gal/ac) were first interpolated between years and then divided by bushels of corn grain. This process is different from the interpolation of the NPK use and other fuel types, such as LPG, electricity, and natural gas, which are first divided by yield and then interpolated between years (Table S1). Because of this interpolation approach, and the lack of data for corn farming in 2012 (Table 1), when a severe to extreme drought caused a loss of more than one quarter of the year's corn production,[29] our analysis reflects the drought's impacts on diesel and gasoline use only.

Corn ethanol production

Christianson (www.christiansoncpa.com), a corn ethanol benchmarking and agricultural consulting company, has been conducting quarterly surveys of dry mill corn ethanol facilities every year since 2003. Dry mills produce 91% of US fuel ethanol (the remaining 9% is from wet mills).[30] The survey covers ethanol yields (with corn inputs and ethanol production), all energy inputs by type (natural gas, coal, and electricity), chemical inputs, the yields of co-products,

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and financial information. For this study, Christianson agreed to provide Argonne its annual corn ethanol industry benchmarking statistics for 2005 to 2019. Argonne implemented the Christianson statistical data into the GREET model to evaluate the impact of the changes in the inputs / outputs of corn ethanol production facilities. Figure S2 in the supplementary material presents the share of total ethanol production of the plants in Christianson's benchmark database out of the total ethanol volume in the USA. The survey covers 40% (65 facilities) of ethanol production in 2019 and the minimum coverage of 22% (25 facilities) in 2008. While the survey has limited coverage, especially in earlier years, coverage of later years has been adequate. The dataset (ethanol yield, DGS and corn oil production, and energy usage) was further verified by an independent Argonne survey, which covered 66 US facilities in 2017.[31]

In addition to corn ethanol, biorefineries produce other products, such as DGS, syrup, corn oil, and CO_2. Distillers grains with solubles, a feed for livestock, comes in three types: DDGS (dry DGS), WDGS (wet DGS), and MWDGS (modified wet DGS), depending on the preferred end use,[32] and the benchmarking database has information on the amount of each DGS type. The benchmarking database also includes information about syrup and corn oil production (lb/gal ethanol) and the amount of CO_2 captured (lb/gal ethanol).

In this study, we assumed that DGS and syrup are used to displace conventional animal feeds (corn, soybean, and urea).[8,33] As corn oil can be used for other fuel production, it is assumed that corn oil displaces soy oil for the production of biodiesel and renewable diesel.[9] The GREET model estimates emissions credits from the displaced conventional animal feeds or soy oil by ethanol co-products, which helps to reduce the emissions burden of ethanol production. In this study, we consider CO_2 to be a byproduct that does not impact the emission burdens of ethanol. Even though CO_2 can be considered as a co-product potentially displacing conventional CO_2 production, current merchant CO_2 is mainly supported by the facilities generating CO_2 as a byproduct (e.g., during ammonia or hydrogen production). Thus, the emission reduction benefits of captured CO_2 in ethanol plants may be limited. In cases in which CO_2 from biorefineries is captured and sequestered, we expect corn ethanol may present an opportunity for further reductions in GHG emissions.[34] The CO_2 captured from biorefineries can also be used for fuels and chemicals production.[35]

For chemical inputs such as enzymes and yeast, we used the GREET default values, which rely on Wang *et al.*[8] instead of using the Christianson benchmarking results. This is because the benchmarking statistics for these inputs are presented in terms of $/gallon ethanol, which cannot be converted reliably into the amount of chemical inputs. Note that the total impacts of the biorefinery chemical inputs on corn ethanol GHG emissions are estimated at about 1.8 gCO_2e/MJ. Although the impact is not negligible, the impact of the changes from 2005 to 2019 in chemical inputs should be small. For example, a 10% change in these chemicals inputs results in a change of less than 0.2 gCO_2e/MJ for the ethanol CI.

Results and discussion

Corn farming and ethanol production trends

Corn yield has grown continuously, from 119 bushels/acre (7.4 metric tons/ha) in 1990 to 168 bushels/acre (10.5 metric tons/ha) in 2019 (Fig. 2(a)). Except in the drought year, 2012, corn yield has been well above 140 bushels/acre (8.8 metric tons/ha) for the past 15 years. Meanwhile, fertilizer inputs per acre remained constant, resulting in decreasing intensities of fertilizer/chemical inputs: for example, 7% and 18% reduction in N and potash uses per bushel of corn grain from 2005 to 2019, respectively (Fig. 2(b)). Similarly, farming energy use per bushel of corn has been slightly reduced from 9.7 to 8.4 thousand Btu (0.40 to 0.35 MJ/kg; a 14% reduction) (Fig. 2(c)). The sudden increase in diesel and gasoline use in 2012 was due to our interpolation approach and to the large decrease in corn yield as stated above. Using a three-year moving-average yield from 2011 to 2013 for 2012, we estimated a CI reduction of 0.23 gCO_2e/MJ in 2012 for corn ethanol (limited to 2012 only).

Another significant change over the 15 years is the continuous increase in the ethanol yield (Fig. 3(a)). From 2005 to 2019, the ethanol yield has increased by 6.5%. In 2005, the weighted average ethanol yield was estimated at 2.70 gal/bushel (0.402 L kg^{-1}), which increased to 2.86 gal/bushel (0.427 L kg^{-1}) in 2019. The distribution (P10 to P90) in Fig. 3(a) shows that the ethanol industry in general has improved ethanol yield. The lowest 10 percentiles in 2019 represents a higher ethanol yield than the weighted average value in 2005. The ethanol yield in each year also shows a variation of around 10% of the average. In 2005 and 2019, the variation ranged from 2.53–2.80 gal/bushel (0.377–0.417 L kg^{-1}) in 2005 to 2.74–2.95 gal/bushel (0.408–0.440 L kg^{-1}) in 2019. The variation in 2019 may mean there is still room to improve yield if low-yield plants can be improved to reach the yield of high-yield plants.

Ethanol plants have made efforts to reduce energy consumption. From 2005 to 2019, a 24% reduction in

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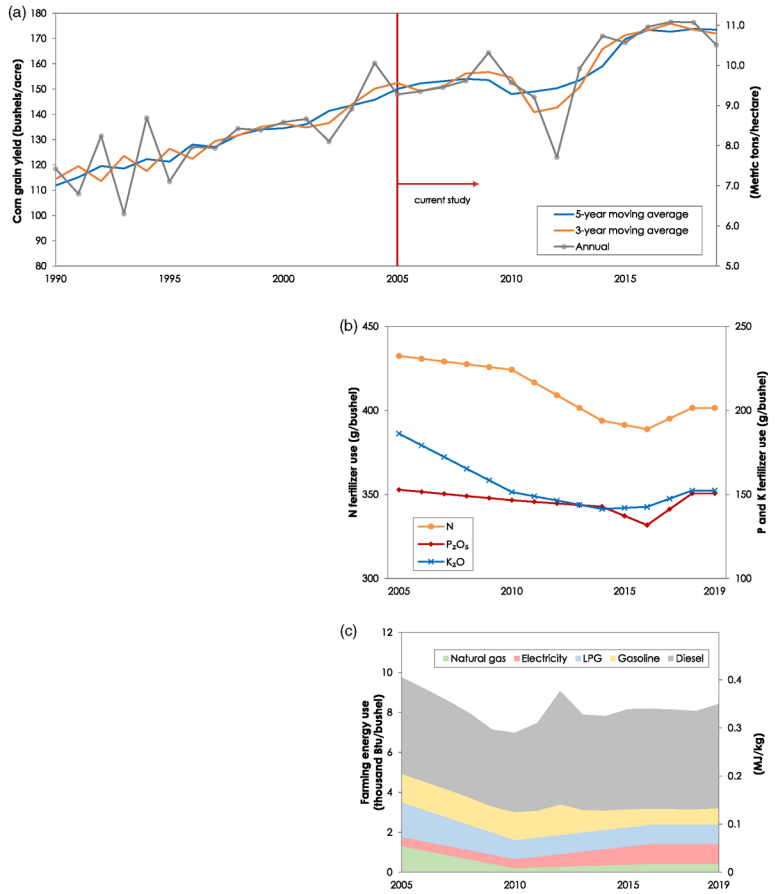


Figure 2. Historical trends of US corn farming parameters from 2005 to 2019. (a) US corn grain yield in bushels/acre with annual, 3- and 5-year moving average values, (b) corn farming fertilizer use in g of nutrient/bushel, and (c) corn farming energy use in thousand Btu (low heating value)/bushel. Note that the drought of 2012 caused a huge decrease in corn yield.

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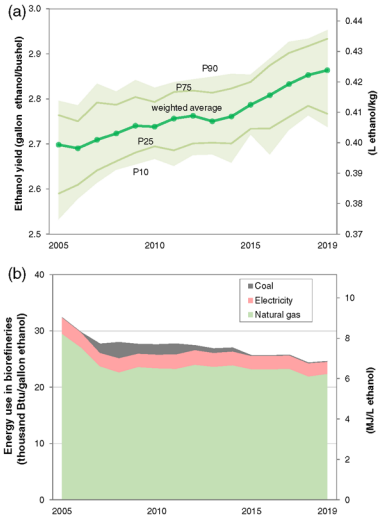


Figure 3. Historical trends of US corn ethanol production parameters from 2005 to 2019. (a) Corn ethanol yield in gallons of undenatured ethanol/bushel) and (b) energy use in biorefineries in thousand Btu (lower heating value)/gallon of ethanol.

energy inputs has been achieved: from 32 000 to 25 000 Btu/gal ethanol or 9.0 to 6.9 MJ L^{-1} ethanol (Fig. 3(b)). At the same time DGS production has decreased by 21%, from 5.1 to 4.0 dry lb DGS/gal ethanol (0.61 to 0.48 kg L^{-1}), from 2005 to 2019 (Fig. S3). This is mainly because of the increase in ethanol yield as well as other new co-products (corn syrup and corn oil). For example, corn syrup has been produced by ethanol plants since 2008 (Fig. S3), and corn oil production started in 2008 and doubled by 2019 (Fig. S4).

During the fermentation process, high-purity CO_2 is generated, which can be captured and used for other purposes. Ethanol plants in the USA have been a major merchant CO_2 supplier.[36] As of 2013, more than 30% of ethanol production plants captured CO_2 (Fig. S5). Carbon dioxide capture rates have also increased by 63% from 2005 to 2019: from 2.3 to 3.7 lb CO_2/gal ethanol (0.27 in to 0.45 kg L^{-1}).

Carbon intensities of corn ethanol

Figure 4 presents the life-cycle GHG emissions (CIs) of US corn ethanol, showing the contribution of each stage for the 15 years from 2005 to 2019 without considering the LUC impact (which is 7.4 gCO_2e/MJ from GREET modeling; see the following section). The major GHG emission contributors are corn farming and ethanol production. In 2019, corn farming (energy and fertilizers/chemicals) and ethanol production contributed 95% of the total GHG emissions (50% and 45%, respectively), while transportation (for both feedstock and fuel) contributed 5%. Since the system produces co-products such as DGS, syrup, and corn oil, there is a displacement emissions credit, which is estimated at −12 gCO_2e/MJ for 2019. The emission credits from corn oil and syrup production have contributed 3–6% and 1–3%, respectively, since 2011, and the largest GHG credit is from DGS.

Due to significant reductions in the inputs for the farming and ethanol production processes, corn ethanol CIs (black bars) have been reduced by 23% (14 gCO_2e/MJ), from 58 gCO_2e/MJ in 2005 to 45 gCO_2e/MJ in 2019. Specifically, the ethanol production stage shows a 11 gCO_2e/MJ reduction during our 15 year period, in which ethanol yield has increased by 6.5% (Fig. 3(a)), and energy use has decreased by 24% (Fig. 3(b)). Ethanol yield determines the amount of corn used for ethanol production. Thus, an increase in ethanol yield helps reduce the emissions of corn production per MJ of ethanol. Reduction in natural gas use in ethanol plants results in lowered ethanol CIs from both reduced natural gas combustion emissions and upstream emissions (natural gas recovery and transportation). We identified that natural gas use in ethanol plants is subject to large variations, about ±40% of the median natural gas use in 2019, which means that there is the potential to further reduce GHG emissions if high natural gas consuming facilities can improve their efficiencies to levels closer to those of the low natural gas consuming ones. In addition, a switch to renewable energy sources can further reduce ethanol plant CIs. For example, using renewable natural gas produced from organic waste materials, such as food waste, animal waste, and wastewater sludge, can be an alternative option for meeting the heat demand for ethanol production with reduced CIs for ethanol.

Corn-farming-related GHG emissions also show reductions over time. From 2005 to 2019, GHG emissions from fertilizers / chemicals and farming energy consumption decreased 4.1 and 0.8 gCO_2e/MJ, respectively. Note that a portion of emissions reduction can be attributed to the increase in ethanol yield (1.5 and 0.22 gCO_2e/MJ for fertilizers/chemicals and farming energy, respectively).

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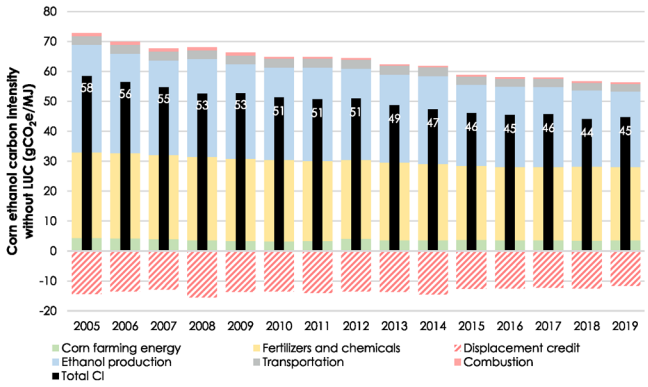


Figure 4. Carbon intensity (gCO_2e/MJ undenatured ethanol) of corn ethanol without LUC for 2005–2019.

Co-products can displace their counterparts, which can indirectly reduce the CIs of corn ethanol. We observe that the red hatched bars in Fig. 4 indicate an increase from −14 to −12 gCO_2e/MJ from 2005 to 2019 because of reductions in DGS yield per gallon of ethanol. As mentioned earlier, higher ethanol yield and corn oil production have a reduced DGS yield over time, which impacts the corn CIs.

Although most reductions in CI can be attributed mainly to improvements in farming and ethanol production, upstream processes also have been improved. For example, electricity use in 2019 led to much lower emissions (449 gCO_2e/kWh [125 gCO_2e/MJ]) than in 2005 (722 gCO_2e/kWh [201 gCO_2e/MJ]).[9]

The CARB has reported the average CI of ethanol certified by LCFS every quarter since 2011.[37] Although the comparison of absolute CI values between the CARB-reported CIs and those in the current study may not be appropriate, due to potential plant overlaps in the CARB and the Christianson databases and different considerations of LCA between CARB and this study, a similar trend can be found (Fig. S6). Except for the sudden drop in LCFS's CI in 2019, reductions in CI from 2011 to 2018 were estimated at 15% and 13%, respectively, by the CARB's database and the current study (when LUC is excluded in both cases). Rosenfeld *et al.*[4] investigated the technologies that help reduce the CI and provided the level of CI reduction through each strategy. They also provided the state-specific CIs for LCFS, which presents regional variations in the corn ethanol CI.

Land use change

The LUC GHG emissions from large-scale corn production for corn ethanol have been simulated since 2008. Early studies showed extremely high LUC emissions (e.g., Searchinger *et al.*[38]), and recent studies show significantly lower LUC emissions (Fig. 5). The downtrend in simulated LUC emissions is a result of better developed and calibrated economic models and better modeling of GHG emissions from LUC. Economic models such as the Global Trade Analysis Project (GTAP) model are much improved in addressing land intensification (i.e., existing lands are managed to be more productive) versus land extensification (i.e., croplands extend into new areas of pasture and forest),[39] crop yield increases over time, crop yield differentials in existing croplands and in newly cultivated croplands, double cropping in regions such as Asia, availability and restriction of certain land conversions (e.g., restriction of public forest land for conversion to croplands), price elasticities for crop yield responses, and food demand responses to price changes. For GHG modeling of LUC, models have been improved, with better spatial and temporal resolutions.

The GREET model estimates a LUC GHG emission rate of 7.4 g CO_2e/MJ for US corn ethanol by using Argonne's Carbon Calculator for Land Use and Land Management Change from Biofuels Production (CCLUB).[50] While relying on LUC results from the improved GTAP versions, CCLUB

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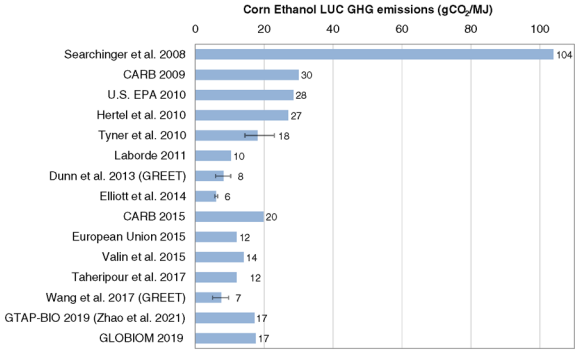


Figure 5. Trend of simulated LUC GHG emissions for US corn ethanol.[39–52] For GTAP-BIO 2019 (Zhao *et al.* 2021[52]) and GLOBIOM 2019, LUC values calculated for corn ethanol-derived jet fuels in ICAO[53] were converted into per-MJ of ethanol. The error bars reflect maximum and minimum values in individual studies.

has developed GHG emission results from GTAP LUC results by adopting detailed modeling results with a process-based model of soil carbon changes, which are an outcome of the modeling's inclusion of the effects of management practices (i.e., tillage) and assumptions that are spatially explicit (e.g., US county-level crop yields).[53]

Aggregate GHG emission reductions for corn ethanol

Reductions in corn ethanol CI, together with expanded ethanol production volume, result in significant emission reduction benefits. In 2005, undenatured ethanol production was estimated at 3.8 BGY (14 BLY),[2] with a CI value of 58 g/MJ (Fig. 4). For the 2005 ethanol production volume level, accumulated emission reduction benefits of the ethanol industry, due to the decrease in CI of corn ethanol from 2005 to 2019, is estimated at 39 MMT CO_2e (Fig. 6). Ethanol production in the USA has also gradually increased, with fuel ethanol production in 2019 reaching 16 BGY (59 BLY). Additional emission reduction benefits through ethanol production expansion are 101 MMT CO_2e from 2005 through 2019. Note that the individual CI values in Fig. 4, plus the LUC value of 7.4 g/MJ (Wang *et al.*[8]) in Fig. 5, were used to estimate the aggregate GHG emission reductions of the ethanol industry from 2005 to 2019.

The reduction in the 58 gCO_2e/MJ CI of corn ethanol in 2005 to 45 g/MJ in 2019 (plus the LUC value of 7.4 g/MJ)

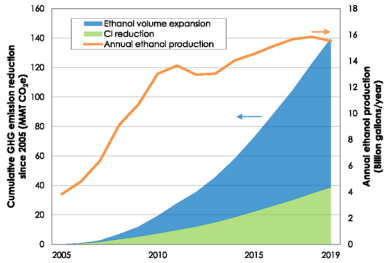


Figure 6. Cumulative GHG emission reduction benefits (area) of the corn ethanol industry from 2005 through 2019 (in MMT CO_2e) through CI reduction and ethanol volume expansion, with annual ethanol production (curve). Emission reduction benefits are estimated using the CI in Fig. 4 plus LUC emissions of 7.4 g/MJ from GREET.

provides significant GHG emission reductions compared to the CI of 93 gCO_2e/MJ for the US average petroleum gasoline blendstock. The displacement of gasoline by corn ethanol on an energy-equivalent basis from 2005 to 2019 has resulted in a cumulative GHG emissions reduction of 544 MMT CO_2e.

There has been a growing interest in further reducing the overall CI of crop-based biofuels by cutting down the

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GHG emissions of biofuel feedstock, which correlates significantly with agronomic practices and chemical and energy inputs in individual farms. Proposals are being made about incentivizing low-carbon biofuel feedstocks in US fuel regulatory programs to promote sustainable farming practices. This will offer further opportunities to advance the sustainability of farming and reduce biofuel CIs.[25]

Conclusions

Corn ethanol production in the USA quadrupled from 2005 to 2019, and US corn farming continues to increase yield. Ethanol biorefinery plants have employed technologies to increase ethanol yield, reduce energy use, and add extra by-products. These trends certainly help reduce the GHG emissions of corn ethanol. We evaluated the downward trend in US corn ethanol CI for 15 years, using primary data of corn farming and ethanol production from the USDA and the ethanol industry. Our study shows that while the corn ethanol industry has experienced significant volume expansion, it has reduced the GHG intensity of corn ethanol through improved US corn farming and ethanol biorefinery operations. Corn yield has increased, and chemical and energy use intensities of corn farming have decreased. In ethanol biorefineries, ethanol yield has increased, and energy use has decreased significantly. In addition, by-products such as corn oil, CO_2, and DGS are produced. These improvements have helped reduce the CI of US corn ethanol by 14 gCO_2e/MJ – from 58 gCO_2e/MJ in 2005 to 45 gCO_2e/MJ in 2019. Ethanol plants have reduced ethanol production emissions by 30% (or 11 gCO_2e/MJ) over the 15-year period, mainly by reducing the energy inputs per unit of ethanol produced. Corn farming reduced chemical and energy input intensities, which contributes to a 17% reduction in farming-related emissions (4.9 gCO_2e/MJ).

From the reduction in corn ethanol GHG emission intensity and ethanol volume expansion, we estimate that the ethanol industry has achieved an additional 140 MMT cumulative GHG emission reduction from 2005 to 2019. The ethanol produced in our 15 years has been introduced to the transportation sector to displace petroleum gasoline. With the displacement, on the LCA basis, corn ethanol has helped the US transportation sector reduce GHG emissions by 544 MMT over the period.

Additional measures exist to reduce corn ethanol GHG emissions further. In the farming stage, sustainable farming practices such as no-till and cover crops can help reduce fertilizer inputs and increase soil organic carbon content. In ethanol biorefineries, fermentation CO_2 can be captured and sequestered, and fossil natural gas can be replaced with renewable natural gas and biomass gasification. Biofuels, including corn ethanol, can play a critical role in the US desire for deep de-carbonization of its economy.

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Uisung Lee

Dr. Uisung Lee is an energy systems analyst at Argonne National Laboratory. His research mainly focuses on evaluating the environmental impact of various energy systems including CO_2 utilization, waste-to-energy, sustainable fuels, and water stress.



Hoyoung Kwon

Dr. Hoyoung Kwon is a principal environmental scientist at Argonne National Laboratory. His research has focused on developing modeling frameworks where process-based models are coupled with multi-scale spatiotemporal databases as a practical means to provide decision makers with better recommendations for sustainable land use and management practices.



May Wu

Dr. May Wu is a principal environmental system scientist at Argonne National Laboratory. Her research interests are water availability, water footprint, and the impact of water use on water quality in biofuel production. Wu has 25 years of experience, 60+ publications, and a PhD in environmental engineering and environmental toxicology from Michigan State University.



Michael Wang

Dr. Michael Wang is the director of the systems assessment center at Argonne National Laboratory. He has been leading the development of the GREET LCA model at the Laboratory. He has done extensive LCA of biofuels over the past 25 years.

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Senator DUCKWORTH. Thank you.

These studies confirm what we already know: American grown, blended biofuels have been reducing GHG emissions for years, and the RFS has played an integral part in these efforts.

I am out of time.

Thank you, Mr. Chairman.

Senator CARPER. All right. Thank you, thanks so much.

Senator Ernst, you have been patient, but Senator Stabenow has been patient as well on Webex. If you don't mind, I am going to let her go first, and then you are immediately right after her. Thank you for your patience.

Senator Stabenow, you are there?

Senator STABENOW. I am, Mr. Chairman, and thank you to Senator Ernst. I appreciate so much working with her on these issues. I appreciate very much your doing this hearing.

I want to take just a step back, way back, for a moment, and kind of frame this. I think this has been framed as big refiners, small refiners, and so on. This is really about whether we are going to continue the dirtiest kind of fuel or have cleaner fuels.

If you go back 100 years, actually, Henry Ford and Thomas Edison first tried to do a vehicle with a battery but could not get government support to help them create the innovation. Two years later, the biggest permanent tax credits for oil and gas were embedded in our Federal tax code, and they have been there 100 years. We, at that time, picked a winner, and they won.

Now, we are trying to just balance that out with giving opportunities to biofuels, electric vehicles, wind, solar, and so on, all of which start and stop. It is not a consistent policy. It is not embedded in the tax code.

I want to ask Ms. Skor, when we look at, from a business standpoint, the importance of policy and regulatory certainty when you are making investment decisions, innovation decisions, and so on, how important is that?

Ms. SKOR. Thank you for the question, Senator. That is incredibly important. I think there is a very good example in terms of, my industry is producing right now cellulosic biofuel. That is up to 100 percent and beyond in terms of the GHG reductions. But we are not getting credit for it, because the technologies have been pending EPA review for over 5 years.

We as a Nation, we are leaving carbon reductions on the table. And then the impact is you have innovators sitting on the sidelines because they see a lack of certainty, a lack of a marketplace moving forward. Therefore they are going to sit this one out.

It really does stifle the innovation, the investment, that we need to continue to bring down the carbon intensity of corn ethanol, which we are doing a great job of doing that, and also to be able to get our industry to net zero and participating in the hard to electrify space. That is a place where we are going to be able to perform as a really important feedstock.

Senator STABENOW. Thank you. Just one more time, for the record, are biofuels responsible for high gas prices?

Ms. SKOR. No, quite the opposite. The more biofuels that we introduce into the fuel supply, the more we bring down the price at the pump for every driver.

Senator STABENOW. Thank you. It is also jobs, right, in rural America and certainly in rural Michigan.

One of the questions I have to ask as somebody who not only is a supporter of biofuels and rural jobs, but also electric vehicles being made in my great State, both are important to reducing carbon emissions in the transportation sector. I think it is important, just for the record, to say that is why the United Auto Workers, who make great automobiles and the new electric vehicles, strongly support the Renewable Fuel Standard as well. In fact, the UAW is the largest private union in Iowa with members employed by companies making farm equipment. They consistently talk about the fact that they are supportive.

Ms. Skor, does Growth Energy agree that both electric vehicles and biofuels are critical to reducing carbon emissions and petroleum use?

Ms. SKOR. Yes. Let me add that we appreciate that UAW submitted very strong remarks to EPA in support of a robust RFS. We have very ambitious climate goals, and there is no one size fits all solution. We are going to need every tool in the toolbox, which means biofuels alongside electrification.

The benefits of biofuels, those are going to be for the immediate, the mid, and the long term. In the immediate term, we have about 270 million cars on the road today. So biofuels allow us to have a solution for those cars, to bring down the emissions, to clean up the emissions and do so affordably and in an available way for all consumers.

In the mid to long term, if we are a strong industry today, that allows us to have the innovation that we are continuing to do to further drive down the carbon intensity of our low carbon fuel, but also participate into the hard to electrify space. For that, we need accurate carbon modeling, and we need to make sure that the incentives provide a fair, level playing field for all of the parties who want to be able to compete and participate.

Senator STABENOW. Thank you; I agree.

Mr. Chairman, I will yield back, and yield to my friend from Iowa, Senator Ernst.

Senator CARPER. Senator Ernst, your patience is rewarded. Thank you.

Senator ERNST. Yes, thank you so much. I appreciate that. Thank you, Mr. Chair.

I ask for unanimous consent to submit to the record comments from the Renewable Fuels Association and the Clean Fuels Alliance.

Senator CARPER. I think we are going to set a record here for unanimous consent requests. Without objection, so ordered.

[The referenced information follows:]

RFA
RENEWABLE FUELS ASSOCIATION

February 16, 2022

The Honorable Joni Ernst
United States Senate
730 Hart Senate Office Building
Washington, D.C. 20510

Dear Senator Ernst,

As the Senate Committee on Environment and Public Works (EPW) convenes a hearing today on "Renewable Fuel Standard—Challenges and Opportunities," I am respectfully submitting the attached written testimony from the Renewable Fuels Association (RFA) for consideration by the committee and requesting that it be included in the official record for the hearing.

As detailed in the attached testimony, we believe the RFS has been a resounding success and we applaud you and the entire EPW Committee for continuing your important oversight to ensure the RFS is being implemented and enforced as intended by Congress.

We are also attaching to the written testimony: 1) a detailed response to a fundamentally flawed study published Feb. 14, 2022 in the *Proceedings of the National Academy of the Sciences (PNAS)* that purports to examine the "environmental outcomes" of the RFS, and 2) a white paper presenting the facts about the RIN credits that are used to demonstrate compliance with the RFS.

On behalf of RFA's membership, we greatly appreciate your exemplary leadership and your unwavering support for America's farmers, the U.S. ethanol industry and the RFS. Thank you.

Sincerely,

Geoff Cooper

Geoff Cooper
President and CEO

TESTIMONY OF

THE RENEWABLE FUELS ASSOCIATION

U.S. SENATE, COMMITTEE ON ENVIRONMENT & PUBLIC WORKS

HEARING ON

"RENEWABLE FUELS STANDARD – CHALLENGES AND OPPORTUNITIES"

FEBRUARY 16, 2022

Chairman Carper, Ranking Member Capito, and Members of the Committee, the Renewable Fuels Association (RFA), is pleased to provide this written testimony for the record pertaining to today's hearing: Renewable Fuel Standard—Challenges and Opportunities.

RFA's mission is to drive expanded demand for American-made renewable fuels and bioproducts worldwide. Founded in 1981, RFA serves as the premier organization for ethanol industry leaders and supporters. With over 300 members, we work every day to help America become cleaner, safer, and more economically vibrant.

I. Summary of Testimony

The Renewable Fuels Standard, by any measure, has been a resounding success. In addition to decreasing reliance on imported petroleum, the RFS has reduced emissions of harmful tailpipe pollutants and greenhouse gases, lowered consumer fuel prices, supported hundreds of thousands of jobs in rural America, and boosted the agricultural economy by adding value to the crops produced by our nation's farmers. And far from "distorting the free market" as RFS opponents often claim, the policy has been remarkably effective in stimulating market competition and giving consumers more choices. Simply put, the RFS ensures renewable fuels are able to gain access to a fuel market that had been monopolized for nearly a century and would otherwise be closed to competition.

To expound upon the success of the RFS over the last 17 years, to respond to unfounded criticisms of the program, and to discuss opportunities moving forward, the testimony that follows will provide details on the following subjects:

- the undeniable environmental benefits of the RFS since its expansion and extension in 2007, including reducing greenhouse gas emissions by approximately one billion metric tons;

- RIN (renewable identification number) credits under the RFS do not increase the price of liquid fuel at the retail level and their cost is fully recoverable by the obligated party;
- issuance of Small Refinery Exemptions (SREs) has had a negative impact on U.S. biofuel producers, farmers and the environment;
- removal of unnecessary regulatory barriers that block the use of fuel blends containing higher levels of ethanol, such as 15 percent ethanol (E15) blends would enhance and improve RFS compliance and effectiveness; and
- the opportunity for the RFS to help meet net-zero carbon emission goals by 2050 can be complemented by a nationwide technology-neutral, performance-based low carbon fuel standard.

It is important to note that in addition to its environmental benefits, ethanol also makes a vital contribution to our nation's economy. The 206 ethanol biorefineries across the country serve as crucial drivers of employment in the communities in which they operate. Even as the COVID-19 pandemic continued to disrupt the U.S. economy and world energy markets in 2021, the production of 15 billion gallons of ethanol directly employed 73,000 American workers in the manufacturing and agriculture sectors. In addition, the ethanol industry supported 330,000 indirect and induced jobs across all sectors of the economy. Meanwhile, the industry generated $29 billion in household income and contributed $52 billion to the national Gross Domestic Product (GDP) in 2021.[1] These significant employment impacts and economic contributions should be taken into consideration by Congress as it examines potential future energy and climate policies that may impact the biofuels sector.

II. The RFS is responsible for substantial greenhouse gas (GHG) emissions reductions, and today's corn ethanol cuts GHG emissions by half compared to conventional gasoline.

Beyond creating new market opportunities for farmers, reducing our dependence on imported oil, and lowering the cost of fuel to the consumer, the RFS has also served as the only federal legislation requiring greenhouse gas (GHG) emissions reductions from the motor fuels sector.

A recent analysis conducted by Stefan Unnasch and Debasish Parida of Life Cycle Associates indicated that the GHG emissions reductions achieved under the Renewable Fuel Standard far exceed the reductions originally projected by EPA.[2] Specifically, between 2008 and 2020, the

[1] J.M. Urbanchuk (ABF Economics). "Contribution of the Ethanol Industry to the Economy of the United States in 2021." Forthcoming (February 2022).
[2] S. Unnasch and D. Parida. "GHG Reductions from the RFS2 – A 2020 Update." Life Cycle Associates Report LCA.6145.213.2021. February 11, 2021. Prepared for Renewable Fuels Association.
https://ethanolrfa.org/file/748/LCA_-_RFS2-GHG-Update_2020.pdf

use of biofuels under the RFS resulted in cumulative savings of 980 million metric tons of carbon dioxide-equivalent greenhouse gas emissions.

Further, according to the report, the carbon intensity of corn-based ethanol used under the RFS is 45% below the carbon intensity of gasoline, and corn ethanol's lifecycle carbon emissions have dropped 20% between 2008 and 2020. The authors attribute ethanol's shrinking carbon footprint primarily to improvements in the corn ethanol production process, growth in the use of low-carbon biogas as the process fuel, and the elimination of coal as a thermal energy source for dry mill ethanol plants.

The Life Cycle Associates study is consistent with recently released research from Environmental Health & Engineering Inc., which showed that GHG emissions for ethanol are 32% to 62% lower than gasoline, with a central best estimate of 46%, including emissions from hypothetical land use changes.[3] In addition, a recent study by the Department of Energy's Argonne National Laboratory, found typical corn ethanol provides a 44-52 percent GHG savings compared to gasoline.[4]

III. RINs under the RFS do not increase the price of liquid fuel at the retail level and their cost is fully recoverable by the obligated party.

A RIN, or Renewable Identification Number, is a 38-digit alphanumeric code assigned to a gallon of renewable fuel produced in, or imported into, the U.S. for the purpose of tracking compliance with the RFS. In the case of ethanol, the RIN remains "attached" to the renewable fuel until it is blended with gasoline. Blenders and refiners who purchase ethanol receive the associated RIN credit *free of charge*.

When the ethanol is blended with gasoline, the RIN is separated and becomes a tradeable compliance credit. Each year, obligated parties under the RFS (i.e., refiners and importers) turn RINs in to EPA to demonstrate compliance with their renewable volume obligations (RVOs).

If an obligated party blends *more* than its required volume of renewable fuel, it will have surplus RINs that may be sold to other parties or banked for compliance with a portion of the following year's RVO requirement. Conversely, if an obligated party blends *less* than its required volume, it may purchase RINs from other parties to offset the shortfall, or it may carry a deficit forward to the next year.

While some merchant refiners argue they are "required" to purchase RINs from other refiners or blenders, the truth is they could have invested in renewable fuel blending infrastructure. This

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[3] Environmental Health & Engineering Report https://eheinc.com/who-we-are/news/article/corn-ethanol-emits-46-less-greenhouse-gases-than-gasoline/

[4] Lee, U., Kwon, H., Wu, M. and Wang, M. (2021), Retrospective analysis of the U.S. corn ethanol industry for 2005–2019: implications for greenhouse gas emission reductions. *Biofuels, Bioprod. Bioref.*, 15: 1318-1331. https://doi.org/10.1002/bbb.2225

would have allowed them to blend physical volumes of renewable fuel and capture RINs free of charge.

Following passage of the expanded RFS in 2007, many refiners took steps to increase their renewable fuel blending capacity so they could capture RINs internally. Meanwhile, other refiners chose not to invest in blending capacity, choosing instead to buy RINs from parties who blended more than required.

It is also well understood that refiners who buy RIN credits rather than blending ethanol recoup their RIN costs because the market price of gasoline blendstock and other refined products includes the RIN value. Thus, RINs are not a "sunk cost" and do not negatively affect the financial performance of refining companies, both large and small.

- Oil industry firm Turner, Mason & Company agrees that RINs don't affect refining margins, stating, "RFS compliance costs are substantially passed from refiners" to wholesale gasoline buyers.[5]

- The Environmental Protection Agency found that RINs are not negatively affecting profit margins for oil refiners. According to EPA, "…obligated parties, including small entities, are generally recovering the cost of acquiring the credits necessary for compliance with the RFS standards through higher sales prices of the petroleum products they sell."[6]

- EPA also concluded that "…refiners are generally able to recover the cost of RINs in the prices they receive for their refined products, and therefore high RIN prices do not cause significant harm to refiners."[7]

- The EPA analyzed this issue in detail again in its December 2021 proposal to deny petitions for SREs, finding, "Obligated parties that choose to purchase the RINs they need for compliance on a ratable basis (i.e., purchase on a systematic, regular basis the number of RINs needed to satisfy their obligation for all the fuel sold each day) will recover the cost of the RINs they purchase in the sales price of the petroleum fuel they sell."[8]

- Economists from Iowa State University found "…added refiner costs from complying with the RFS are passed on to blenders through higher gasoline prices. We show that high RIN

[5] Turner, Mason, and Company. "Pass it on Down." Blog post available by subscription. https://www.turnermason.com/blog/
[6] U.S. Environmental Protection Agency. (December 2017) Renewable Fuel Standard Program – Standards for 2018 and Biomass-Based Diesel Volume for 2019: Response to Comments. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100TDDH.pdf
[7] *Id.*
[8] U.S. Environmental Protection Agency. (2021). Proposed RFS Small Refinery Exemption Decision. https://www.epa.gov/renewable-fuel-standard-program/proposal-deny-petitions-small-refinery-exemptions

prices…have no impact on profits of refiners, blenders, or integrated oil companies."[9]

- Refiner Andeavor, which merged with Marathon in 2018, stated, "RIN costs are passed through at the bulk finished product sales points and provide refiners with coverage of their exposure to them."[10]

- Even the American Petroleum Institute agrees: "RIN costs are largely recovered by refineries, large and small, through the increased value of gasoline and diesel fuel they supply to the market."[11]

As noted above, RIN costs are passed through from refiners to wholesale purchasers, leading to slightly higher wholesale prices for gasoline blendstock. However, RINs have the opposite effect on renewable fuels, lowering the cost of ethanol for blenders. When ethanol is blended with gasoline to create a finished fuel, the RIN-enabled discount on ethanol fully offsets the RIN cost passed through on gasoline by refiners. For fuel blends that contain more than 10% ethanol (such as E15 or E85), the RIN enables a sufficiently larger discount that is typically shared with consumers in the form of lower retail prices.

There is no evidence to support the notion that RINs push retail gas prices higher. In fact, RINs and retail E10 gas prices tend to be negatively correlated (coefficient = -0.3 since January 2013), with periods of high gas prices often occurring during periods of *low* RIN prices and vice versa. According to a study by Iowa State University "…the net effect on the [retail] price of E10 of high RIN prices is zero: higher gasoline prices are offset by lower ethanol blending costs and the price of E10 remains constant."[12]

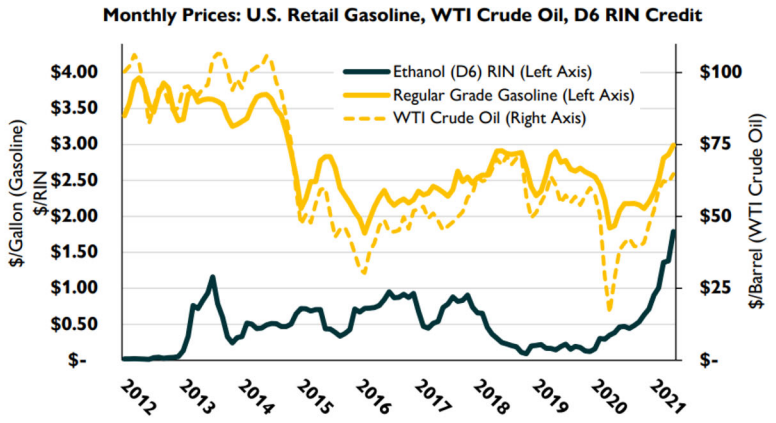
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[9] B.A. Babcock, G.E. Lade, and S. Pouliot, Iowa State University Center for Agricultural and Rural Development, Impact on Merchant Refiners and Blenders from Changing the RFS Point of Obligation, CARD Policy Brief 16-PB 20, at 1 (Dec. 2016). https://www.card.iastate.edu/products/publications/pdf/16pb20.pdf

[10] EPA Document Center. EPA-HQ-OAR-2016-0544-0244. Also available at: http://www.ascension-publishing.com/RFS-Tesoro.pdf

[11] American Petroleum Institute http://www.americanpetroleuminstitute.com/~/media/Files/News/Letters-Comments/2017/API-Letter-2-12-18.pdf

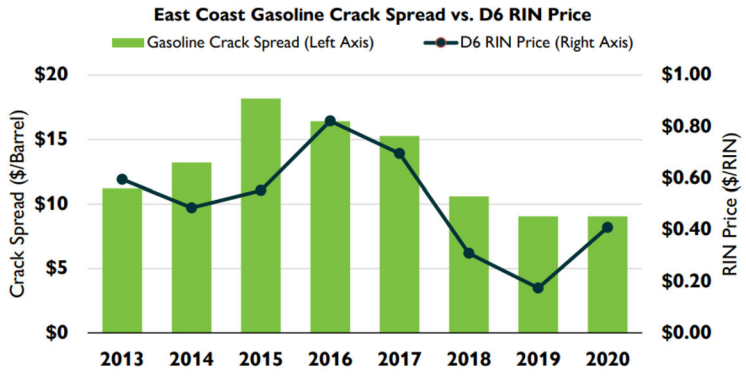
[12] *See Supra* note 9



Source: OPIS and Energy Information Administration

The primary driver of retail gasoline prices has always been crude oil prices—that has not changed with the introduction of RINs during the RFS era. Between January 2013 and January 2021, retail gasoline prices were almost perfectly correlated with WTI crude oil prices (coefficient of 0.96).

Contrary to the rhetoric coming from some in the refining industry, there is no statistical evidence to support the argument that higher RIN prices negatively affect refiner margins or earnings. In fact, the gasoline "crack spread" (a surrogate for refining margins) for East Coast refineries shows a modest positive correlation with RIN prices in recent years, meaning *refining margins are highest when RIN prices are highest* (this supports the argument that RINs are embedded in the refinery crack spread).



Source: RFA analysis of EIA and OPIS data

Analysts from Wells Fargo Securities released an analysis in 2017 that examined the potential impacts of RFS compliance costs on merchant refiners, finding, "Most independent refiners nowenjoy a net *benefit* from RINs, based on our analysis." The analysts also found that "RINs costs are being passed along" and "investors should not spend much time and effort" worrying about RINs.[13]

In quarterly earnings statements, refiners across the country have admitted that weaker refining margins in 2020 were due to COVID-19 and the dramatic collapse in fuel demand resulting from travel restrictions—not the RFS.

IV. Small Refinery Exemptions issued by the EPA have had a negative impact on renewable fuel producers, US farmers and America's environment.

During the previous administration, the U.S. EPA issued 85 waivers to oil refiners allowing them to ignore their legal obligations under the RFS. In essence, oil companies used these exemptions to avoid blending renewable fuels (e.g., ethanol and biodiesel) with the petroleum-based fuels produced at their refineries.

The 85 waivers issued by the Trump administration marked a nearly four-fold increase over the 23 exemptions issued by the previous administration. In addition, the Trump administration's exemptions reduced the 2016-2018 RFS blending requirements by a

[13] DTN Coverage: https://www.dtnpf.com/agriculture/web/ag/blogs/ethanol-blog/blog-post/2017/11/27/wells-fargo-independent-refiners-rin

cumulative total of 4.04 billion gallons of renewable fuel, a six-fold increase over the cumulative total of 690 million gallons waived by the Obama administration for 2013-2015.

The dramatic increase in refinery exemptions under the Trump administration was a source of significant controversy, leading to numerous legal challenges. In one landmark case, *Renewable Fuels Association et al. v. EPA*[14], the U.S. Court of Appeals for the Tenth Circuit in January 2020 overturned certain exemptions that had been illegally granted by EPA and found the agency had grossly exceeded its authority in granting the waivers. In December 2021, EPA finally proposed to adopt the Tenth Circuit decision nationwide and reject 65 pending small refinery exemption petitions.

It is an indisputable fact that renewable fuel producers and the farmers who supply corn, sorghum, soybeans, canola, and other crops to the biofuel supply chain have experienced significant financial damages due to the loss of demand stemming from the refinery exemptions. As recognized by then President-Elect Biden, "Those waivers severely cut ethanol production, costing farmers income and ethanol plant workers their jobs."[15]

But in addition to the economic harm, the refinery exemptions have caused substantial environmental damages as well. When refiners are inappropriately released from their renewable fuel blending obligations, they supply more petroleum-based fuels—like gasoline and diesel—to the market in lieu of renewable fuels. The lifecycle greenhouse gas emissions associated with producing and using those petroleum fuels are much larger than the GHG emissions associated with the renewable fuels that would have been used in the absence of the refinery waivers. In other words, the exemptions lead to higher GHG emissions from the transportation sector than would have been the case if the exemptions had not been issued and the required volumes of renewable fuel had been used.

RFA estimated the additional GHG emissions that resulted from EPA's issuance of waivers allowing small refiners to escape their 2016-2018 RFS obligations:

- The 85 exemptions granted for 2016-2018 reduced refiners' renewable fuel blending obligations by more than 3.8 billion "wet" gallons of renewable fuel. The likely mix of avoided renewable blending was 3.16 billion gallons of grain-based ethanol; 608 million gallons of biodiesel, renewable diesel, sugarcane ethanol, and other advanced biofuels; 48 million ethanol-equivalent gallons of biogas; and 2.5 million gallons of cellulosic ethanol.

[14] *Renewable Fuels Association et al. v. EPA* ; 519 F. Supp. 3d 1 (D.D.C. 2021)
[15] DTN Coverage: https://www.dtnpf.com/agriculture/web/ag/blogs/ethanol-blog/blog-post/2020/11/30/cooper-suggests-rfs-volumes-rule

- In place of the forgone renewable fuel blending for 2016-2018, roughly 2.76 billion gallons of gasoline and diesel were used instead.

- The use of gasoline and diesel in lieu of the 2016-2018 waived renewable fuel volumes led to an increase in GHG emissions from the transportation sector of 12.6 million metric tons of CO2-equivalent GHG.

V. Removal of unnecessary regulatory barriers blocking the use of fuel blends that contain higher levels of ethanol, such as 15 percent ethanol blends (E15), would enhance and improve RFS compliance, lower gas prices for consumers and reduce tailpipe emissions.

Sales of E15, a blend of 15% ethanol and 85% gasoline, expanded substantially after the U.S. EPA finalized regulatory changes in May 2019 allowing the fuel to be sold year-round. Prior to the rule change by EPA, many fuel retailers found it difficult or impossible to offer E15 during the summer months in conventional gasoline markets, due to outdated and inequitable gasoline volatility regulations.

Although national statistics on E15 sales volumes are not available, government agencies in Minnesota and Iowa publish state-level statistics. It is notable that E15 sales in the two states grew by one-third in 2019 (the first year that unimpeded summertime E15 sales were allowed) compared to 2018. Minnesota E15 volumes in 2019 and 2020 did not experience the "summertime plunge" that plagued sales in prior years. And, notably, E15 sales in Iowa rose 24% in 2020 (versus 2019 levels) despite the pandemic's effect on overall gasoline demand.[16] However, on July 2, 2021, the D.C. Circuit Court of Appeals ruled that EPA's 2019 regulation allowing year-round sales of E15 should be vacated, finding that the EPA exceeded its authority by extending the existing E10 volatility waiver to E15.[17]

The RFA supports the pursuit of all options to restore the retailer sector's ability to offer year-round sales of E15. Our organization supports S. 2339, the *Consumer and Fuel Retailer Choice Act*, introduced by Sens. Deb Fischer (R-NE) and Amy Klobuchar (D-MN) and co-sponsored by EPW members Sens. Joni Ernst (R-IA) and Tammy Duckworth (D-IL). The legislation would resolve the E15 RVP barrier issue and restore the ability for retailers to offer the fuel on a year-round basis. However, RFA does not support a legislative resolution to the E15 barrier if it is tied to legislative reforms that would weaken or undermine the RFS (e.g., lowering RFS requirements, changing the RFS point of obligation, capping RIN prices, etc.).

[16] RFA Analysis of Minnesota Department of Commerce Data https://ethanolrfa.org/2021/04/even-amidst-pandemic-iowa-e15-sales-surge-to-new-record-in-2020/
[17] *See Supra* Note 11

RFA is also pursuing other options to resolve the E15 RVP issue, including requesting that EPA take action to reduce the RVP cap of summer conventional gasoline. On December 9, 2021, RFA and several biofuels and agricultural organizations sent a letter to EPA supporting an RVP regulatory remedy that would lower the RVP cap by 1 psi, putting E10, E15, and any higher ethanol blends on equal regulatory footing.[18]

Further, there are emissions benefits to be gained by removing the 1-psi waiver. A new study conducted for RFA by Janet Yanowitz, P.E., Ph.D. using EPA's MOVES3.0.2 tool concluded that reducing the RVP of conventional gasoline blendstock by 1 psi "…would be beneficial to air quality, as emissions of carbon monoxide (CO), oxides of nitrogen (NOx) and volatile organic compounds (VOCs) would be reduced."[19] The study concluded that "if the elimination of the 1-psi waiver [for E10] leads to the replacement of E10 with E15, it will also decrease greenhouse gases and particulate emissions."

RFA also supports the bipartisan effort of seven Midwest Governors to pursue state-level actions that could level the regulatory playing field for E10 and E15 and allow retailers in their states to sell E15 unimpeded during the summer.[20]

VI. The RFS is the foundation to meeting net-zero carbon emissions goals and can be complemented by a nationwide technology-neutral, performance-based clean fuel standard.

A national strategy to achieve net-zero GHG emissions by 2050 cannot rely exclusively on electric vehicles to decarbonize the transportation sector. Complementary low- and zero-carbon solutions in the internal combustion engine (ICE) vehicle market will also be required to secure carbon neutrality by mid-century.

Implementation of strong Renewable Fuel Standard (RFS) volume requirements in 2023 and beyond will ensure low-carbon biofuels have access to a growing market. This year is the final year for statutorily prescribed RFS volume requirements, and EPA is expected to propose RFS requirements for 2023 and beyond this summer. In order to maximize the GHG emissions benefits of the RFS program, we believe EPA must implement future RFS volume requirements that continue to grow beyond the levels proposed for 2022.

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[18] RFA Letter to EPA https://ethanolrfa.org/media-and-news/category/news-releases/article/2021/12/farm-biofuel-groups-ask-epa-to-resolve-summertime-e15-barrier

[19] Janet Yanowitz, P.E., Ph.D., Ecoengineering, Inc., Emissions Impacts of the Elimination of the 1-PSI RVP Waiver for E-10 https://ethanolrfa.org/file/2101/Emissions%20Impacts%20of%20Eliminating%20the%201-psi%20RVP%20Waiver%20for%20E10%20%20Nov%202021.pdf

[20] Letter for Govs. Reynolds (R-IA), Ricketts (R-NE), Walz (D-MN), Burgrum (R-ND), Noem (R-SD), Parson (R-MO), and Evers (D-WI) to EPA Administrator Regan. Nov. 3, 2021. https://files.constantcontact.com/a8800d13601/eb36be2b-82b7-4a0b-aa5f-ce901e722c0d.pdf

In addition, we believe future decarbonization policies can complement the RFS. Future policies should take a technology-neutral, performance-based approach that focuses on reducing carbon emissions and increasing fuel efficiency without dictating the use of specific fuels or vehicles. That's why we support exploring the concept of a national Clean Fuel Standard (also called a Low Carbon Fuel Standard), and we are hopeful Congress begins serious discussions around such a policy in 2022.

Through renewable fuels like ethanol, the U.S. farm sector presents an effective and immediate opportunity for decarbonizing liquid fuels across all segments of the transportation sector. As stated previously, today's corn ethanol already reduces GHG emissions by roughly half, on average, compared to gasoline (i.e., similar to the GHG reduction offered by BEVs, according to the International Energy Agency).

With the rapid emergence of new technologies and more efficient practices, even greater GHG reductions are coming to the corn ethanol sector. In fact, analysis by USDA found that some biorefineries could produce corn ethanol that offers a 70 percent GHG reduction versus gasoline as soon as this year.[21]

Indeed, the U.S. ethanol industry is well on its way to producing corn ethanol that is fully carbon neutral. With the adoption of carbon capture utilization and storage (CCUS); biogas substitution; and climate-smart farming practices, corn ethanol is expected to achieve net zero emissions, on average, by 2050 or sooner. In fact, RFA's member companies are so confident about the promise of carbon neutral ethanol that they adopted a resolution last summer to achieve a net-zero carbon footprint, on average, for ethanol by 2050 or sooner. This pledge was memorialized in a letter to President Biden last July.

Clearly, the U.S. agriculture sector—through increased production and use of ethanol and other biofuels—has the ability to jumpstart decarbonization efforts now. America's farmers and biofuel producers offer an effective and economical solution for drastically reducing the carbon impacts of liquid fuels across all segments of the transportation sector, including light-, medium-, and heavy-duty vehicles; the marine sector; and even the aviation sector, through the utilization of ethanol as a feedstock in the production of sustainable aviation fuels (SAF).

To ensure a wide variety of low- and zero-carbon technologies are allowed to contribute to national decarbonization efforts, fair, accurate, and consistent methodologies are needed for assessing the lifecycle carbon footprint of different fuels and vehicles.

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[21] Jan Lewandrowski, Jeffrey Rosenfeld, Diana Pape, Tommy Hendrickson, Kirsten Jaglo & Katrin Moffroid (2020) The greenhouse gas benefits of corn ethanol – assessing recent evidence, Biofuels, 11:3, 361-375, DOI: 10.1080/17597269.2018.1546488 https://www.tandfonline.com/doi/full/10.1080/17597269.2018.1546488

As Congress considers future climate and energy policies, RFA strongly recommends that each potential fuel and vehicle combination should be evaluated based on the GHG emissions associated with its full "cradle-to-grave" supply chain. The Department of Energy's Argonne National Laboratory GREET model is recognized worldwide as the "gold standard" for conducting this type of analysis, and RFA strongly supports its use for policy and regulatory decision-making.

VII. Conclusion

On behalf of the membership of the Renewable Fuels Association, we thank the Senate Committee on Environment and Public Works for this important hearing regarding the Renewable Fuel Standard.

To reiterate, RFA believes that the RFS has been one of the most successful public policies to be enacted, resulting in environmental benefits and accomplishing the goals of the program set out by the enacting legislation. Since its inception, the RFS has reduced greenhouse gas emissions by approximately one billion metric tons. RFA strongly believes that RINs prices do not increase the price of liquid fuel at the retail level and their cost is recoverable by the obligated party. Further, we believe the issuance of SREs has had a negative impact on US biofuel producers, farms and America's environment. We also support the removal of unnecessary regulatory barriers that are blocking the use of fuel blends that contain higher levels of ethanol, such as E15 would enhance and improve RFS compliance and effectiveness. Lastly, RFA believes the RFS could serve as the foundation to meet a net zero carbon emissions goals by 2050 and should be complemented by a nationwide technology-neutral, performance-based Clean Fuel Standard (or LCFS).

RENEWABLE FUELS ASSOCIATION

February 14, 2022

Preliminary Rebuttal to PNAS Report: "Environmental outcomes of the U.S. Renewable Fuel Standard" (Lark *et al.*)

A new report published today in the *Proceedings of the National Academy of the Sciences*, funded by the National Wildlife Federation, purports to examine the "environmental outcomes" of the Renewable Fuel Standard. In keeping with their previous "research" on biofuels and the RFS, the authors of this new paper precariously string together a series of worst-case assumptions, cherry-picked data, and disparate results from previously debunked studies to create a completely fictional and erroneous account of the environmental impacts of the Renewable Fuel Standard.

Below are a number of key facts that were purposely omitted from the new report by Lark *et al.*

FACT: Recent studies show that corn ethanol reduces GHG emissions by 40-50 percent compared to gasoline, even when emissions from hypothetical land use changes are included.

Today's corn ethanol already reduces GHG emissions by roughly half, on average, compared to gasoline. According to the Department of Energy's Argonne National Laboratory, typical corn ethanol provides a 44 percent GHG savings compared to gasoline, including land use change emissions.[1] Similarly, researchers affiliated with Harvard University, MIT, and Tufts University concluded that today's corn ethanol offers an average GHG reduction of 46 percent versus gasoline.[2] In addition, the California Air Resources Board (CARB) found that ethanol used in the state in 2020 reduced emissions by 41 percent, on average, compared to gasoline. From 2011 to 2020, CARB data show that the use of ethanol cut GHG emissions from the California transportation sector by 27 million MT CO2e, more than any other fuel used to meet the state's Low Carbon Fuel Standard requirements.[3]

FACT: The law establishing the RFS2 prohibits the use of crops from newly expanded cropland.

[1] Lee, U., Kwon, H., Wu, M. and Wang, M. (2021), Retrospective analysis of the U.S. corn ethanol industry for 2005–2019: implications for greenhouse gas emission reductions. *Biofuels, Bioprod. Bioref.*, 15: 1318-1331. https://doi.org/10.1002/bbb.2225

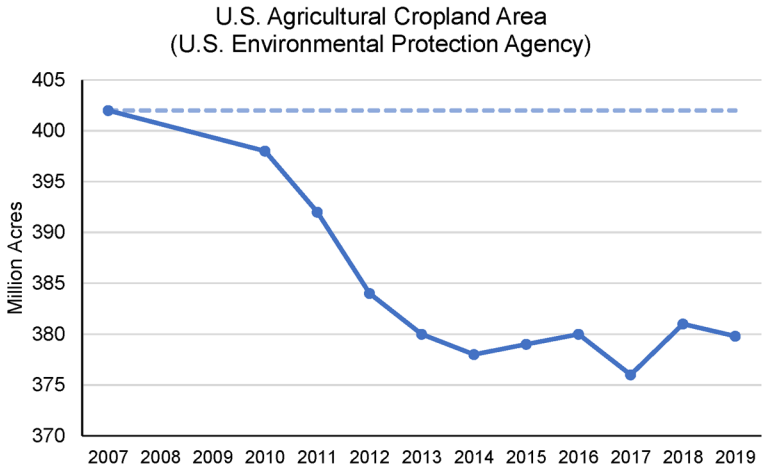
[2] Melissa J Scully *et al* (2021), Carbon intensity of corn ethanol in the United States: state of the science. *Environ. Res. Lett.* **16** 043001. https://iopscience.iop.org/article/10.1088/1748-9326/abde08

[3] CARB. "Low Carbon Fuel Standard Reporting Tool Quarterly Summaries." Viewed Nov. 20, 2021. https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

As acknowledged by Lark *et al*., "the RFS legislation contains several environmental safeguards to try to prevent perverse outcomes…" One of those environmental protections requires that biofuel producers may only use crops from agricultural land that had been cleared or cultivated prior to 2007. Thus, any crops produced on newly expanded cropland (i.e., after 2007) would not be eligible for biofuel production under the RFS.

FACT: According to EPA, U.S. cropland has decreased—not expanded—since the RFS2 was adopted in 2007.

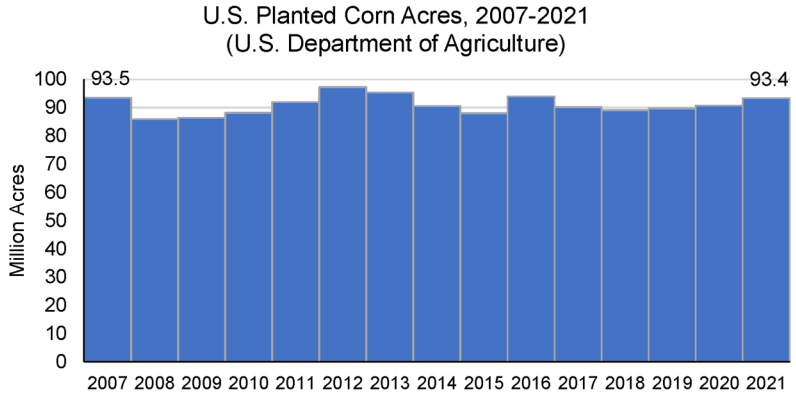
To ensure compliance with the statutory limitation on cropland, EPA conducts an annual assessment of the amount of U.S. agricultural cropland. EPA's annual assessment shows that U.S. cropland has *receded* since the RFS2 was adopted in 2007, directly refuting the claim from Lark *et al.* that the RFS has somehow caused cropland to expand since 2007. According to EPA, the total amount of U.S. cropland in recent years has been 20-25 million acres *lower* (5-6 percent) than the amount of cropland in 2007 when the RFS2 was adopted (2020 and 2021 data have not yet been published by EPA).



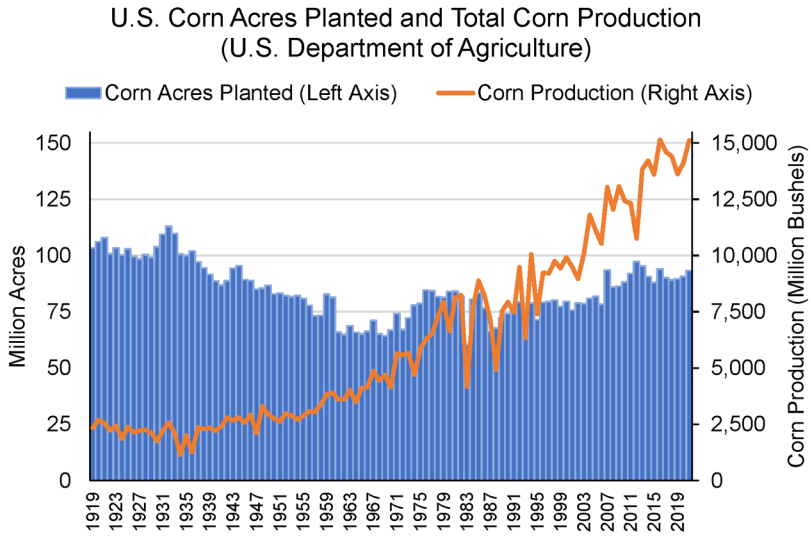
FACT: Corn acreage has been relatively flat since the RFS2 was adopted in 2007.

Looking specifically at corn acres, data from USDA show that the amount of land planted to corn in 2021 was essentially identical to the amount of land planted to corn in

the spring of 2007 before the RFS2 was adopted. In fact, corn acres planted have been relatively consistent since 2007, averaging 91 million acres per year.



In addition, USDA data show that the amount of land dedicated to corn production today is well below historical levels and far below (18 percent) the peak level of 113 million corn acres in 1932.



FACT: The additional corn supply needed to meet increased ethanol demand has come primarily from yield increases and secondarily from crop switching—not from acreage expansion.

As ethanol production has grown under the RFS program, the additional corn needed has come primarily from increased efficiency on existing cropland—not from expanding acreage.

For example, U.S. farmers planted 86 million acres of corn in 2008 (the first year of the Lark *et al.* study period) and harvested 78.6 million acres to produce a crop of 12.04 billion bushels. Thus, the average yield that year was 153.3 bushels per acre. In 2018 (the record-high year for ethanol production), farmers planted 89.1 million acres and harvested 81.3 million acres to produce a crop of 14.42 billion bushels. The average yield in 2018 was 176.4 bushels per acre.

Thus, farmers produced 2.38 billion bushels more (20 percent) in 2018 than in 2008, but used only 2.7 million more harvested acres (3 percent) to do it. Importantly, the slight increase in corn acres came from reductions in planted acres for other crops (like wheat and cotton), not from expanding cropland. Yield growth alone accounted for about 80 percent of the corn production increase between 2008 and 2018. Meanwhile, corn use for ethanol was 2.32 billion bushels higher in 2018 than in 2008, meaning the increase in corn production slightly outpaced the increase in corn use for ethanol.

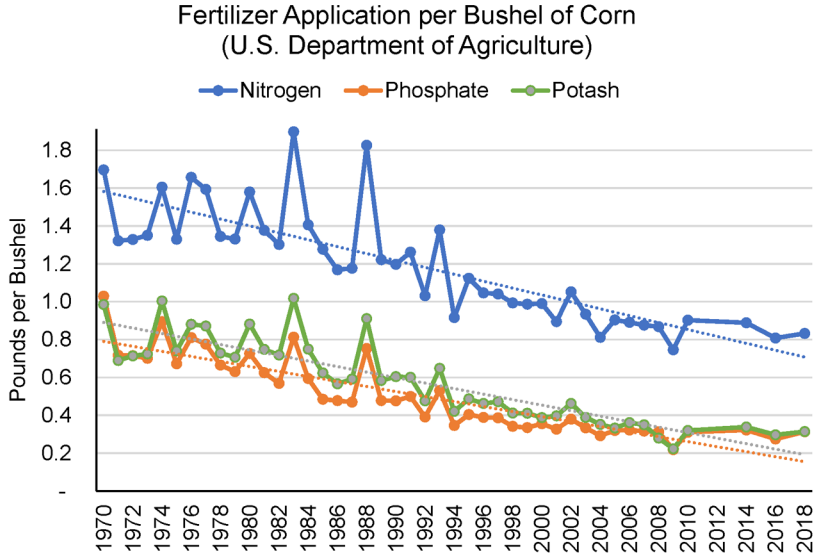
	2008	2018	Change	% Change
Total Agricultural Cropland (m. acres)[1]	402.0	381.0	-21.0	-5.1%
Corn Acres Planted (m. acres)[2]	86.0	89.1	3.1	3.6%
Corn Acres Harvested (m. acres)	78.6	81.3	2.7	3.4%
Yield per Acre (bu. per acre)	153.3	176.4	23.1	15.1%
Corn Production (m. bu.)	12,043	14,420	**2,377**	19.7%
Ethanol Production (m. gal.)[3]	9,309	16,091	6,782	72.9%
Corn Use for Ethanol & Co-products (m. bu.)[4]	3,325	5,646	**2,321**	69.8%

1. EPA
2. USDA
3. EIA
4. RFA based on average ethanol yield per bushel

FACT: The amount of fertilizer required to produce a bushel of corn has fallen dramatically in recent decades.

The Lark et al. paper suggests that the RFS is somehow responsible for "increasing annual nationwide fertilizer use by 3 to 8%." However, data from USDA show that total fertilizer (nitrogen, phosphate, and potash) application on corn in recent years is slightly less than the total amount of fertilizer typically applied to corn in the 1970s and 1980s. However, because today's corn output is so much larger than in the 1970s and 1980s,

the amount of fertilizer required to produce a bushel of corn has dropped precipitously. USDA data show that nitrogen fertilizer use per bushel is down more than 50 percent since 1970, while phosphate and potash use are each down nearly 70 percent. Clearly, fertilizer use for corn production has not increased since the RFS2 was adopted in 2007.



FACT: The methodology used by *Lark et al.* to estimate land use changes is highly flawed and has been rejected after rigorous critique by the scientific community.

Despite the fact that EPA and USDA data show no overall cropland expansion since the RFS2 was adopted, Lark et al. claim that "native" grassland with high carbon storage has been converted to corn production because of the RFS. This claim is based on previous studies conducted by Lark and others that rely on comparisons of satellite imagery from different time periods.

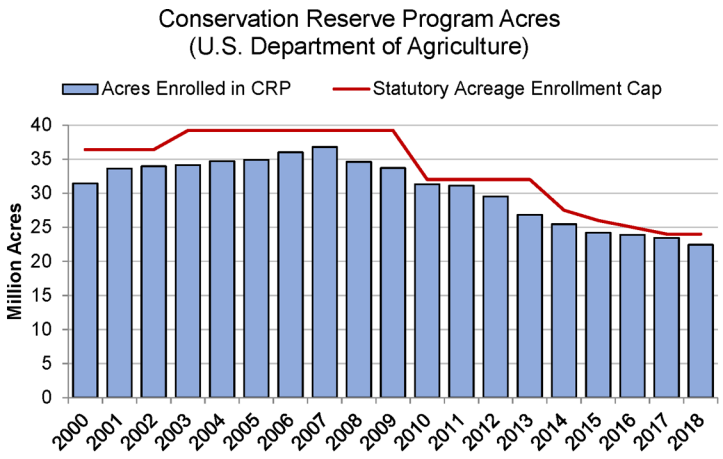
If, for example, a satellite image from 2008 shows a particular parcel of land is covered in grass, but a satellite image from 2016 shows that same parcel is planted to corn, the authors would treat this as a conversion of "native" grassland to corn. Using an opaque

methodology, they then assign that "new" corn production to ethanol and allocate the assumed emissions from the land conversion to the ethanol. There are multiple problems with this approach.

First, the satellite tools used by Lark and others have great difficulty distinguishing between different land cover types. For example, one tool relied heavily upon by Lark et al. (USDA's "Cropland Data Layer," or CDL) often cannot tell the different between wheat, alfalfa hay, grass, and other land cover types. And even if the tools could identify land covered in grass with a high degree of certainty, they cannot distinguish between grass pastureland, grass hay, land enrolled in the Conservation Reserve Program, and "native" grassland. Of course, these land cover types would have much different carbon storage profiles. Yet, Lark et al. treat all of these land cover types (sometimes also including wheat, alfalfa and other crops) as "native" grassland. USDA, which maintains several of the tools used by Lark et al., has warned that, "Unfortunately, the grassland-related categories have traditionally *had very low classification accuracy* in the CDL."

Second, the authors attempt to characterize these supposed land cover changes as "empirical" and "observed," suggesting that they actually verified these supposed conversions with their own eyes. This is not the case. Rather, they are relying on highly uncertain and error-prone satellite images for their purported "empirical observations" of land use changes.

In addition, any transitions of non-cropland into cropland since the RFS2 was adopted are most likely explained by expired CRP land returning to cropland, not conversion of "native" grassland. Yet, from a carbon emissions standpoint, the Lark et al. methodology treats a transition of CRP ground back to cropland the same as a conversion of native grassland to cropland. In any case, it is incorrect to argue that the return of some former CRP land to crop production is solely due to the RFS. Rather, Congress has repeatedly lowered the cap on the amount of land eligible for enrollment in CRP, dropping the limit from 39 million acres in 2008 (the first year of the Lark et al. study period) to just 25 million acres in 2016 (the final year of the study period). Thus, it should be no surprise that some of the land no longer eligible for CRP enrollment returned to crop production.



The obvious flaws in the methodology used by Lark *et al.* and several of the underlying studies have been examined and critiqued in detail by, among others, the following:

- Remote sensing experts at Southern Illinois University
  - https://ethanolrfa.org/file/1833/SIUE-Rebuttal-on-USDA-CDL-Use.pdf
  - https://ethanolrfa.org/file/1834/SIUE-Review-of-Land-Use-Change-Literature-07-2019.pdf

- Energy economists and lifecycle assessment experts from Northwestern University, the Dept. of Energy's Argonne National Laboratory, DOE's Oak Ridge National Laboratory University of Illinois-Champaign/Urbana, and University of Illinois-Chicago
  - https://ethanolrfa.org/file/2005/jjgi-10-00281.pdf
  - https://ethanolrfa.org/file/807/Measured-extent-of-agricultural-expansion-depends-on-analysis-technique_Dunn-et-al_2016.pdf
  - https://ethanolrfa.org/file/1447/1373e8a3f091431ad5_g0m6ibjcr.pdf
  - https://ethanolrfa.org/file/2001/LUC-Ethanol-Plant-Proximity-Crop-Prices_Li-et-al_2018-12.pdf

- Economists at the Renewable Fuels Association
  - https://ethanolrfa.org/file/1932/USDA-Data-Show-Cropland-Reductions-in-Counties-with-Ethanol-Plants-from-1997-2012.pdf
  - https://ethanolrfa.org/media-and-news/category/news-releases/article/2015/04/university-of-wisconsin-study-based-on-shaky-foundation-of-faulty-data-and-conclusions
  - https://ethanolrfa.org/file/1814/Wisconsinethanolresponse11.15.pdf

Renewable Fuels Association March 2021

THE TRUTH ABOUT RINS

What are RINs?

A RIN (or Renewable Identification Number) is a 38-digit alphanumeric code assigned to a gallon of renewable fuel produced in, or imported into, the U.S. for the purpose of tracking compliance with the Renewable Fuel Standard (RFS). In the case of ethanol, the RIN remains "attached" to the renewable fuel until it is blended with gasoline. Blenders and refiners who purchase ethanol receive the associated RIN **free of charge**.

When the ethanol is blended with gasoline, the RIN is separated and becomes a tradeable compliance credit. Each year, obligated parties under the RFS (typically refiners/importers) turn RINs in to EPA to demonstrate compliance with their renewable volume obligations (RVOs).

If an obligated party blends *more* than its required volume of renewable fuel, it will have surplus RINs that may be sold to other parties or banked for compliance with a portion of the following year's RVO requirement. Conversely, if an obligated party blends *less* than its required volume, it may purchase RINs from other parties to offset the shortfall, or it may carry a deficit forward to the next year.

Are merchant refiners required to buy RINs to comply with the RFS?

NO. While some merchant refiners argue they are "required" to purchase RINs from other refiners or blenders, the truth is they could have invested in renewable fuel blending infrastructure. This would have allowed them to blend required volumes of renewable fuel and capture RINs free of charge. Following passage of the expanded RFS in 2007, some refiners took steps to increase their renewable fuel blending capacity so they could capture RINs internally. Meanwhile, other refiners chose not to invest in blending capacity, choosing instead to buy RINs from parties who blended more than required.

Are RINs an unrecoverable "sunk cost" for refiners?

NO. It is well understood that refiners who buy RIN credits rather than blending ethanol recoup their RIN costs by slightly marking up the selling price of gasoline blendstock. Thus, RINs are not a "sunk cost" and do not negatively affect the financial performance of refining companies, both large and small.

- Oil industry firm **Turner, Mason & Company** agrees that RINs don't affect refining margins, stating, "RFS compliance costs are substantially passed from refiners" to wholesale gasoline buyers.
- The **Environmental Protection Agency** found that RINs are not negatively affecting profit margins for oil refiners. According to EPA, "…obligated parties, including small entities, are generally recovering the cost of acquiring the credits necessary for compliance with the RFS standards through higher sales prices of the petroleum products they sell."
- After conducting more analysis, **EPA** concluded "…refiners are generally able to recover the cost of RINs in the prices they receive for their refined products, and therefore high RIN prices do not cause significant harm to refiners."

- Economists from **Iowa State University** found "…added refiner costs from complying with the RFS are passed on to blenders through higher gasoline prices. We show that high RIN prices…have no impact on profits of refiners, blenders, or integrated oil companies."
- Refiner **Andeavor**, who merged with **Marathon** in 2018, stated "RIN costs are passed through at the bulk finished product sales points and provide refiners with coverage of their exposure to them."
- Even the **American Petroleum Institute** agrees: "RIN costs are largely recovered by refineries, large and small, through the increased value of gasoline and diesel fuel they supply to the market."

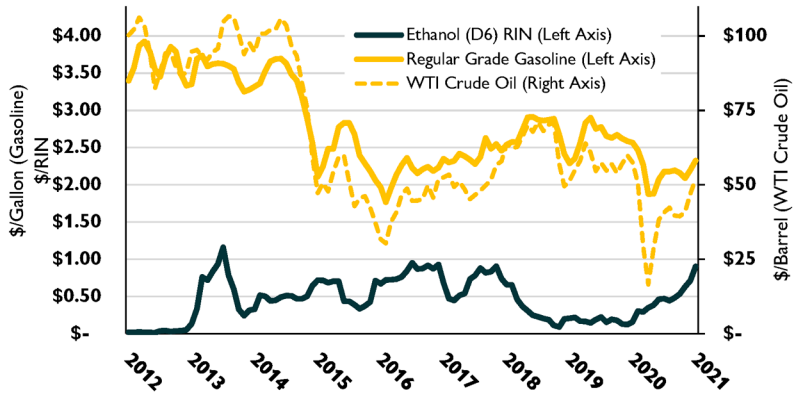
How do RINs impact wholesale fuel prices?

As noted above, RIN costs are passed through from refiners to wholesale purchasers, leading to slightly higher wholesale prices for gasoline blendstock. However, RINs have the opposite effect on renewable fuels, **lowering the cost of ethanol** for blenders. When ethanol is blended with gasoline to create a finished fuel, the RIN-enabled discount on ethanol fully offsets the RIN cost passed through on gasoline by refiners. For fuel blends that contain more than 10% ethanol (such as E15 or E85), the RIN enables a sufficiently larger discount that is typically shared with consumers in the form of lower retail prices.

Do RINs impact retail fuel prices at the pump?

NO. There is no evidence to support the notion that RINs push retail gas prices higher. In fact, RINs and retail E10 gas prices tend to be negatively correlated, with periods of high gas prices often occurring during periods of *low* RIN prices and vice versa. According to an **Iowa State** study, "…the net effect on the [retail] price of E10 of high RIN prices is zero: higher gasoline prices are offset by lower ethanol blending costs and the price of E10 remains constant."

Monthly Prices: U.S. Retail Gasoline, WTI Crude Oil, D6 RIN Credit



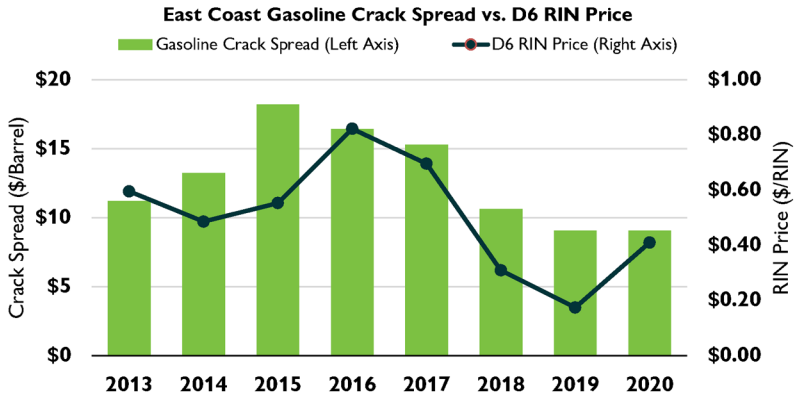
Source: OPIS and Energy Information Administration

How can there be no relationship between RINs and gas prices? EPA explains it this way: "When RIN prices rise, the market price of the petroleum blendstocks produced by refineries also rise to cover the increased RIN costs…**The effective price of renewable fuels, however, *decreases* as RIN prices increase**. When renewable fuels are blended into petroleum fuels these two price impacts generally offset one another…"

The primary driver of retail gasoline prices has always been crude oil prices—that has not changed in the RFS era. Between January 2012 and January 2021, retail gasoline prices are almost perfectly correlated with WTI crude oil prices (correlation coefficient of 0.96).

How have refiner profit margins been affected by RINs?

Contrary to the rhetoric coming from some in the refining industry, there is **no statistical evidence to support the argument that higher RIN prices negatively affect refiner margins or earnings**. In fact, the gasoline "crack spread" (a surrogate for refining margins) for East Coast refineries shows a modest positive correlation with RIN prices in recent years, meaning *refining margins are highest when RIN prices are highest* (this supports the argument that RINs are embedded in the refinery crack spread).



Source: RFA analysis of EIA and OPIS data

- Analysts from **Wells Fargo Securities** released an analysis in 2017 that examined the potential impacts of RFS compliance costs on merchant refiners, finding that "Most independent refiners now enjoy a net *benefit* from RINs, based on our analysis." The analysts also found that "RINs costs are being passed along" and "investors should not spend much time and effort" worrying about RINs.
- Refiners across the country have admitted that weaker refining margins in 2020 were due to COVID-19 and the dramatic collapse in fuel demand resulting from travel restrictions—not the RFS.

Did the wave of small refiner exemptions impact RIN stocks and RIN prices?

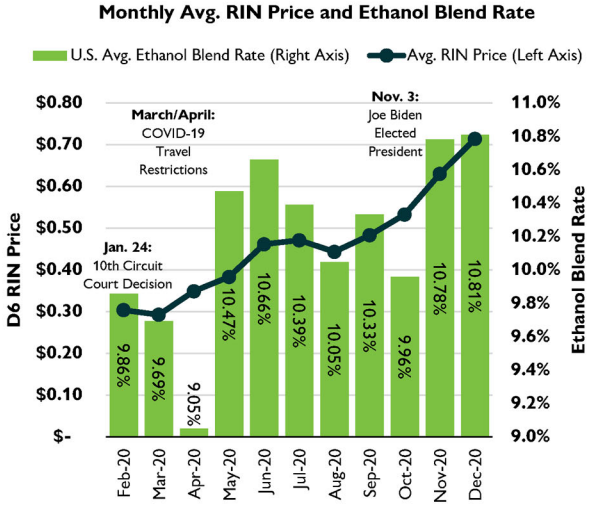
ABSOLUTELY. EPA's issuance of 86 small refinery compliance exemptions from 2016-2018 RFS requirements ballooned RIN stocks to more than 3.5 billion RINs. That is more than double the level of RIN stocks just a few years ago. Consequently, RIN prices plummeted from 95 cents in November 2017 to just 20-30 cents for most of 2018 and 2019, decreasing the incentive for blenders and refiners to increase volumes of E15 and flex fuels like E85 to push past the so-called E10 "blend wall."

What has happened with RIN prices recently?

RIN prices began to rise in late January 2020 following a decision by the 10th Circuit Court in *Renewable Fuels Association et al. v. EPA* that overturned certain small refinery exemptions. RIN prices gained more strength in the fall of 2020, following agricultural and energy commodity markets higher. The election of President Biden also served as a positive signal to the RIN market, as he has stated strong support for the RFS and publicly condemned the Trump administration's illegal small refinery exemptions.

Are higher RIN values leading to increased domestic demand for ethanol?

YES. As expected, higher RIN values are providing a strong incentive for refiners and blenders to increase their use of ethanol and other renewable fuels. In fact, as RIN prices rose in November and December 2020, the average ethanol content in U.S. gasoline reached record levels around 10.8%. This is evidence that higher RIN values are enabling larger sales volumes of E15 and flex fuels like E85 and facilitating greater discounts for consumers at the retail level.





Thanks to a meaningful RIN value, E85 was priced 45% below E10 ($1.19 per gallon less) at the Frontier station in Adams, Nebraska, on March 4, 2021.

Source: OPIS and Energy Information Administration

WHAT DRIVES RETAIL GASOLINE PRICES? NOT RENEWABLE FUEL STANDARD RINs

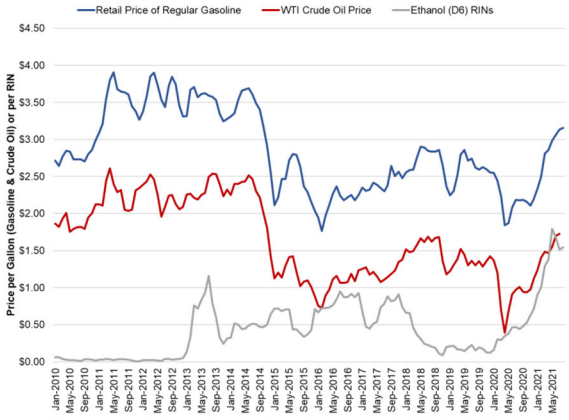
September 13, 2021

Retail gasoline prices hit seven-year highs this summer. Big Oil and its allies in Congress tried to divert attention from the real causes of the increase by blaming the cost of credits used to demonstrate compliance with the Renewable Fuel Standard (RFS), which are referred to as renewable identification numbers (RINs). Recently, a group of senators stated in a letter to the Environmental Protection Agency (EPA) that "high RIN prices are also contributing to the skyrocketing gas prices that our constituents are paying at the pump."[1] However, the truth is that the drivers of gasoline prices are the same as they have always been: crude oil prices and supply/demand factors.

Fundamental Drivers of Gasoline Prices

Crude oil prices are the predominant driver of retail gasoline prices. This is evident simply from looking at a historical chart (Exhibit 1).

Exhibit 1: Prices of Retail Gasoline, Crude Oil and RINs



Sources: EIA (gasoline and crude oil prices), OPIS (RIN prices)

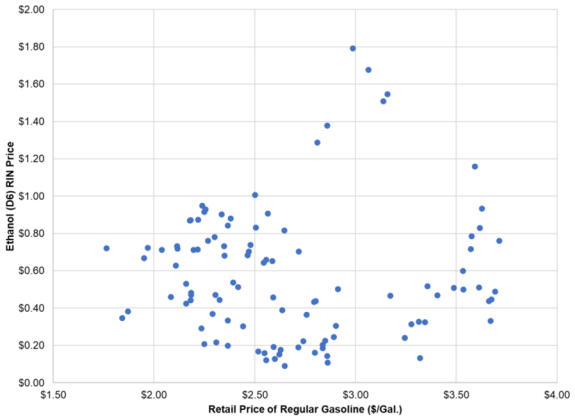
Retail gasoline prices have had a correlation of 0.96 with West Texas Intermediate (WTI) crude oil prices on a monthly basis from January 2013 to July 2021. This indicates a very

[1] Letter from Pennsylvania Senator Pat Toomey to EPA Administrator Michael Regan (August 23, 2021) https://www.toomey.senate.gov/imo/media/doc/epa_letter_8-23-21.pdf

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strong relationship, given that perfect positive correlation is 1.00. On the other hand, the correlation between gasoline prices and the prices of ethanol RINs (referred to as D6 RINs) has been -0.05, indicating virtually no relationship, as is reflected in Exhibit 2.

Exhibit 2: Regular Gasoline Retail Price vs. D6 RIN Price, Since Jan. 2013

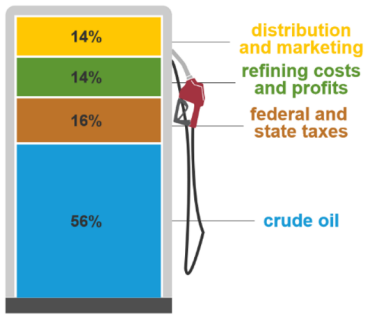


Sources: EIA (gasoline prices), OPIS (RIN prices)

What causes changes in gasoline prices? According to the U.S. Energy Information Administration (EIA), "Retail gasoline prices are mainly affected by crude oil prices and the level of gasoline supply relative to gasoline demand."[2]

The EIA estimates that the cost of crude oil accounted for more than half of what consumers paid for gasoline from 2011 to 2020, and crude oil and taxes together represented nearly three-quarters of the total (Exhibit 3). Costs and profits at the refining and distribution/marketing stages of the supply chain each accounted for 14%.

Exhibit 3: What Do We Pay Per Gallon of Retail Gasoline?



Note: Regular gasoline, 2011-2020
Source: EIA

[2] U.S. Energy Information Administration. (2020). "Gasoline explained: Gasoline price fluctuations." https://www.eia.gov/energyexplained/gasoline/price-fluctuations.php

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The Role of RINs

A RIN is generated when a gallon of ethanol is produced, and it is separated when the ethanol is blended, at which point it can be submitted for RFS compliance, held in inventory or sold. Obligated parties under the RFS (mainly refiners) can secure RINs by blending biofuels, or they can purchase RINs from other entities. A considerable body of research has shown that the *wholesale* price of gasoline incorporates the price of RINs, allowing refiners to recover their costs.

However, there is another step in the fuel supply chain that is important to understand. When ethanol is blended at the terminal and a RIN is separated, the RIN has value and can be sold (or retained if the blender is an obligated party). This value is used to offset the higher *wholesale* gasoline price that reflects the RIN cost to the refiner, and the net result is that the *retail* price of gasoline paid by consumers is essentially unchanged.

This has been acknowledged by the EPA: "When RIN prices rise, the market price of the petroleum blendstocks produced by refineries also rise to cover the increased RIN costs. . . . The effective price of renewable fuels . . . however, *decreases* as RIN prices increase. When renewable fuels are blended into petroleum fuels these two price impacts generally offset one another for fuel blends such as E10."[3] [EPA's emphasis.]

Analysis of Wholesale and Retail Gasoline Price Drivers

Regression analysis can be used to demonstrate whether and to what extent RIN prices affect gasoline prices at the wholesale and retail levels.

The EIA publishes the methods that it uses to forecast petroleum product prices. For gasoline, the process starts with a projection of the difference (spread) between the average U.S. motor gasoline wholesale price and the cost of Brent crude oil (wholesale prices are more strongly related to Brent than WTI crude oil prices). Per the EIA, "This wholesale gasoline margin is estimated as a function of the following variables:

- The change in the spot price of Brent crude oil;
- Inventory deviation from the previous four-year average;
- A trend variable starting in 2003;
- Monthly dummy variables;
- A lagged dependent variable."[4]

Notably, the price of RINs is not utilized by the EIA as an explanatory variable.

The RFA utilized EIA's approach to conduct analyses of wholesale and retail gasoline price spreads to Brent crude oil, with a few modifications:

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[3] U.S. Environmental Protection Agency. (2017). *Denial of petitions for rulemaking to change the RFS point of obligation.* Available at www.regulations.gov docket number EPA-HQ-OAR-2016-0544.
[4] U.S. Energy Information Administration. (2020). *Short-term energy forecasting petroleum product price module* (Handbook of energy modeling methods). https://www.eia.gov/analysis/handbook/pdf/STEO_Petroleum_Product_Prices.pdf

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- Modifications were made to the explanatory variables:
  - The ethanol (D6) RIN price was added;
  - The spread between Brent and WTI crude oil prices was utilized rather than the change in the Brent price, since it improved the results;
  - A dummy variable was added for March and April 2020 due to the impact of coronavirus-related lockdowns;
- The timeframe utilized was August 2010 - May 2021, since all necessary data were available for the period, including RIN prices.

The results were clear. The D6 RIN price change was a significant determinant (at the 5% level) of the price spread between wholesale gasoline and Brent crude oil, as were the other main explanatory variables (Exhibit 4). However, for the retail gasoline price spread to Brent, the D6 RIN price change was not significant, but the other main explanatory variables still were.[5] **In short, RIN prices are a factor in wholesale gasoline prices, but not in retail gasoline prices.**

Exhibit 4: Summary Statistics from Gasoline Price Regressions

	Wholesale	Retail
R Square	0.83	0.76
Adjusted R Square	0.80	0.73
Standard Error	0.06	0.09
F	31.5	22.3
	P-value	
Lagged Dependent Variable	0.000	0.000
Brent - WTI Spread	0.002	0.027
Total Gas Stocks - 4-Yr. Avg.	0.004	0.021
D6 RIN Price Change	0.027	N/S
Covid Dummy Variable	0.008	0.027

Notes:
Dependent variable for wholesale price analysis: U.S. regular gasoline wholesale/resale price by refiners - Brent crude oil price.
Dependent variable for retail: U.S. regular all formulations retail gasoline price - Brent crude oil price.
Other explanatory variables included: trend starting August 2010, dummy variables for January - November.
N/S = Not significant at the 5% level.
Sources: RFA (analysis), EIA (petroleum prices and stocks), OPIS (RIN prices).

Conclusion

Higher gasoline prices this summer were caused primarily by OPEC+ oil production cutbacks and an increase in gasoline demand. Additionally, supply disruptions such as the Colonial Pipeline shutdown and refinery closures due to Hurricane Ida accentuated price pressures at times. RINs are a convenient target for accusations since they are not widely understood, but as the analysis above confirms, RINs do not contribute to higher retail gasoline prices.

[5] The weighted average price across RIN categories, which is referred to as the RVO value, was tested in the wholesale and retail regressions, but it did not improve results compared to the D6 price.

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Clean Fuels
ALLIANCE AMERICA

Testimony of Clean Fuels Alliance America
Senate Committee on Environment and Public Works
Hearing to examine the Environmental Protection Agency's Renewable Fuel Standard program, focusing on challenges and opportunities
Wednesday, February 16, 2022

Dear Chairman Carper, Ranking Republican Capito, and Committee members,

This year, our organization (formerly the National Biodiesel Board) evolved to become Clean Fuels Alliance America. Our new name embraces the new products our members are producing and the markets they are building – including biodiesel, renewable diesel, sustainable aviation fuel (SAF), Bioheat® fuel, maritime and railroad fuels. Clean Fuels serves as the industry's primary organization for technical, environmental, and quality assurance programs and we are the strongest voice for its advocacy, communications, and market development.

During the past two years' economic challenges, our members worked hard to meet increasing U.S. demand for cleaner, better fuels. In 2021, the biomass-based diesel market grew to 3.2 billion gallons – its highest volume ever. This generated more than 4.8 billion advanced biofuel credits for the Renewable Fuel Standard program. During the pandemic in 2020, the market reached 3 billion gallons, generating more than 4.4 billion advanced biofuel credits for the RFS.[1,2]

Maintaining this supply of cleaner, better fuel is crucial right now. Demand for distillates – for heating oil, heavy duty transportation, shipping, manufacturing – continues to increase, putting pressure on inventories.[3] At the same time, the U.S. Department of Energy notes that distillate fuel inventories are currently about 19% below the five-year average for this time of year.[4] The shortage of distillates is a key supply chain bottleneck that is contributing to inflation that could trigger a recession.[5] U.S. oil refiners are simply unable to meet demand for cleaner fuels.

The Renewable Fuel Standard (RFS) is necessary to build domestic alternative fuel production capacity, bolster U.S. energy security, and address environmental health. It is succeeding.

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[1] U.S. Energy Information Administration Monthly Biofuels Capacity and Feedstocks Update. (January 31, 2022). https://www.eia.gov/biofuels/update/
[2] U.S. Environmental Protection Agency. (December 2021). Spreadsheet of RIN Generation and Renewable Fuel Volume Production by Fuel Type for the Renewable Fuel Standard. https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-rin-generation-and-renewable-fuel-0
[3] John Kemp, "Column: Depleted U.S. Distillate Stocks Show Supply Chain Pressure." Reuters, February 6, 2022.
[4] Energy Information Administration, Weekly petroleum Status Report, DOE/EIA-0208(2022-05), February 9, 2022.
[5] John Kemp, "Column: Diesel is the U.S. Economy's Inflation Canary." Reuters, February 9, 2022.

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Our industry is poised to continue to grow and innovate to meet the evolving needs of the fuel market. In on-road, off-road, air transportation, electricity generation, and home heating applications, we project that the market for low-carbon biomass-based diesel will exceed 6 billion gallons by 2030, eliminating over 35 million metric tons of CO_2 equivalent greenhouse gas emissions annually. With advancements in feedstock, use will reach 15 billion gallons by 2050.[6] We are pleased that EPA proposed sustainable growth opportunities in the RFS for 2022 that are consistent with industry expectations.

We advocate that EPA continue to grow volumes in the future, set volumes and rules in a timely and forward-looking manner, and ensure that once set, the volumes are met.

The United States will need low-carbon liquid fuels in the future to meet President Biden's climate goals.[7] Greenhouse gas reductions can start now in the heavy-duty and long-haul diesel sectors with increasing use of biomass-based diesel. Biomass-based diesel use lowers net lifecycle carbon emissions by 74 percent on average compared to petroleum fuel – and up to 88 percent in the most efficient plants. It also lowers particulate matter by 45 percent.[8]

In addition to being a solution to reduce greenhouse gas emissions, the U.S. biodiesel and renewable diesel industry supports 65,000 U.S. jobs and more than $17 billion in economic activity each year.[9] Every 100 million gallons of production supports 3,200 jobs and $780 million in economic opportunity.[10] Biomass-based diesel production supports approximately 13 percent of the value of each U.S. bushel of soybeans.[11]

Growth of Industry Capacity

The U.S. biodiesel and renewable diesel industry continues to expand, with consumption growing approximately 7% in 2021 relative to 2020. Domestic biodiesel and renewable diesel producers are increasing capacity to match.

Based on U.S. Energy Information Administration (EIA) data, there are 2.4 billion gallons of domestic biodiesel capacity and 1 billion gallons of domestic renewable diesel capacity as of November 2021.[12] Multiple expansions or new construction projects have been announced and the biomass-based diesel

[6] https://www.nbb.org/about-nbb/mission-vision
[7] Executive Office of the President. Executive Order 14008: Tackling the Climate Crisis at Home and Abroad, 86 FR 7619 (February 1, 2021), available at https://www.federalregister.gov/d/2021-02177
[8] California Air Resources Board. LCFS Pathway Certified Carbon Intensities. Fuel Pathway Table. Current Fuel Pathways. REG Albert Lea, LLC. https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities
[9] The Economic Impact of the Biodiesel Industry on the U.S. Economy. LMC International. August 2019. https://www.biodiesel.org/docs/default-source/federal-files/lmc_economic-impacts-of-biodiesel_august-2019.pdf?sfvrsn=ce27766b_2
[10] Id.
[11] Frizzell, R. (2019). NBB Static Biodiesel Shock. Frizzell, R. (2021). NBB Static Biodiesel Shock. INTL FCStone. Report.
[12] U.S. Energy Information Administration. (January 31, 2022). Monthly Biofuels Capacity and Feedstocks Update. https://www.eia.gov/biofuels/update/

industry is poised for significant growth over the coming decade. Depending upon market conditions, up to 1 billion gallons of renewable diesel capacity could come on-line during the 2022 calendar year.

In July 2021 EIA noted, "If all projects come online as intended, U.S. renewable diesel production would total 5.1 billion gal/y (330,000 b/d) by the end of 2024."[13] Since that EIA statement in July 2021, additional new projects have been announced.

It is important to understand that more than 70% of the current BBD market is met by biodiesel. As renewable diesel and SAF projects come online, Congress, the Biden administration and EPA must be careful not to abandon existing infrastructure investments or disincentivize production of biodiesel that is already addressing the climate crisis. If the goal is to achieve maximum carbon reductions, the market for biodiesel should be preserved, not simply shifted to different types of fuels.

RFS volumes should grow today and in the future to incentivize and account for the growing renewable diesel and SAF coming online.

Growth in Feedstock Supplies

Investments have extended throughout the supply chain, including the oilseed processing sector and feedstock refining/pretreatment. Over the past year, U.S. companies have announced more than 500 million bushels of soybean processing capacity to come online over the next three to four years, with approximately 16% of the new capacity or expansions slated to come online in 2022. These investments would generate additional feedstock supplies for almost 780 million gallons of biomass-based diesel.

U.S. soybean crush is anticipated to grow to 2.63 billion bushels by 2025; supplied by a combination of increased production in the U.S. (boosted by higher yields) and some shifts away from lower value export markets. Overall supplies are a combination of increased processing and a long-term trend of higher oil output per bushel. LMC International Ltd., an independent consulting firm specializing in the economic and market analysis of crops and agro-industrial products, projects soybean oil production in the US to increase to 30.8 billion pounds by 2025.

The U.S. market continues to grow while maintaining its historic feedstock diversity. In 2021, slightly more than half of U.S. produced biomass-based diesel used vegetable oils and the remaining came from animal fats, used cooking oil (UCO), and distillers corn oil (DCO). This diversity allows biodiesel and renewable diesel producers to alter feedstock use based on regional and global market dynamics. In the future, other sources will contribute to feedstock supplies. Advances are being made with new sources such as winter annual oilseed crops.

According to LMC, up to 1.866 billion additional gallons of biomass-based diesel could be generated from the additional feedstock supplies available during this time frame. [14]

Let the RFS Work

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[13] U.S. Energy Information Administration (July 29, 2021). U.S. renewable diesel capacity could increase due to announced and developing projects. https://www.eia.gov/todayinenergy/detail.php?id=48916#

[14] LMC International. (January 2022). The Outlook for Increased Availability & Supply of Sustainable Lipid Feedstocks in the U.S. to 2025. (Appendix A.)

EPA's recent proposal to retroactively adjust the 2020 volumes is unnecessary. Even with COVID-19 and delays in denying small refinery exemptions, obligated parties can comply with the standards finalized in late 2019 (and many have begun to do so). While transportation fuel demand fell in 2020 during the COVID-19 pandemic, the actual number of gallons of biofuel required under the RFS for 2020 decreased proportionally – because the volumes were set on time and translated into percentages. Based on EIA's most recent estimate of gasoline and diesel used in 2020, there are sufficient RINs for refiners to meet the obligation without changes – thanks in large part to the hard work of our members. If EPA retroactively reduces previously finalized volumes, it will erode confidence in the program and potentially cause further demand destruction.[15]

We agree with EPA's assessment that no refinery bears disproportionate RFS compliance costs, or a hardship created by compliance with the RFS program: "With no disproportionality and no economic hardship, there can be no disproportionate economic hardship pursuant to the statute."[16] But EPA must still account for any exemptions it could grant, since it has not made a final determination or settled inevitable litigation on pending exemptions.

If the agency reverses its accounting for potential small refinery exemptions, then our industry stands to lose demand for 147 million gallons of biomass-based diesel. When EPA retroactively grants exemptions, it returns credits to the system that then reduce demand for renewable fuels across the board in future years. The agency has not finalized its proposal to deny exemption petitions for 2019, 2020, and 2021, and it is in the process of reconsidering exemptions it granted in 2018. The agency also has not revealed the number of exemptions DOE recommended for those years and the associated volumes, per the methodology established in the 2020 rule.[17]

The RFS Reduces Greenhouse Gas Emissions Today

Emissions from diesel uses in rail, long-haul trucking, home heating, aviation, and maritime sectors are going to continue to increase as travel and trade return to pre-COVID19 levels. The RFS is helping companies drive decarbonization in their supply chains right now and it should be viewed as a primary tool of the Administration to reduce greenhouse gas (GHG) emissions now and meet President Biden's near- and long-term climate goals.

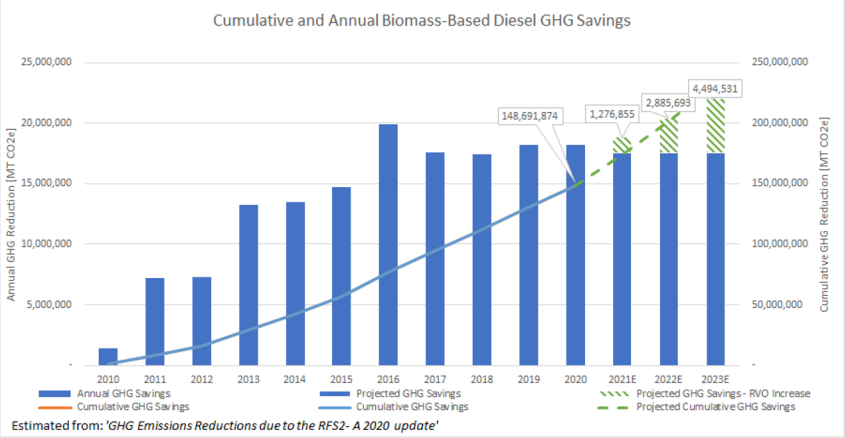
It is clear the program works to dramatically reduce emissions – even absent the projected volumes of cellulosic biofuels. Since the onset of the program, the RFS has reduced emissions by nearly a gigaton – far exceeding the 593 million metric tons estimated in the 2009 regulatory impact statement.[18] Since 2010, use of biodiesel, renewable diesel, and Bioheat® fuel has avoided an estimated 143.8 million metric tons of carbon (See Figure 1).

The most recent update to the Argonne National Lab Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model published in October of 2021 estimates that the *average*

[15] U.S. Environmental Protection Agency. Notice of Opportunity to Comment on Proposed Denial of Petitions for Small Refinery Exemptions, EPA- EPA-HQ-OAR-2021-0566, 86 FR 70999 (December 14, 2021), available at https://www.federalregister.gov/d/2021-26983
[16] Id.
[17] 85 Fed. Reg., 7052. Table VII B-1.
[18] Unnasch. S. and D. Parida (2021) GHG Reductions from the RFS2 – A 2020 Update. Life Cycle Associates Report LCA. LCA.6145.213.2021 Prepared for Renewable Fuels Association.

gallon of biodiesel and renewable diesel reduces emissions by approximately 74%. In addition, some producers are working through their supply chains to reduce emissions even further, including installing wind, solar, and other renewable energy onsite, creating fuel that reduces lifecycle emissions by 88%. Every 100 million gallons of biomass-based diesel added to the RVO is estimated to reduce emissions by over 600,000 MT annually.

Figure 1. Cumulative and Annual Biomass-Based Diesel GHG Savings



Estimated from: *'GHG Emissions Reductions due to the RFS2- A 2020 update'*

Biodiesel and renewable diesel are solutions that reduce carbon now. The immediate investment in a mature, currently commercialized biomass-based diesel fuel yields higher annual greenhouse gas emissions reductions than waiting for a technology that is still considered immature, such as EVs.[19] Increasing the use of biomass-based diesel now will provide immediate greenhouse gas reductions and a positive impact on health in disadvantaged communities.

Environmental Justice

In addition to reducing greenhouse gas emissions, advanced biofuels reduce particulate matter emissions. For every 100 million gallons of U.S. biodiesel and renewable diesel used today in place of petroleum, particulate matter is cut by approximately 252 tons. According to EPA and the California Air Resources Board, biodiesel and renewable diesel significantly reduce criteria pollutants from diesel transportation and heating oil. This benefits all populations, including minority, low-income, and indigenous populations.

Last year, Trinity Consultants presented a report that quantifies the health benefits and corresponding economic savings from converting petroleum-based diesel to B100.[20] The report estimated that

[19] Frank, Jenny & Brown, Tristan & Haverly, Martin & Slade, Dave & Malmsheimer, Robert. (2020). Quantifying the comparative value of carbon abatement scenarios over different investment timing scenarios.
[20] Trinity Consultants. (March 2021). Assessment of Health Benefits from Using Biodiesel as Residential Heating Oil. https://www.biodiesel.org/news-resources/health-benefits-study.

displacing diesel with biodiesel in communities with high diesel emissions rates could result in significantly improved health outcomes for the local population. In the 13 sites analyzed throughout the country, Trinity estimated that a switch from diesel to 100 percent biodiesel would avoid or lessen 240,000 asthma attacks, recover 46,000 lost workdays, and avert 1,100 cases of cancer – among other key benefits – generating a societal value of $3 billion dollars a year.[21]

In the transportation sector, benefits included a potential 44 percent reduction in cancer risk when heavy-duty trucks such as semis use B100, resulting in 203,000 fewer or lessened asthma attacks for the communities studied. When biodiesel is used for home heating oil, the study found an 86 percent reduced cancer risk and 17,000 fewer lung problems for the communities studied.

The American Lung Association has found that major trucking corridors, warehouse distribution centers and other diesel hot spots can inflict serious harms to human health, and often highlight disparities in the impacts of transportation pollution.[22] Biodiesel can make a difference now in reducing harmful tailpipe emissions that have this adverse impact. The RFS, when implemented in a timely manner will drive demand for higher blends of biodiesel resulting in direct public health benefits for disadvantaged communities.

Economic Impact

Increasing use of biomass-based diesel has a direct impact on the U.S. economy, including rural communities. The spending that comes with biodiesel and renewable diesel production on feedstock, other materials, goods, and services generates significant circulation throughout the economy. This stimulates demand, supports jobs, generates additional household income, and creates new tax revenue. LMC International estimated that, assuming a consistent rate of domestic production, the 3 billion gallons of biodiesel, renewable diesel, Bioheat® fuel, and sustainable aviation utilized in the United States in 2020 supported more than 79,000 U.S. jobs, $3 billion in wages paid, and $20.4 billion in total domestic economic impact. [23]

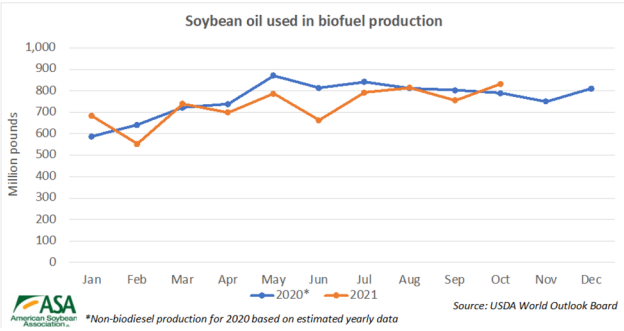
Although new demand for biofuels will generally support commodity values, the biodiesel and renewable diesel industries have increased volumes in conjunction with growth in feedstock supplies. Recent announcements of multiple new renewable diesel operations in the U.S. during the past year combined with commodity value inflation in 2021 have caused some to implicate biofuels as the cause for higher commodity values experienced in 2021. Actual data does not support this conclusion (See Figure 2). The USDA World Outlook Board confirms that use of soybean oil for biodiesel and renewable diesel production during the first ten (10) months of 2021 was actually lower than in the same time period in 2020 (7.62 billion pounds in 2020 versus 7.32 billion pounds in 2021). Supply chain issues and logistical constraints due to COVID-19, and inflation in fertilizer and fuel prices which are key inputs to crop production have all contributed to general inflation in all commodity prices (see Figure 3).

Economic analysis performed at Purdue University corroborates this point and concludes there is lack of any clear, consistent relationship between soybean oil prices and use of soybean oil in biofuel

[21] Id.
[22] American Lung Association. (2020). The Road to Clean Air.
[23] LMC International. (August 2019). The Economic Impact of the Biodiesel Industry on the U.S. Economy.

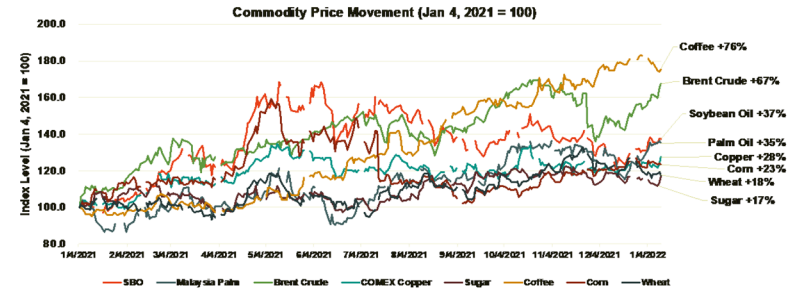
production.[24] Dr. Jayson Lusk notes, "Factors such as the global production and consumption of soybeans and soybean meal can, at times, have more definitive effects on domestic soybean oil prices."

Figure 2. Soybean Oil Used in Biofuel Production



Furthermore, this analysis conducted at Purdue University notes that soybean oil represents a small share of the cost of most retail food items. Dr. Lusk conducted a simple, pass-through analysis which indicated, "A 1% increase in the price of soybean oil is associated with a 0.026% increase in retail potato chip prices; a doubling of soybean oil prices (a 100% increase) would be associated with a 2.6% increase in retail potato chip prices. For white bread and chocolate chip cookies a 1% increase in soybean oil prices is only associated with a 0.0034% and 0.0184% increase in retail prices, respectively." Regression analysis with data from the 2011 to 2021 timeframe also concluded the relationship between changes in soybean oil prices and changes in the retail prices of food items (noted above) are small and difficult to precisely identify.

Figure 3. Commodity Price Movement (Jan 4, 2021 = 100)



Presented by Mac Marshall, United Soybean Board at Biodiesel Conference, January 2022

[24] Lusk, J. L. (2021). Soybean Oil Prices and Retail Food Costs. Center for Food Demand Analysis and Sustainability, Purdue University, for the United Soybean Board.

In order for biodiesel and renewable diesel to have a positive impact on the rural economy, consistent and timely implementation of the RFS as intended by Congress is essential for increasing production and use of clean, renewable fuels in the United States. The RFS deadlines are important not only to biodiesel and renewable diesel producers, but to all program stakeholders throughout the supply chain who rely on market signals from the annual rules.

President Biden made a commitment to maintain the integrity of the RFS program as a bond with farmers and with rural communities. In the past several years, EPA retroactively reduced RFS requirements through a flood of small refinery exemptions. That destroyed demand for more than a half billion gallons of biodiesel and renewable diesel. Demand destruction like this has a direct impact on the bottom line for farmers across America.

Any positive impact of the biodiesel and renewable diesel industry on the rural economy will be lost if EPA retroactively adjusts the 2020 volumes and creates uncertainty about future volumes. A retroactive reduction will result in less biofuel blending in future years – once again causing demand destruction and a lost market opportunity for biodiesel and renewable diesel feedstocks. While the retroactive reduction looks like a short-term fix, the impact of this action is far-reaching and will be most felt in the rural economy.

Sincerely,



Kurt Kovarik
Vice President, Federal Affairs
Clean Fuels Alliance America

Senator ERNST. Outstanding, thank you so much.

Just to address some of the issues that have been brought forward by our witnesses and members of the Committee as well. Just looking back at the average closing price of crude oil, in 2020, it was $39.68 a barrel, and the average closing price in 2022 so far is $85.72 a barrel. Today, it was $95.46 per barrel of crude oil.

Is that due to the RFS, to our witnesses?

Emily.

Ms. SKOR. I will go ahead and take that one.

Absolutely not. The primary factor in terms of the cost of fuel at the pump is going to be the cost of crude oil. It has nothing to do with the RFS.

Senator ERNST. Thank you, Ms. Skor. I think a point that our members are trying to make today is the cost of fuel is because of the RFS. It is not. It is about the price of oil. So, I reject that. I hope that our folks out there listening are paying attention to that. The price of our fuel is the price of the oil.

We have had the RFS around for a number of years, and the reason we have is because Congress asked for the RFS to be established so that we could reduce our greenhouse gas emissions. The folks across the Midwest, our farmers, our producers, responded to the call to Congress. And they developed systems that produce clean, reliable energy sources.

I also reject the premise that oil refineries and their rural communities are more important than my rural communities.

As we are looking to 2023 and beyond, America's farmers and the biofuel sector are best positioned to work with this Administration and others to put the Renewable Fuel Standard back on track and be part of the solution to secure a clean energy future. As much as the Biden administration dreams of an all electric world, the reality is, liquid fuels are here to stay. With 98 percent of cars and trucks today, and nearly 80 percent of new vehicle sales projected in 2050 running on gasoline or flex fuel, biofuel is the key pathway to decarbonizing the transportation sector, and the RFS is the policy engine that makes this possible.

Congress passed the Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007, which mandated the RFS, in part, to help reduce America's dependence on foreign nations. Folks, I firmly believe energy security is national security. And while President Biden claims to support America's clean energy economy, he is turning his back on the RFS in favor of electric vehicles, which will only make us more dependent on China.

Science is on our side here, too. Biofuel has enabled the U.S. to cut emissions from the transportation sector for over a decade. Between 2008 and 2020, the RFS saved nearly 1 billion metric tons of carbon dioxide equivalent greenhouse gas emissions, and it is only getting cleaner. The latest research shows corn ethanol is 46 percent less carbon intensive than petroleum based gasoline, and biodiesel is 74 percent less carbon intensive than petroleum based diesel.

Biofuel can further reduce greenhouse gas emissions with carbon capture and sequestration technologies and on farm conservation practices, which many of our Iowa farmers are already doing.

So let's follow the science and use biofuel as part of a clean energy policy, but it is not only the clean energy source. Biofuel is also great for our economy and our pocketbooks. Iowa corn and soybean farmers had record high crop yields in 2021. The biofuel industry accounts for over $5 billion of GDP, generates $2.6 billion of income for households, and supports nearly 46,000 jobs in Iowa alone, in my rural areas.

Ethanol is also the cheapest form of fuel for consumers right now, by about 50 cents, and certainly with record high inflation, it only makes sense to make this fuel source more readily available.

That is why I continue to urge the Administration, allow summertime sales of E15 as soon as possible. It will not only support our consumers, it will also support the nearly 300 retail stations in Iowa who want to provide a cleaner choice at the pump.

Folks, the RFS is the law, and refiners have had over 15 years to come into compliance. Blend renewable fuels or buy RINs. It is your choice. Any claim that RIN prices are increasing gas prices, it is a bunch of hogwash. Refiners claim they need exemptions because RINs cost them money, but the last three Administrations have said RIN prices do not cause harm to refiners.

Small refinery exemptions go against congressional intent, and the Supreme Court reinforced this. A strong RFS supports rural America and increases consumer access to affordable, home grown, clean burning biofuel today, tomorrow, and we also hope, for many years to come.

Thank you. I will yield back.

Senator CARPER. Thanks, Senator Ernst. Thanks for your attendance; thanks for your patience, and your questions and comments.

Several members and witnesses asserted that the increase of gasoline at the pump is attributable to crude oil prices. So I asked my staff, I said, well, let's actually look at the numbers. If you go back to February 2021, the price of oil at the pump was $62.28. The price today is roughly $94 per barrel. That is an increase of about 51 percent. Those are interesting numbers.

I have a couple of questions, and Senator Capito, you may have some wrap up questions as well.

Before we do that, Senator Wicker, Roger is going to try to get here. Maybe he is joining us remotely.

Senator Wicker, are you out there anywhere?

No, he is not going to be able to come. OK, thanks.

A couple of questions. The first one that I would like to ask, Ms. Wind, with respect to eligible fuels, unlike the Renewable Fuel Standard, which requires eligible liquid and gaseous fuels and electricity to be derived from renewable biomass sources, low carbon fuel standard programs, like Oregon's, are generally intended to be both fuel neutral and technology neutral. With this in mind, the Oregon Clean Fuel Program has a broader definition of transportation fuels than the Federal Renewable Fuel Standard.

My question, Ms. Wind, is how has this broader definition of transportation fuels benefited the Oregon program, and how has this encouraged investment in producing cleaner fuels in your State?

Ms. WIND. Yes, thank you for that question, Senator Carper.

That is true. The State of Oregon, with the low carbon fuel standard, we do basically value any of the transportation fuels that are lower carbon than gas and diesel. So in addition to the biofuels and electricity, we also do have renewable natural gas. We have propane and renewable propane, and we are going to be investing more in hydrogen, as well.

What we would like to see is that, even with natural gas and with propane, that we switch from the fossil versions to the renewable version. But even the switch from say, fossil gasoline or fossil diesel, there are benefits from the propane and the natural gas. If those are the fuels that, because of the lower cost of those fuels, are what is leading to more infrastructure, more vehicles in the alternative fuel space, and then switching to the renewable versions lowers the carbon intensities even more, those are the kinds of things that we also see in the State of Oregon and will likely continue to see as we move into the future for the Oregon Clean Fuels Program.

Senator CARPER. OK, thanks, Ms. Wind.

I have a follow up question also to Ms. Skor.

Ms. Skor, with restrictions on what qualifies as an advanced fuel under the Renewable Fuel Standard, could a technology neutral program, like Oregon's Clean Fuels Program, allow more opportunity for your member companies to participate in the current structure of the Renewable Fuel Standard?

Ms. SKOR. Thank you for the question.

Yes, we are a low carbon fuel, so we do very much appreciate the concept of a low carbon fuel standard. Importantly, as you stated, Senator, making sure that this is technology neutral. This is where the carbon modeling comes into play. We have to make sure that you are evaluating the full life cycle analysis of biofuels like ethanol, that you are considering all of the low carbon farming practices that continue to bring down the carbon intensity of our fuels.

If you have a program that is truly technology neutral, that reflects the current state of the art science and the innovation taking place throughout industry, that allows for use of higher biofuel blends, like an E15, that is a place where we can play and I think will be able to really help in terms of achieving some of our collective low carbon goals.

I will add that that is a very complementary to the RFS, so the two programs work well in tandem. I think Ms. Wind talked earlier about that value stack, to continue making sure the lowest of the low would go into a market like in Oregon.

Senator CARPER. I have two more quick questions, two more quick ones, and then I am going to yield to Senator Capito. We have a vote underway as well.

This is a question for the entire panel. I appreciate the perspectives, I think we all do, that our panel has shared with us today. I want to compliment our staffs for pulling you all together. Thank you for joining us in person and remotely. I hope that this dialogue can help inform thoughtful action to support the future of this important program.

With that said, I also recognize the challenges in forging a path forward for the Renewable Fuel Standard that satisfies everyone and the potential need for compromise and collaboration.

In closing, I just want each of you to take just half a minute, if you will, and tell us where you believe there might be common ground for all of us on this panel as we deliberate this issue going forward, and we will.

Ms. Skor, would you like to go first?

Ms. SKOR. Certainly, thank you.

I heard a lot of consensus about the importance of competition, about the importance of marketplace certainly, and the importance of consumer choice as we make sure that we drive toward low carbon fuel options for consumers that are affordable and available. This is a place where biofuels really have a role to play.

What we need is a Renewable Fuel Standard that is enforced so there is some certainty, and those making business decisions throughout the fuel supply chain, including agriculture, biofuels, and on the refining side, so we understand what the obligations are, and we bring down that volatility.

We look forward to seeing the EPA fix and finalize the blending obligations for 2020 and 2021 and 2022 as expeditiously as possible. That kind of certainty is going to be something that is going to be good for all parties.

Senator CARPER. Thank you.

Senator Ernst, do you have one more question?

Senator ERNST. Thank you, Mr. Chair.

Just very briefly, because I think I have gotten most of the answers for my questions. But I would like, Ms. Skor, Emily, would you respond, give a statement or thoughts on the anti-ethanol study that was done earlier this week?

Ms. SKOR. I appreciate the comment, thank you. Yes, I am familiar with that. It is really very concerning when you look at the manipulation of the science and data, the unorthodox methodology that leads to really, fictitious and erroneous conclusions.

In short, you have a piece of work that is untethered from reality. You look at the totality of science and the consensus of EPA, Department of Energy's Argonne National Labs, California Air Resources Board, Oregon's Department of Environmental Quality, and of course, many academicians and scientists. Ethanol is lower carbon than gasoline, and that advantage continues to increase.

Senator ERNST. Thank you, Ms. Skor.

Thank you, Mr. Chair.

Senator CARPER. Sure.

Senator Capito has one last question, then I want to ask the remainder of my time to go to three of our witnesses, and then we will wrap it up.

Senator Capito.

Senator CAPITO. Thank you, Mr. Chairman.

Yes, I do have to run really quickly after I just make a comment or two. It has been a very interesting hearing. I think there is consensus that there is a lack of certainty. Maybe certainty in different areas that you might share different areas that don't have certainty, but you are looking to us to provide some of the certainty, so that EPA can move forward.

In my view, nothing screams lack of certainty than having an exemption that is then revoked 2 years later. That, to me, is just unconscionable, no matter what it is happening to, if it was a corn

producer, if it was a refiner, if it is a coal miner. Anything, an EV car maker, if you have the OK, and it says that you are going to have the permit to move forward, how can you possibly conduct business if somebody is going to come back 2 years later and revoke it? I think that, to me, is lack of certainty.

I do have the study here that shows, from the University of Wisconsin, that U.S. corn based ethanol is worse for the climate. I am not going to argue that. I don't know. I think that we need to get what is a life cycle, when does it start, how long does it go, what kind of emissions are included in producing ethanol from corn or growing corn or getting crude out of the ground. I think we need to have some consistency here and certainty here that we are using the same measurement data, because I think it confuses the American public, quite frankly, and many of us here who are making those decisions.

I just want to thank you, Mr. Chairman. I don't really have a question. I just thank the witnesses for being here for us, and I thought our members asked some really good questions. Thank you.

Senator CARPER. Yes, it has been valuable. This Committee, as you know, is pretty good at finding the middle in the complex, difficult issues, unanimously in some cases. This is a hard one. We look forward to working with your team and others that are on this Committee trying to find a path forward going forward.

I like to say if it isn't perfect, make it better. This situation is not a perfect situation. We have got to do better than this. Thank you.

I am going to go back to our panel again. I would ask a question I call a common ground question. I would ask each of you to take a minute to let us know where you believe there is common ground among all of you. I think only Ms. Skor has the opportunity to respond, so let me just ask our other witnesses if they would respond, as well.

Ms. Wind, why don't you go first? Common ground.

Ms. WIND. Thank you for the question, Senator Carper. I think I would, yes, common ground, echo what Ms. Skor and Ranking Member Capito have mentioned, uncertainty. It is something that we hear quite a bit from the stakeholders that participate in the Oregon Clean Fuels Program and in the market. Certainty, as far as regulatory certainty, as far as the standards being established for our program, that is why we are undertaking our current rulemaking now to expand those standards out to 2035 to provide that certainty.

I think along with certainty, transparency in what we do in the way that we do our life cycle accounting and the bonding and the information that is used to establish those carbon intensities, as well as the market aspects of our program, the credit pricing and the transactions for that. It is something that is the pillar of how we implement the program in Oregon, and I think, has served us really well.

Senator CARPER. Thank you, ma'am.

Mr. Pugliaresi.

Mr. PUGLIARESI. Yes, thank you, Mr. Chairman. I was thinking, one of the problems is maybe we should try to do a better job of getting a common set of facts.

Senator CARPER. Sometimes that helps.

Mr. PUGLIARESI. Yes, sometimes it helps.

I think that one of the things I would like to ask the Committee to do is, let's have the Energy Information Agency publish data for us on what the FOB export price of gasoline is and what the wholesale domestic price of gasoline is. Let's have them break down the components, because there is a lot of discussion of crude oil is causing prices to go up. Of course it is, but there are other components in the manufacturing of transportation fuels.

I think if we could get them to do a little more work on this, we might get some consensus or a sense of where are the hotspots, so to speak, beyond crude oil, that are driving up gasoline prices.

Senator CARPER. Good, thank you for that suggestion.

Ms. Koch, same question.

Ms. KOCH. I think common ground is that small refineries do not oppose biofuels, so biofuels that are lower emitting are not a problem. Where we depart is on the ability of everybody to share in the ability to blend or pay unreasonably high RIN prices.

But I would say that we have commonality in wanting lower emitting biofuels. Where we depart on that point also is on whether or not ethanol is, in fact, a lower emitting fuel. Because as we have been talking about, the recent studies suggest that ethanol could be 24 percent higher emitting of greenhouse gas emissions than petroleum based fuels.

To Mr. Pugliaresi's point, information is key. Senator Ernst explained that blending is a choice. It is not a choice when you don't have access to biofuels. So I think the EIA could help us enormously by instead of resisting Freedom of Information Act requests related to how much is each refinery paying to buy RINs, what is each refinery's actual cost of compliance.

We understand that sufficient RINs are available for compliance, but not in the hands necessarily of the people who need them for compliance. Whose hands are they in? So more forthcoming data would certainly help to dispel, maybe, some of the disagreements. I think that that would be important.

There are substantial barriers to blending, which I agree with Ms. Skor, there are. I think we disagree as to what those barriers are, but there are substantial barriers. We have to have a change to the Renewable Fuel Standard if we want it to be sensible, if we want it to not distort competition, and if we want to bring down the price of gasoline and diesel.

Senator CARPER. Thank you.

I have a real quick question for Ms. Skor. I am going to ask you to just be very brief in your response, because we have a vote underway, and I don't want to miss that vote.

Ms. Skor, it is my understanding that the previous Administration significantly increased the number of small refinery waivers it issued compared to the Obama administration, including issuing waivers for refineries owned by integrated companies like ExxonMobil. Is that your understanding?

Ms. SKOR. That is correct, Mr. Chairman. In the previous Administration, EPA increased the number of small refinery exemptions by a factor of six. That was a sixfold increase. Over 80 small refinery exemptions resulted in 4 billion gallons of demand destruction, and without any information or transparency, in the theme of information, as to how it is that they determined that those particular refiners met the very narrow threshold that is, you have got to demonstrate disproportionate economic harm as a result of RFS compliance.

We are pleased to see that this EPA is taking a different approach and really looking to follow the law and the narrow scope of that relief avenue, which is available.

Senator CARPER. Thank you for that response.

In closing, let me just say, we have had great participation here, certainly from the witnesses, but also from the members in person and remotely. I am grateful for all of that. I am grateful to our staffs for pulling together a great panel.

This is not an easy issue. It is the first time we have had a hearing on it in almost 6 years. And it is long overdue. It has been helpful for me, and I hope it has been helpful for some of my colleagues. We have raised as many issues and questions as we have answered, but it is a good start.

Again, this is one of the hallmarks of this Committee, as we work together, and we work across party lines, we try to get to yes as often as we can and find consensus.

I want to thank you all for joining us today. If done correctly, renewable fuels help safeguard our Nation's energy security, boost economic opportunity for farmers, and reduce greenhouse gas emissions. I look forward to continuing our conversation and working with members of our Committee, our colleagues in the Senate, and other stakeholders to improve the Renewable Fuel Standard Program. And as we look to the future of the program, I believe we can encourage even greater sustainability for the fuels that empower our lives.

Before we adjourn, some housekeeping. Senators will be allowed to submit written questions for the record through the close of business on Wednesday, March 2nd.

We will compile those questions, panel, and we will send them to you. We will ask you to respond, if you will, by Wednesday, March 16th.

With that, this hearing is adjourned. Thank you.

[Whereupon, at 12:02 p.m., the hearing was adjourned.]

[Additional material submitted for the record follows:]

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Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States



Low carbon fuel standards, such as the Federal Renewable Fuel Standard and the California Low Carbon Fuel Standard, are major U.S. programs for reducing greenhouse gas (GHG) emissions from transportation fuels. These standards rely on life cycle assessment (LCA) as a tool to estimate fuel GHG emissions. However, current LCAs differ notably in how they are implemented, with disagreements pertaining to data quality, modeling approaches, and key assumptions. This methodological assessment aims to develop a reliable and coherent approach for applying LCA to low carbon fuel standards.

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Description

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An ad hoc committee of the National Academies of Sciences, Engineering, and Medicine will assess current methods for estimating lifecycle greenhouse gas (GHG) emissions associated with transportation fuels (liquid and non-liquid) for potential use in a national low-carbon fuels program. In carrying out its assessment, the committee will identify the general characteristics and capabilities of GHG emissions estimation methods that would be commonly needed across various types of low-carbon fuels programs applied at a national level. The committee will include these considerations:

• GHG emissions over the entire lifecycle of a given transportation fuel, including feedstock generation or extraction, feedstock conversion to a finished fuel or blendstock, distribution, storage, delivery, and use of the fuel in vehicles.

• Potentially significant indirect GHG emissions.

• Key assumptions, input parameters, and data quality and quantity, including spatial variability, for application of lifecycle GHG emission models

• Needs for additional data, methods for data collection, standardized inputs for lifecycle analyses, and model improvements.

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- WILL THE COMMITTEE ADDRESS EMERGING LOW CARBON TRANSPORTATION FUELS?
- WILL THE COMMITTEE ENDORSE A METHOD OR MODEL FOR LIFE CYCLE ASSESSMENT OF LOW CARBON TRANSPORTATION FUELS?
- WILL THE COMMITTEE CONSIDER FUELS THAT ARE PRODUCED OUTSIDE OF THE UNITED STATES?
- WILL THE COMMITTEE CONSIDER INDIRECT GREENHOUSE GAS EMISSIONS THAT ARE PRODUCED OUTSIDE OF THE UNITED STATES?
- WHEN DOES THE COMMITTEE MEET?
- CAN I ATTEND A COMMITTEE MEETING?
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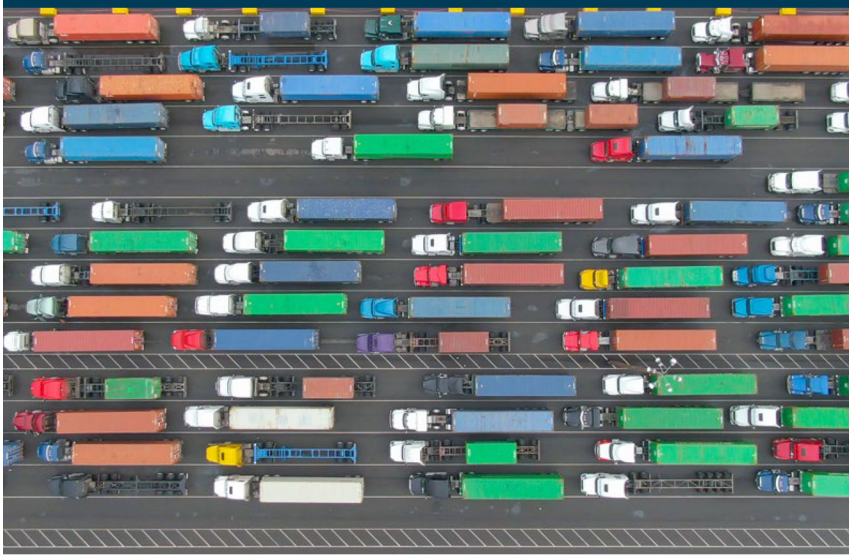
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JANUARY 15, 2021



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Closing the Transportation Emissions Gap with Clean Fuels

JANUARY 15, 2021

By Emily Wimberger, Trevor Houser, and John Larsen

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About this Report

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Executive Summary

Federal and state policies adopted over the past two decades have done a great deal to bend the curve of greenhouse gas (GHG) emissions from the US transportation sector. However with 1.6 billion tons of CO_2-equivalent projected to come from the transportation sector in 2030, we are still a long way from being on track to net-zero emissions by 2050, or from reducing transportation-related pollutants like NOx, particulate matter, and ozone, which disproportionately impact communities of color and low-income communities.

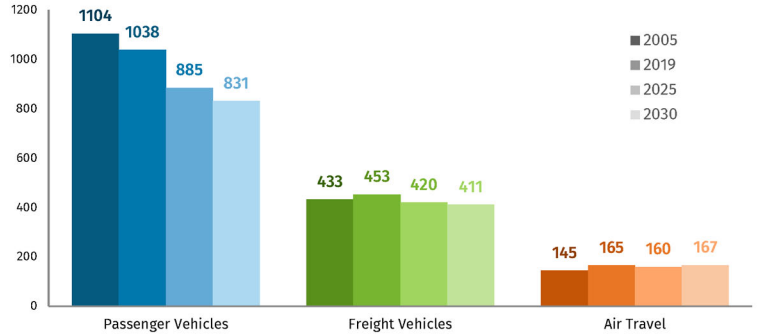
To achieve economy-wide net-zero emissions, we find that, in the transportation sector, a portfolio of strategies is the lowest cost and most likely to succeed. While efficiency improvements and vehicle electrification can cut transport emissions by up to two-thirds by 2050, low-GHG liquid fuels are needed to fill the remaining gap and achieve net-zero emissions in the transportation sector by mid-century.

Transportation will continue to be one of the largest sources of US emissions

Transportation is the largest source of GHG emissions in the US, accounting for 33% of the economy-wide total in 2019. While transport emissions declined 6% between 2005 and 2019, the majority of reductions have come from the passenger vehicle fleet (light-duty vehicles). Between 2005 and 2019, emissions from freight vehicles rose 5%, and aviation emissions rose by 14%.

Looking forward, under current policy, passenger vehicle emissions are projected to be 20% lower in 2030 than they were in 2019, largely due to increased electrification. However, the same progress is not projected for freight transportation and air travel. Freight emissions are projected to decline by 9%, while aviation emissions are expected to increase by about 1% in 2030 (ES Figure 1).

ES FIGURE 1
US transportation emissions by mode, 2005-2030
Million metric tons (MMT) of CO_2-equivalent (CO_2e)



Source: Rhodium Group. Projections are from Rhodium Group's Taking Stock 2020, V-shaped economic recovery scenario.

Electric vehicles alone will not get the US to net-zero by 2050

Under a scenario of modest electrification of light-duty vehicles (LDVs), we project that over 700 million metric tons of emissions will remain in 2050, from fuels that need to be decarbonized or displaced through mobility strategies that reduce vehicle usage (low electrification in ES Figure 3). Under this scenario, electric vehicle sales come in at the lower end of aggressive projections, reaching 35% of LDV sales in 2030 and 77% in 2040. Even with increased LDV electrification (ES Figure 2), where more than half of all LDV sales nationally are electric by 2030 and nearly 90% by 2035, 525 million tons of GHG emissions, 34% of emissions still remain in the transportation sector in 2050. The remaining emission reductions will need to come from fuel decarbonization and mobility solutions. Increasing mobility will reduce vehicle miles traveled but cannot decarbonize the remaining emissions from the transportation sector. Clean fuels will be needed to close the transportation emissions gap.

A portfolio of clean fuels is needed to close the transportation emissions gap

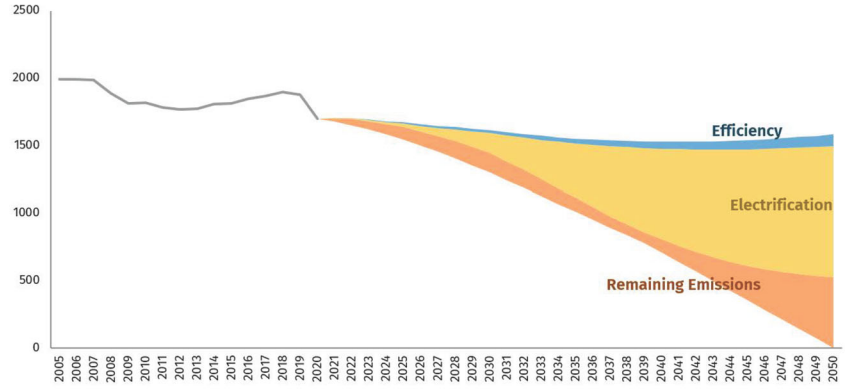
Achieving net-zero emissions in the transportation sector in 2050 will require not just electrification but other strategies as well, including aggressive federal action to deploy a portfolio of clean fuels. We find in our modeling that a combination of advanced biofuels, electrofuels, and carbon-neutral fossil fuels (defined in ES Table 1) can successfully close the transportation emissions gap and get the sector to net-zero emissions by 2050.

The optimal portfolio of clean fuels will depend on technology cost, feedstock availability and will vary regionally based on local air quality issues, availability of high-quality wind and solar resources and characteristics of the local agricultural economy.

ES FIGURE 2

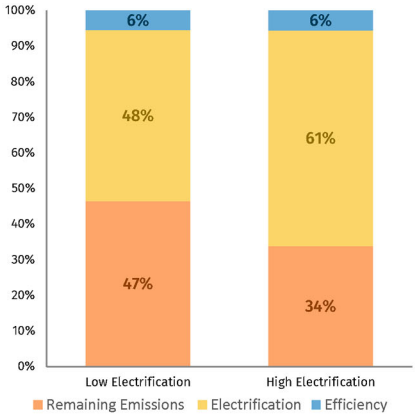
US transportation emissions with decarbonization strategies under a high electrification scenario

Million metric tons CO_2e



Source: Rhodium Group and EER

ES FIGURE 3
Transportation emissions fuel gap in 2050 under varying levels of electric penetration
Percentage in million metric tons CO_2e



Source: Rhodium Group and EER

ES TABLE 1
Clean fuel categories

Biofuels	Conventional and advanced fuels made from biomass feedstock
Electrofuels	Drop-in liquid replacement fuels made from electricity, carbon, and hydrogen
Carbon-neutral fossil fuels	Petroleum fuels whose emissions are offset with negative emissions technology

Federal policies to drive clean fuel deployment

Achieving net-zero emissions in 2050 will require aggressive federal action to reduce transportation demand, electrify vehicles, and develop and deploy clean fuels. A portfolio of policies can drive emissions reductions across transportation modes and amplify reductions from policies enacted at the state and local level. The federal government plays a large role in determining the US fuel mix. Research funding, fiscal incentives, market-based policies, and GHG and air quality targets all shape the portfolio of fuel consumed across the country. Rather than relying on existing policies, the federal government can take action to accelerate the deployment and market penetration of the clean fuels needed to achieve net-zero emissions by 2050.

Federal transportation policy should support research and development of clean fuels through funding and investments in transformational fuel technology. Moreover, the federal government can accelerate deployment and development of clean fuels through fiscal incentives aimed at fuel manufacturers and fuel consumers to incentive the production and consumption of clean fuels. Federal procurement policies can also increase market penetration as bulk purchases can increase economies of scale. Ultimately, deep market penetration of clean fuels, required to achieve net-zero emissions by 2050, will require durable price signals and robust federal policies.

This report begins with projections of transportation emissions under current policy, to identify the emission reductions that will be needed to achieve net-zero emissions by 2050. Next, we identify the portfolio of strategies that can achieve net-zero transportation emissions, including a wide range of clean fuels to complement electrification, efficiency, and increased mobility. The report then shifts to the economic and environmental merits of a wide range of clean fuels and the federal policy tools that can drive development and market penetration of clean fuels to achieve net-zero transportation emissions by 2050.

CHAPTER 1

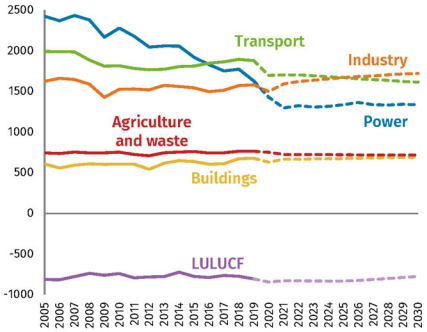
Current Transportation Emissions Trends

Transportation is the largest source of greenhouse gas (GHG) emissions in the US, accounting for 33% of the economy-wide total in 2019. Following decades of steady growth, transport emissions peaked in 2005 at just under 2 gigatons, and declined 6% between 2005 and 2019 (Figure 1). Much of the reduction came from the drop in vehicle miles traveled (VMT) during the 2008-2009 Great Recession, but policy and technology change have played an important role. Improvements in vehicle efficiency and increased biofuels deployment reduced the carbon intensity of US transportation by 14% since 2005, enough to offset the recovery in VMT after the end of the Great Recession. Emissions of other air pollutants have declined as well. While not yet a meaningful contributor to overall transportation emission reductions, electric vehicle (EV) sales are growing quickly, from 10,000 vehicles in 2011 to 330,000 in 2019. The overwhelming majority of transportation emission reductions have come from the passenger vehicle fleet. Between 2005 and 2019 emission from freight vehicles rose 5% and aviation emissions rose by 14% (Figure 2).

Transportation will remain a leading source of US GHG emissions through 2030.

Transportation was the sector that was most significantly impacted by the COVID-19 pandemic this year, as Americans dramatically curtailed driving and flying, particularly in the first half of 2020. Both passenger vehicle usage and air travel started to recover during the second half of the year, but the ultimate impact of COVID-19 on transportation emissions will depend on the pace of economic recovery in 2021 and beyond, and the permanence of pandemic-induced changes in mobility patterns (e.g. more working from home and more virtual conferences). In our 2020 Taking Stock report, we project US emissions by sector under a range of economic recovery scenarios. In our V-shaped recovery scenario, we expect transportation emissions to remain relatively flat between 2021 and 2030 as continued improvements in fuel efficiency and electric vehicle sales offset post-pandemic growth in vehicle miles traveled (Figure 1).

FIGURE 1
US emissions by sector
Million metric tons (MMT) of CO_2-equivalent (CO_2e)



Source: Rhodium Group. Projections are from Rhodium Group's Taking Stock 2020 V-shaped economic recovery scenario.

These projections include all current federal and state policy as of May 2020, including the federal Renewable Fuel Standard (RFS), updated heavy-duty vehicle GHG emissions standards, and federal vehicle incentives. We assume light-duty CAFE standards increase 1.5% annually from model year 2021 to 2026 following the Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule finalized in February 2020 for all states except California and the 14 S177 states that plan to maintain more stringent Obama-era CAFE standards. Our projections also include state-level Low-Carbon Fuel Standards in California and Oregon.

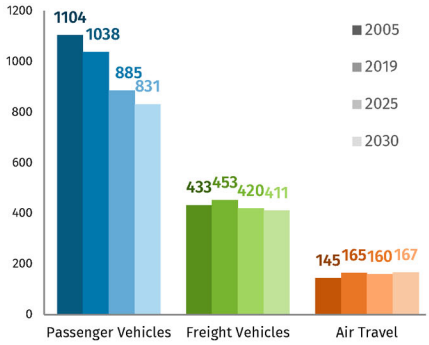
As over the past decade, most of the projected reductions in transportation emissions over the coming decade come from light-duty vehicles (cars and light

trucks). In our V-shaped recovery scenario, VMT grows by 9% between 2021 and 2030, but this is offset by a 15% improvement in the average efficiency of on-road vehicles as newer, higher efficiency cars and light trucks make up a larger share of the overall fleet. EVs also start to have a measurable impact on transportation emissions over the coming decade. Using battery cost projections from NREL's Electrification Futures Study (rapid advancement scenario), we project that the EV share of LDV sales grows to 17% in 2030 and that EVs account for 6% of total LDV stock that year. These are the assumptions included in our projections shown in Figure 1. Combining growing EV sales, continued improvements in vehicle efficiency, and lingering effects of the pandemic, we project LDV emissions will be 20% lower in 2030 then they were last year (Figure 2). Using more aggressive battery cost decline projections from Bloomberg New Energy Finance, EVs grow to 30% of new LDV sales by 2030 and 11% of total LDV stock. Under this scenario, LDV emissions decline by 22% instead of 20%.

FIGURE 2

US transportation emissions by mode, 2005-2030

Million metric tons (MMT) of CO_2-equivalent (CO_2e)



Source: Rhodium Group

Under current policy we expect significantly less progress in decarbonizing freight transportation and air travel over the coming decade. In our V-shaped recovery scenario, we expect both freight and aviation emissions to remain relatively flat (Figure 2). Improved efficiency in both trucks and planes helps offset growth in usage, but unlike in LDVs, it is not enough to lead to a net emissions decline.

Federal and state policy adopted over the past two decades, along with encouraging technological and market developments, have done a great deal to bend the US transportation emissions curve. But with 1.6 billion tons of CO_2e still projected to come from the transportation sector in 2030, we are still a long way from being on track to net-zero emissions by 2050—President-elect Biden's economy-wide goal—or from reducing transportation-related pollutants like NOx, particulate matter and ozone, which disproportionately impact low-income communities and communities of color. A multi-pronged policy approach that includes efficiency, vehicle electrification, and clean fuels, is needed to close the GHG emissions gap and address environmental health disparities.

CHAPTER 2

Paths to Net-Zero Emissions by 2050

To help inform a multi-pronged policy approach to decarbonizing the transportation sector, Rhodium Group partnered with Evolved Energy Research (EER) to model economy-wide pathways to achieving net-zero GHG emissions in the US by 2050. We used EER's coupled RIO/EnergyPATHWAYS modeling platform calibrated to technology cost and market inputs defined by Rhodium and consistent with Rhodium's Taking Stock 2020 baseline emission projections.

Economy-wide, we find that a six-part strategy is necessary to get to net-zero emissions:

1. **Efficiency:** Reduce the amount of energy required to fuel the economy by making appliances, buildings, equipment, and vehicles more efficiently.

2. **Zero-carbon electricity**: Decarbonize electric power generation by switching from uncontrolled coal, oil, and natural gas to renewables and nuclear and/or fossil generation with carbon capture and sequestration.

3. **Electrification**: A zero-carbon electricity grid provides a power platform for decarbonizing other sectors of the economy through electrification of appliances, equipment, and vehicles.

4. **Fuel decarbonization:** For those applications where appliance, equipment, or vehicle electrification is too costly, too slow, or faces significant barriers to adoption, decarbonized liquid and gaseous fuels made from biomass or zero-carbon electricity are necessary to close the gap.

5. **Other sectors and gases**: The energy sector accounts for 85% of US GHG emissions. The other 15%, like agricultural and methane or F-gas emissions, will need to be addressed through sector and/or gas-specific strategies.

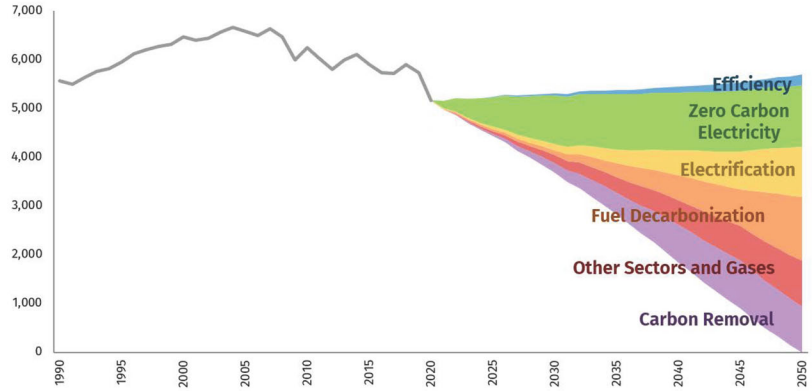
6. **Carbon removal**: Those emissions that can't be reduced directly will need to be offset by natural (e.g., improved forest management) or technical (e.g., direct air capture) carbon removal.

An illustrative combination of these strategies is provided in Figure 3. The ultimate balance among them depends on future technological, market, behavioral and policy developments. But what's clear from our modeling is that a multi-pronged approach is both the lowest cost way to get to net-zero emissions, and the one most likely to succeed.

A three-pronged strategy for decarbonizing transportation

For the transportation sector, three of the six economy-wide strategies apply. The US needs to a) reduce transportation energy demand through vehicle efficiency improvements and reductions in vehicle usage, b) electrify vehicles wherever possible and affordable, and c) develop and deploy low-GHG liquid fuels to cover the remainder. In modeling paths to net-zero emissions for the transportation sector, we explore the potential role played by all three.

FIGURE 3
Paths to economy-wide net-zero emissions in the US, by strategy
Million metric tons CO_2e



Source: Rhodium Group and Evolved Energy Research

Efficient mobility

The most direct way to reduce emissions from transportation is to move people and goods more efficiently—either by improving the fuel economy of cars, trucks, buses, ships and airplanes, or reducing how many miles those vehicles need to move people or goods. For this exercise, we only model the former, but the latter is equally important. We restrict internal combustion engine sales to only the most efficient vehicles available to create an upper bound estimate on the role fuel economy improvements can play in the transition to a net-zero economy. We do not include policies or investments that reduce demand for vehicle transportation, such as those that encourage switching to public transit, biking, walking, and micromobility, and those that improve freight logistics efficiency. These measures are outside the scope of this exercise and warrant a separate analysis to understand the potential reductions from increased mobility options.

Vehicle electrification

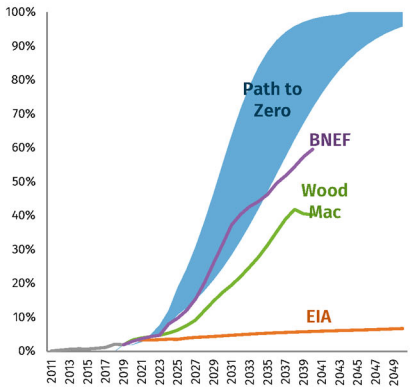
After a couple of false starts historically, electric vehicles have finally achieved escape velocity. Lithium-ion battery prices have fallen by nearly 90% since 2010, and based on current battery price projections from Bloomberg New Energy Finance (BNEF), electric vehicles in many vehicle classes will be cheaper than internal combustion engine vehicles within the next few years, even without subsidies. BNEF projects EVs will account for 10% of US LDV sales in 2025 (up from 2% in 2019), 32% in 2030 and 60% in 2040 (Figure 4). Wood Mackenzie has a slightly less aggressive forecast, with EVs reaching 6% of US LDV sales in 2025, 17% in 2030 and 40% in 2040. The EIA has the most conservative EV sales forecast, at 3.5% of sales in 2025, 5% in 2030 and 7% in 2040. This is largely a function of relatively outdated battery cost projections. When we run Rhodium's version of the same National Energy Modeling System (NEMS) used in EIA's forecast, but with updated battery cost projections, we get sales shares in 2030 between 17% and 36% depending on the specific battery price path.

In modeling transportation pathways to net-zero emissions, we adopt a range of EV sales projections that are more aggressive than the most optimistic current market forecasts, but within the realm of technical possibility. In the most optimistic case for LDVs, we model EV sales shares as high as 56% in 2030, 88% in 2035, 98% in 2040 and 100% from 2045 onward (Figure

4). Because of the time it takes for vehicles already on the road to turn over, there is a significant delay in these scenarios between growth in the EV share of vehicle *sales* and commensurate growth in the EV share of vehicle *stock*. But at the upper end, this still translates into market penetration rates for EVs in the years ahead as rapid as cell phones and the internet achieved in years past (Figure 5).

Under a scenario of high EV market penetration, EV adoption rates in 2030 would need to be equivalent to adoption rates for cell phones and the internet in 2005, 10 years after take-off.

FIGURE 4
US electric vehicle sales as a share of total LDV sales
Percent

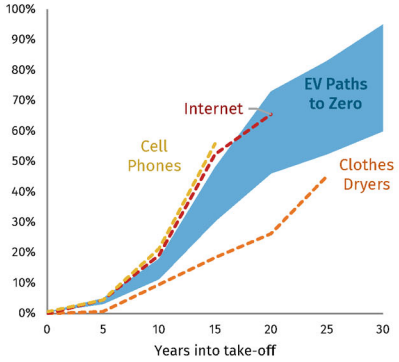


Source: Rhodium Group, EER, Bloomberg New Energy Finance, Wood Mackenzie, EIA

This analysis focuses on the electrification of the light-duty vehicle fleet given the current technological challenges with electrifying other transportation applications—specifically marine and aviation. Technology and cost have been barriers to development and deployment of electric airplanes and shipping vessels, which will require new policies to drive investment to achieve market penetration.

EVs face a number of barriers to wide-spread adoption that consumer electronics don't face even after they have achieved cost parity with internal combustion engines. These include infrastructure barriers like wide-spread charging station availability, behavioral barriers like range anxiety, and manufacturing scaling and supply chain barriers that are larger in the automotive industry than in consumer electronics. Aggressive action can help overcome these barriers, but not completely eliminate them. As a result, we also consider slightly less aggressive EV sales pathways in our modeling, but still more aggressive than BNEF projections from 2035 onward (Figure 4). In our slowest deployment scenario, EVs cross 50% of LDV sales in 2036 (instead of 2030 in our fastest case) and cross 90% in 2046 (instead of 2036).

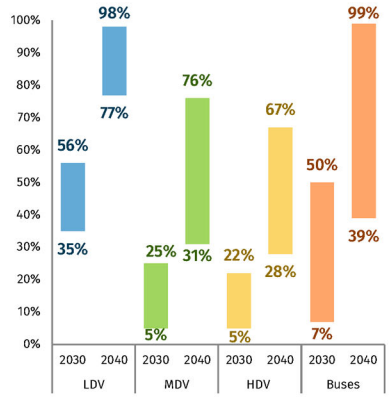
FIGURE 5
EV market penetration will need to match historic consumer electronic deployment
Percent of market in the years following take-off, EVs are LDV only



Source: Rhodium Group and EER

Electrification is occurring more slowly in the medium-duty vehicle (MDV) and heavy-duty vehicle (HDV) segments. For MDVs we assume between 5 and 25% of all sales are electric by 2030 and between 31 and 76% by 2040. For HDVs we assume between 5 and 22% of all sales are electric by 2030, and between 28 and 67% by 2040. We expect transit buses will be easier to electrify, and assume 7 to 50% of all sales are electric in 2030, growing to 39 to 99% by 2040 (Figure 6).

FIGURE 6
US electric vehicle sales as a share of total sales
Percent



Source: Rhodium Group and EER

Even with aggressive EV sales rates – 56% of LDV sales in 2030 and 98% of sales in 2040 - the US vehicle fleet is slow to electrify. Under our highest EV sales rates, EVs comprise only 18% of the LDV vehicle fleet in 2030 and 66% in 2040.

Fuel decarbonization

For those transportation applications where vehicle electrification is too slow, too expensive, or faces insurmountable market or behavioral barriers, low-GHG clean liquid fuels need to fill the gap. Fortunately, electrifying vehicles is not the only way to take advantage of increasingly low-cost renewable electricity to decarbonize the transportation sector. Electrolysis can be used to turn wind and solar power into hydrogen, which can be further transformed into electrofuels that can be used in existing cars, trucks, ships and planes. Advanced biofuels offer another low-GHG alternative to gasoline, diesel and jet fuel, as do carbon-neutral fossil fuels where negative emissions technologies are employed to offset emissions from conventional fossil fuels (Table 1).

To model the potential role for these different low-GHG fuels to play in reducing transportation sector emissions to zero, we explored a range of electrolyzer and direct air capture costs, as well as a range of levels of biofuels feedstock availability.

TABLE 1
Clean fuel categories

Biofuels	Conventional and advanced fuels made from biomass feedstock
Electrofuels	Drop-in liquid replacement fuels made from electricity, carbon, and hydrogen
Carbon-neutral fossil fuels	Petroleum fuels whose emissions are offset with negative emissions technology

In our modeling, we take electrolyzer cost estimates from the International Energy Agency. But we also explore a side case where electrolyzer costs are at the high end of currently available literature estimates. For direct air capture, we use technology cost estimates from a 2019 Rhodium Group report, Capturing Leadership: Policies for the US to Advance Direct Air Capture Technology. For biomass, we assume 850 million metric tons of available supply, at cost curves specified in the US Department of Energy's 2016 Billion-Ton Report. But we also explore a side case where no energy feedstocks are used for biofuels.

The US needs a mix of all three approaches

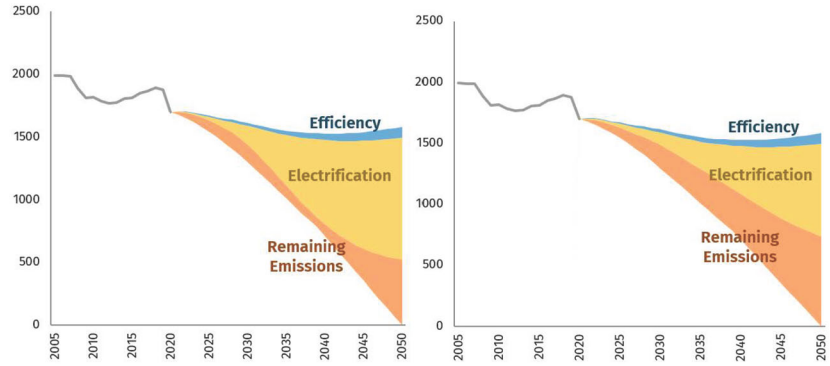
Decarbonized fuels and mobility options will need to comprise nearly half the emissions reductions needed to achieve net-zero emissions by 2050.

As in modeling economy-wide pathways to get to net-zero emissions, when we model what's required in the transportation sector specifically, we find that a portfolio of strategies is the lowest cost and most likely to succeed. Efficiency improvements and vehicle electrification cut transport emissions by two-thirds in 2050 in our most aggressive electrification scenario (assuming the power sector is completely decarbonized), leaving 525 million metric tons of remaining emissions (Figure 7 left).

FIGURE 7

US transportation emissions with decarbonization strategies under high and low electrification scenarios

Million metric tons CO_2e, high electrification scenario (left) and low electrification scenario (right)



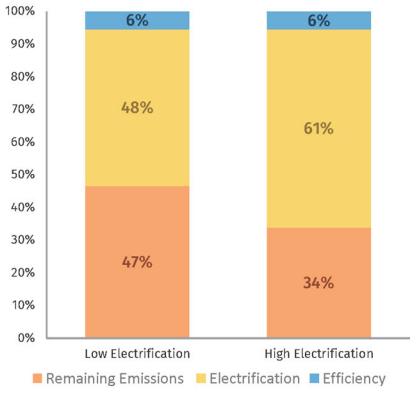
Source: Rhodium Group and EER

If electric vehicle sales come in at the lower end of our projections (but still higher than current BNEF projections), remaining emissions are 735 million tons in 2050 (Figure 7 right). Across the range of EV penetration scenarios, a gap of 34-47% of 2050 transportation sector emissions remains (Figure 8). Without low-GHG liquid fuels to fill this gap, there is little chance the US will be able to achieve net-zero transportation emissions by mid-century.

FIGURE 8

Transportation emissions fuel gap in 2050 under varying levels of electric penetration

Percentage in million metric tons CO_2e



Source: Rhodium Group and EER

CHAPTER 3

Clean Fuels

Fortunately, we find in our modeling that a combination of biofuels, electrofuels and carbon-neutral fossil fuels can successfully close the transportation emissions gap and get the sector to net-zero emissions by 2050. These low-GHG "clean fuels" all have a lower carbon intensity (CI) than fossil fuels (Text Box 1). The optimal balance among the various clean fuel options will depend on the cost of electrolyzers, the price of direct air capture and the availability of suitable biomass feedstock. It will also vary regionally within the US based on local air quality issues, availability of high-quality wind and solar resources and characteristics of the local agricultural economy.

Biofuels

Biofuels are transportation fuels made from a wide spectrum of biomass that are typically placed into two main classifications, conventional and advanced. Biofuel production is currently among the most technologically ready and cost-effective pathways to decarbonizing aviation, marine, and heavy-duty vehicle applications and achieve net-zero emissions by 2050. Conventional, or first generation, biofuels are liquid fuels that are commercially available and have reached technological maturity made from food crops and agricultural waste including corn, soybean, sugarcane, vegetable oil, and used animal fats. Advanced biofuels are derived from non-food crops and agricultural and forest residue through a variety of biologic, thermal, and chemical processes. Advanced biofuel feedstocks include algae, municipal solid waste, animal fats, and woody biomass composed of three primary elements: cellulose, hemicellulose, and lignin. Conventional and advanced biofuels can be blended with petroleum fuels, combusted in existing internal combustion engines, and distributed through existing fuel infrastructure.

The most common biofuels are ethanol and biodiesel that can be blended at various levels with gasoline and diesel, respectively. In the US, ethanol is produced mainly from corn through fermentation and biodiesel is produced from soybeans through transesterification. These fuel pathways are well-integrated in the agricultural sector with established technologies and

BOX 1

Measuring the carbon intensity of liquid fuels

Carbon intensity (CI) is defined as the amount of carbon emissions released per unit of energy produced. For transportation fuels, CI is the measure of GHG emissions emitted through the production and total life of the fuel, measured in grams of carbon dioxide equivalent (CO_2e) per megajoule (MJ). Fuel CI is based on the effects of five GHGs: CO_2, methane, nitrous oxide, volatile organic compounds, and carbon monoxide. The cumulative effect of these gases is calculated using life cycle analysis (LCA) which estimates the direct GHG emissions of fuels including emissions from: feedstock generation or extraction; conversion of feedstock to finished fuel or blendstock; distribution; storage; delivery, and final use of the fuel.

Argonne National Lab's GREET (Greenhouse Gases, Regulated Emissions, and Energy use in Transportation) model is considered the state-of-the-art model with over 100 pathways for petroleum fuels, natural gas fuels, biofuels, hydrogen, and electricity for analyzing the life cycle emissions of traditional and advanced technology fuels. The GREET model is frequently updated and is widely used by state and federal regulators and provides a uniform, transparent platform for LCA analysis with inputs from US Department of Energy, US EPA, US Department of Agriculture and other sources. GREET been used in the development of US EPA's Renewable Fuel Standard (RFS) and a California specific modification, CA-GREET was developed by the California Air Resources Board (CARB) for use in the Low Carbon Fuel Standard.

Indirect emissions, including emissions from indirect land use change (iLUC), are estimated separately and added to the CI calculation resulting in a comprehensive estimate of a fuel's lifecycle GHG emissions. As land is converted for biofuel feedstock, carbon stored in the soil and vegetation may be released. This iLUC factor is measured as the carbon emissions per unit of biofuel released due to global land use change from biofuel-induced changes in land and food prices. Both US EPA and CARB require the inclusion of iLUC factors for the CI calculations in the RFS and LCFS. There is a large body of literature estimating the iLUC factor of crop-based biofuel but fewer studies on non-crop and residual feedstock biofuels. ILUC factors and their application have been controversial and heavily litigated.

supply chains. Advancements in feedstock generation and processing continues to reduce costs, expand the range of co-products (including high quality animal feed) and improve the environmental performance of conventional biofuels.

More than 98% of gasoline in the US contains ethanol, with E10 (10% ethanol) the most common blend, used in conventional internal combustion engines. E15 (containing 10.5% to 15% ethanol) can also be used in conventional vehicles while E85 (85% ethanol) can only be used in flex fuel vehicles. In 2019, ethanol comprised 10% of US total gasoline volume, approximately 1.5 billion gallons. The energy content of ethanol is about 30% lower than gasoline, and a vehicle using E10 will on average see a decrease in vehicle fuel economy of around 3%. However, ethanol has a higher octane number than gasoline, increasing its power and performance, and researchers are investigating ways to optimize engine efficiency for higher-octane biofuel blends.

There are two main biofuels created from non-food and waste crops: renewable diesel and sustainable aviation fuel (SAF). These fuels are generated through gasification, pyrolysis, and hydrotreating processes that are in the early stages of development. When coupled with bio-energy with carbon capture and storage (BECCS), these advanced biofuels have the potential to be carbon negative.

To date, renewable diesel has gained the largest market share of advanced biofuels, and can be blended with diesel or used a drop-in replacement. In the US, five plants have a combined capacity to produce nearly 400 million gallons of renewable diesel each year. However, in 2019, about 900 million gallons of renewable diesel were consumed in the US, about 2% of total diesel volume. Nearly all US produced and imported renewable diesel was consumed in California due to the price signal of its Low Carbon Fuel Standard (LCFS).

Nearly 400 million gallons of renewable diesel are produced in the US each year.

SAF encompasses all non-petroleum jet fuels that were previously known as renewable jet fuel, alternative jet fuel, renewable aviation fuel, and biojet fuel. SAF can be blended with petroleum jet fuel at a maximum blend level of 50% across five fuel pathways. SAF has been used commercially since 2016, with 2.4 million gallons (less than 1% of aviation fuel demand) consumed in the US in 2019.

Carbon intensity of biofuels

Biofuels often rely on renewable feedstocks that could be used for other purposes—including food for human consumption, animal feed, and electricity generation. Increasing demand for biofuel feedstock can result in indirect land use change (iLUC), additional GHG emissions from the release of carbon sequestered in soil and vegetation as land is converted for biofuel feedstock. Studies vary widely in their iLUC estimates; however US EPA and CARB require the inclusion of iLUC factors in the CI calculations of biofuels.

The CI of biofuels can vary widely based on feedstock, production process, and fuel delivery, from carbon negative advanced biofuels with BECCS to ethanol that provides an incremental CI improvement due to iLUC. Conventional biofuels are largely blend fuels, limiting the fossil fuel emissions they can displace. Ethanol pathways, on average, have a CI approximately 40% lower than gasoline, while biodiesel has an average CI roughly 60% lower than diesel. Coupling conventional biofuel with soil carbon sequestration, biochar production, or BECCS does have the potential to further reduce the carbon intensity of finished clean fuels. Researchers estimate that an average corn ethanol plant can reduce the CI of ethanol by 40% through carbon capture, producing ethanol with 80% lower GHG emissions than fossil gasoline.

Advanced biofuels have a larger CI reduction potential as they can completely displace petroleum fuels. The average gallon of renewable diesel has a CI 60% lower than diesel, while SAF pathways average 65% lower than jet fuel. Advanced biofuels coupled with carbon sequestration even have the potential to be carbon negative. In September 2020, the Proceedings of the

National Academy of Sciences (PNAS) published findings that advanced cellulosic biofuel production with BECCS could achieve up to 15 times the carbon mitigation potential of forest or grassland restoration.

Corn ethanol plants can reduce the carbon intensity of ethanol by 40% through carbon capture.

Feedstock availability of biofuels

The availability of consistent feedstock has been a major factor in the supply of clean fuels. Feedstocks comprise a significant portion of the final fuel price for many fuels—up to 90% for some biofuels. Conventional biofuels have been subject to the 'fuel vs. food' debate, where critics argue that diverting cropland for fuel production increases crop prices leading to global food insecurity—often pointing to spuriously correlated movements in the price of corn and ethanol production. Advanced biofuels produced from non-food crop feedstocks do not directly compete with food crops for land use, however they can have iLUC factors due to changes in water and pesticide consumption. In addition, these advanced biofuel feedstocks often require additional processing compared to conventional biofuel feedstocks, increasing the overall cost of the final fuel.

In addition to land use changes, crop feed stocks may impact water and soil quality through use of additional fertilizer and pesticides. The Department of Energy's 2016 Billion-Ton Report estimates that the US has the potential to produce nearly 100 billion gallons of biofuel by 2030. In addition, the International Energy Agency (IEA) estimates up to 1.5 billion tons of advanced biomass (forestry resources, agricultural residue, and waste) will be available in the US in 2040. Advanced biofuels have the advantage of abundant and diverse feedstocks, but they require extensive processing relative to conventional biofuels. In addition, feedstocks may be located far from processing facilities and have immature supply chains, creating inconsistencies in quality and timing of finished fuels.

Despite the large potential for biofuel production, disagreements over iLUC factors could threaten widescale biofuel penetration. While some say sustainability standards can improve biodiversity and ecosystem benefits from biofuel feedstock, others voice concerns that increasing conversion of productive land for biofuels will divert scarce resources, causing harm. Increased demand for palm oil as a feedstock has been blamed for increased deforestation and reduced biodiversity in Indonesia. There have also been reports of human rights abuses associated with the harvesting of palm oil, leading some jurisdictions to consider banning the feedstock for use in biofuels.

Air quality impacts of biofuels

Every step in the life cycle of a fuel results in air quality impacts. For fossil fuels, this includes extraction, refining, fuel storage and transport, and combustion. Petroleum extraction, refining, and combustion releases oxides of nitrogen (NOx), particulate matter (PM), carbon monoxide (CO), sulfur dioxide (SO_2), volatile organic compounds (VOC) and carcinogens. NOx and VOCs react with sunlight to create ozone, a main ingredient in smog, while PM are fine particles that cause lung damage. Diesel particulate matter (DPM) is of particular concern as it also contains over 40 cancer-causing substances and is often emitted near highly populated areas.

Localized air pollution leads to adverse health effects including increased instances of asthma, cardiovascular disease, cancer, and premature mortality. The impact of air pollution is highly dependent on where it is emitted, and the relative impact of fuels depends on the location of feedstock production and processing and fuel combustion. Petroleum emissions can also exacerbate existing health conditions in vulnerable populations and communities of color. The average Black and Hispanic Americans are 41% and 46% more likely to be exposed to DPM than white Americans.

The emissions profiles of clean fuels vary greatly—by feedstock, processing and combustion—and quantifying air quality impacts, specifically in regions that fail to meet EPA National Ambient Air Quality

Standards for PM and ozone, is of critical importance to ensure that clean fuels result in GHG and air quality benefits.

Ethanol and biodiesel have a similar air quality profile to petroleum fuels. While studies have found some evidence that blending biodiesel with conventional diesel may lower the particulate matter of the fuel, there is a lack of consensus that blending ethanol with petroleum products results in any air quality improvements.

The air quality impacts of advanced biofuels vary by feedstock, conversion technology, and direct and indirect land use changes but generally offer lower criteria pollutant levels than petroleum fuels or conventional biofuels. The air quality impacts are separated by location of feedstock cultivation and production and fuel combustion. Combustion of advanced biofuels results in lower PM emissions than their fossil fuel counterparts which can provide health benefits in areas where the fuels are consumed. However, feedstock cultivation and processing can result in increased PM levels in regions where fuels are produced. Analyses have shown that renewable diesel in particular can have PM levels 30% lower than diesel. Renewable natural gas can also provide air quality benefits specifically when paired with low NOx engines that reduce combustion emissions relative to fossil fuels. However, there are concerns about NOx air quality impacts at production and processing facilities, which can reduce the net benefit of the finished fuel.

SAF has been shown to provide significant air quality improvements, including large reductions in sulfur oxides (SOx) and PM, across all fuel production pathways when blended with or replacing fossil jet fuel. SAF does not provide reductions in NOx emissions, however, which comprise a large portion of the overall health impact of the fuel.

Technology readiness of biofuels

Ethanol and biodiesel are largely produced using mature technological processes—hydrolysis and fermentation—that are proven on a commercial scale. Technologies to produce renewable diesel and SAF are more nascent and have been hampered by high capital costs. Advanced biofuel development has largely been driven by government support for research and development and fiscal production incentives. However, this support has not been sufficient for highly anticipated fuels, including cellulosic feedstocks, the microbial conversion of woody biomass to bioethanol and thermochemical processes to create renewable gasoline and diesel renewable gasoline, to reach production quantities. BECCS technologies, including thermochemical conversion and post-energy conversion carbon capture are also not yet mature, despite policy support.

Along with fuel development, technological advancements continue in the storage and transport of biofuels in order to maintain fuel quality across a range of climate conditions. Technological advances in conventional biofuels are now focused on efficiency, reducing overall production costs and maximizing the energy potential of feedstocks. Researchers continue to explore higher biofuel blends as well as off-road applications for drop-in biofuels.

Economic implications of biofuels

In 2019, the US imported an average of 9.1 million barrels of oil per day, a little less than half of domestic daily oil consumption. Displacing petroleum with clean fuels reduces our reliance on international oil supplies and can drive growth in domestic fuel production and distribution. Clean fuels can provide a just transition for workers and communities reliant on oil and gas extraction and production and provide direct economic benefit to low-income and historically disadvantaged communities through infrastructure investments and high-road employment opportunities. The diversity of clean fuel categories provides for economic opportunities across the US, promoting growth in urban and rural communities across occupations including science, engineering, construction, and agriculture.

Expanding consumption of biofuels will require additional feedstock and processing capacity which can

drive investment and employment in agriculture, science, engineering, and construction. Research and development of higher blends of ethanol and biodiesel can also drive employment and provide investment opportunities across the US. In 2019, there were 102 operating biodiesel plants and 201 ethanol plants in the US. Biodiesel plants were forecasted to operate at 77% of nameplate capacity in 2019, while ethanol plants were forecasted to produce more than stated operable levels.

The diversity of emerging advanced biofuel feedstocks and applications also presents a large opportunity for domestic investment and employment opportunity. Historically driven by government mandates, the demand for advanced biofuels has increased in recent years across transportation modes. The global aviation industry has committed to reducing GHG emissions by 50% from 2005 levels by 2050, increasing demand for SAF. While, currently there is very limited production of SAF in the US, low oil demand has led oil companies, including Phillips 66 and Marathon, to convert refining facilities to produce biofuels including renewable diesel, renewable gasoline, and SAF.

Electrofuels

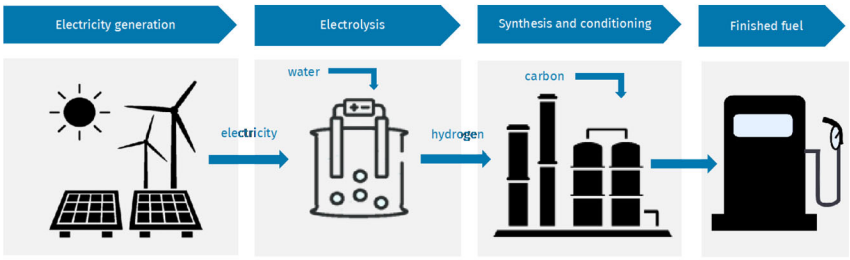
Electrofuels, or power-to-gas/liquid/fuel or synthetic fuels, are carbon-based drop-in replacement fuels produced from carbon and hydrogen, using electricity as the primary source of energy. The term electrofuels describes the process used to produce the fuel, rather than the fuel itself. Electrofuels can be similar or identical to fossil-based fuels.

Electrofuels are fuels produced using electricity, carbon, and hydrogen, which can replace fossil fuels.

The production of electrofuels requires electricity and CO_2. Electrofuels are produced through electrolysis where electricity is used to split water into oxygen and hydrogen. The hydrogen is then combined with carbon to form liquid hydrocarbons. The final fuels produced through this process include methane, methanol, and Fischer-Tropsch fuels depending on the catalyst used in the synthesis process (Figure 9). Fischer-Tropsch fuels include synthetic gasoline, diesel, and jet fuel, which are promising pathways to displace fossil fuels and drive deep decarbonization.

The emissions profile of electrofuels is determined by the sources of electricity and carbon used to create the fuel. Coupling carbon from direct air capture or BECCS coupled with renewable electricity can result in zero-carbon, or even carbon-negative, electrofuels.

FIGURE 9
Electrofuel generation



Electrofuels have yet to see market penetration due to high production costs and energy conversion losses, but they offer potential for zero-carbon drop-in fuels across transportation modes, including aviation and marine applications.

Carbon intensity of electrofuels

There are no existing fuel pathways with a calculated CI for electrofuels in a regulatory framework. However, electrofuel technologies under development are largely focused on producing carbon-neutral fuels, and no net GHG emissions over the lifecycle of the fuel. The CI of electrofuels will largely depend on the source of the electricity and carbon used to produce the fuel. Electrofuels generated from hydrogen produced through electrolysis, and renewable electricity powered direct air capture will have a CI of zero.

Feedstock availability of electrofuels

Electrofuels require consistent supplies of carbon and renewable electricity. Assuming carbon capture technology is at scale, market penetration of electrofuels will depend on reliable sources of zero-carbon electricity. As global demand for clean electricity grows in response to net-zero carbon policies, electrofuels will have to compete with other end uses of electricity in the power and industrial sectors and for the direct supply of electricity for EVs. Drop-in electrofuels require five times more electricity generation to achieve the same distance as an EV, placing additional burdens on the supply of clean electricity. Efficiency gains as electrofuel technologies are commercialized can help mitigate this differential, and electrofuels may provide utilization or storage of surplus or curtailed variable renewable energies providing stability to the electricity grid.

Air quality impacts of electrofuels

As electrofuels are currently under development, there is uncertainty about their overall lifecycle air quality impact, which includes emissions associated with renewable electricity generation and transmission, the carbon feedstock used in fuel production, and combustion of the fuel. Electrofuels created using solar energy, for instance, will need to account for the air quality impacts associated with the manufacturing of photo-voltaic cells. However, the air quality impacts occurring from the generation of renewable electricity will be small relative to the air quality impacts of fossil fuel extraction and combustion. As electrofuels are produced synthetically, there may be ways to significantly reduce combustion emissions through the fuel generation process. However, while combustion of electrofuels may provide air quality improvements over fossil-based fuels, research is nascent and work is ongoing to assess the impact of electrofuels across a variety of applications.

Technology readiness of electrofuels

There are no commercially viable electrofuels on the market. Electrofuel technologies that use microorganisms to directly use energy from electricity and produce fuels are still in the research and development phase. Demonstration projects have produced electrofuels from renewable energy sources but continue to advance technologies to improve efficiency and reduce costs. Technologies for generating and transporting consistent, pure streams of zero-carbon electricity are also required for deployment of zero-carbon electrofuels across transportation modes. Federal funding has provided initial support for in the development of these fuels, but additional support will be required to achieve commercially viable finished electrofuels.

Economic impacts of electrofuels

While electrofuels have yet to achieve commercialization, their potential for efficiency gains, GHG reductions, and air quality improvements provide a great potential for long-term market penetration given federal economic and policy support. Since 2009, the Department of Energy has provided federal funding for electrofuel research through the ARPA-E program, funding 13 active projects to create liquid transportation fuels. The Department of Energy

estimates that a mature domestic electrofuel industry has the potential to contribute billions of dollars to the US economy.

Carbon-neutral fossil fuels

Carbon-neutral fossil fuels are petroleum fuels whose GHG emissions are offset with negative emissions technologies, resulting in net-zero GHG emissions. Within this clean fuel category, the GHG emissions of petroleum fuels can be offset by technical negative emissions technologies that capture carbon during the extraction and production of the petroleum fuel (Table 2). Technical negative emissions technologies including carbon from steam generators and combined heat and power plants and carbon captured from steam methane reforming at a refinery. GHG emissions can also be offset by projects unrelated to the production of the petroleum fuel, where the fuel producer purchases verified offset credits from another party. The CI of carbon-neutral fossil fuels is then calculated by adding the life cycle GHG emissions of the negative emissions technology offset (including land use and storage emissions) to the life cycle emissions of the finished fuel.

TABLE 2
Examples of negative emissions technologies

Natural	Technical
Afforestation and reforestation Trees take up and store carbon from the atmosphere	**Carbon capture and storage** Carbon is captured during industrial processes and power generation and stored
Soil carbon sequestration Atmospheric carbon is stored in soil	**Ocean fertilization** Nutrients are added to the ocean to increase photosynthesis and reduce atmospheric carbon
Biochar Soil amendment that may enhance soil carbon sequestration	**Direct air capture** Captures carbon directly from the air where large fans push air through filters generating a stream of pure CO_2

Carbon-neutral fossil fuels require a regulatory framework in which negative emissions technologies have a verified credit value and mechanisms for assigning offset credit to specific fuels. In 2018, California added a CCS protocol to the LCFS, allowing fuels produced with carbon capture to be used for compliance in California through low carbon fuel pathways, refinery investments, innovative crude, and direct air capture. However to date, no fuels produced with carbon capture have been used in California's LCFS program.

Beginning in 2018, fuels produced with carbon capture can be used for compliance in California's Low Carbon Fuel Standard (LCFS).

Carbon-neutral fossil fuels have been controversial with advocates who do not support continued fossil fuel combustion. In addition, carbon-neutral fossil fuels combustion does not improve air quality, water quality, or reduce adverse health outcomes in communities across the US. Carbon-neutral fossil fuels also do not avoid environmental degradation from fossil fuel extraction, specifically in natural and working lands across the US.

Carbon intensity of carbon-neutral fossil fuels

The CI of carbon-neutral fossil fuels is a function of the CI of the fuel pathway and any offsetting CI reduction from carbon capture projects. Under the LCFS, the reductions associated with CCS projects are calculated on a project or a fuel pathway basis. In this fuel category, we assume that sufficient negative emissions credits are bundled to completely offset the emissions of the fossil fuel. Thus, by either purchasing credits or generating credits through on-site carbon capture, fossil-based fuels including gasoline, diesel, and jet fuel can be net-carbon neutral.

Feedstock availability of carbon-neutral fossil fuels

The feedstock for carbon-neutral fossil fuels is negative emissions technology. The availability of that feedstock will be determined by the relative value of the GHG

reduction from the negative emissions technology. To achieve net-zero emissions by 2050, the US will need hundreds of millions to more than a gigaton of negative emissions. As sectors vie to reduce emissions under varying regulatory and legislative frameworks, the negative emission reductions will go to the sector where it can receive the highest value. Therefore, a strong regulatory framework with a high credit value can work to ensure feedstock availability. However, a low-price signal for the value of captured carbon would reduce the availability of feedstock and limit the potential market penetration of carbon-neutral fossil fuels.

Air quality impacts of carbon-neutral fossil fuels

Carbon-neutral fossil fuels have air quality impacts related to the production and combustion of fuel as well as any air quality impacts related to carbon capture and sequestration. Carbon-neutral fossil fuels will have the same combustion emissions as fossil fuels, with the net air quality impact determined by the impact of the offsetting carbon capture. As the carbon capture likely occurs in a different location than fuel combustion, the health impacts of the combustion of these fuels are likely to be the same as fossil fuels, assuming similar driving patterns.

Carbon capture projects can have a beneficial impact on air quality as air pollutants are captured and stored along with carbon. They may capture criteria pollutants that would otherwise be emitted as the carbon is captured and sequestered. Carbon captured in the extraction or production of the fossil fuel may result in lower localized air pollution relative to traditional fossil fuels. Carbon that is captured off-site from the production of the fossil fuel may result in air quality improvements at the site of the carbon capture—resulting in no localized air quality benefit at the point of fossil fuel production.

Technology readiness of carbon-neutral fossil fuels

Negative emissions technology will play a critical role in achieving net-zero carbon emissions by 2050. While carbon capture opportunities at ethanol facilities are commercially viable and present opportunity in the near-term to offset the GHG emissions of fossil fuels, promising categories for carbon removal have not yet reached commercialization. Lack of large-scale carbon transport networks and distance from energy production facilities to storage location have hampered adoption. Additional research and development is needed to deploy BECCS technologies at reduced cost and scale, and regulatory frameworks are not yet fully deployed to provide the market signal required for carbon capture market penetration.

Economic implications of carbon-neutral fossil fuels

Carbon capture technologies present large domestic economic opportunity both for project-based industrial direct air capture (DAC) and carbon capture at existing ethanol and fossil fuel facilities. In previous work, we estimate that full-scale DAC deployment required for net-zero emissions in 2050 can generate at least 300,000 new jobs across the DAC supply chain. Market penetration of fuels produced with carbon capture can increase DAC demand and can provide employment in communities across the US, specifically low-income and historically disadvantaged communities located near industrial facilities.

CHAPTER 4

Policy Recommendations

The federal government plays a large role in determining the US fuel mix. Research funding, fiscal incentives, market-based policies, and GHG and air quality targets all shape the portfolio of fuel consumed across the country. Even with aggressive electrification throughout the sector, there will still be a substantial need for transportation fuel in 2030 and beyond. Transportation fuel demand can be filled with petroleum, or the federal government can take action to accelerate the deployment and market penetration of clean fuels. The question for policymakers, then, is what is the optimal portfolio of fuels in 2030, and what are the policy tools to get there?

Here we focus on three categories of federal policy levers that can be deployed by federal policymakers to develop and deploy a spectrum of clean fuels, in order to put the transportation sector on a path to net-zero emissions by 2050.

Research and development

The majority of clean fuel technologies have not yet reached commercialization, and there is a significant need for continued federal support in the research and development of advanced technology fuels. Federal funding has been critical in the development and advancement of commercial biofuels, and the government should increase funding and investment for the development of advanced fuel technologies. In the US, the ARPA-E program has been the traditional funding source for transformational fuel technology development. While it has faced funding challenges and roadblocks, ARPA-E type funding should be continued and expanded to explore high-risk fuel pathways that can transform the transportation sector and result in commercially viable products. In addition to direct funding of clean fuel technologies, the federal government should prioritize investments in training a diverse cohort of scientists and engineers through university grants and federal internships. Reinvigorating investments in science and human capital can drive innovation in breakthrough technologies.

Federal grants and incentives can drive development and commercialization of transformational fuel technologies.

Deployment and validation

The federal government can accelerate the development and deployment of clean fuels through fiscal incentives and procurement requirements. Fiscal incentives targeting fuel manufacturers can increase the supply of clean fuels by providing tax credits and loan guarantees to accelerate innovation and reduce costs related to feedstocks and processing of clean fuels. Production incentives can drive deployment of clean fuels and increase market penetration and improve transport and storage of clean fuels. Fiscal incentives directed at industry and consumers can stimulate demand for clean fuels by providing rebates and tax credits for the purchase of clean fuels.

Federal procurement policies can increase demand for clean fuels and stimulate the development of clean fuel supply chains, which can reduce costs for clean fuel storage and transportation and lead to clean fuel penetration in the private sector.

Federal procurement of clean fuels can drive down production costs and drive market penetration.

Federal fiscal incentives and procurement policies can be coupled with state and local incentives to amplify their impact. These federal polices can be technology-neutral and drive innovation across clean fuel categories or can target specific technologies or fuel types. Technology-neutral incentives and procurement

could be based on the carbon intensity of clean fuels, providing larger incentives for the lowest CI fuels. Targeted policies could provide incentives for the commercialization of a specific clean fuel or processing technology.

Deep market penetration

Deploying clean fuels in the volumes required to achieve net-zero emissions by 2050 will require a durable price signal and a robust federal policy framework. Currently, the framework for federal fuel policy is the Renewable Fuel Standard (RFS) implemented by US EPA under the authority of the Clean Air Act. The RFS is a volumetric mandate across four fuel categories—biomass-based diesel, cellulosic biofuel, advanced biofuel, and total renewable fuel—and is designed to reduce GHG emissions and expand the portfolio of renewable fuels in the US. The currently specified fuel volumes end by 2022, and EPA has discretion as to the best path to modify the RFS. The RFS has been plagued by low volumes of advanced biofuels and in December 2019, used the cellulosic biofuel waiver to reduce the volume requirements across cellulosic biofuel, advanced biofuel, and total renewable fuels.

Given the failure of the RFS to drive deployment of advanced fuels, many stakeholders are calling for significant revisions to the program. Some policymakers suggest adding additional fuel categories to include electricity from qualifying renewable fuels or "eRIN". Other advocates suggest that federal policymakers create a Clean Fuel Standard (CFS), leveraging successful design elements from existing state LCFS programs across all clean fuel categories. California and Oregon have implemented LCFS programs that will reduce the CI of their state fuel portfolios. The LCFS programs have driven investment in clean fuel production and supported ZEV penetration through electricity and hydrogen fuel pathways.

The specific design of a federal CFS will dictate the clean fuels that are developed and deployed across the US. A technology-neutral federal CFS should include all clean fuel categories and direct electrification and include all transportation modes, including aviation and marine applications, to the extent feasible. A federal CFS should also account for regional variability in fuel production and combustion, providing compliance flexibility for states and regions with additional air quality, equity, and economic considerations.

In addition to incorporating design elements that address potential disbenefits of clean fuels, a federal CFS could be coupled with additional federal, state, and local policies. Carbon pricing, through a carbon tax or cap-and-trade system, could complement a CFS and drive additional demand for the lowest carbon fuels by adding additional costs to carbon intensive fuels. Air quality policies could set additional limits on fuel combustion in regions with poor air quality, focusing on ensuring that low-income communities and communities of color see direct air quality benefits from the CFS. Economic policies can complement a federal CFS to ensure that drive domestic production of clean fuels and support the creating of high paying jobs across the clean fuel supply chain in communities across the US.

A Clean Fuel Standard can drive deep market penetration of the lowest carbon fuels.

A technology-neutral CFS can drive large-scale deployment of the lowest carbon fuels, including electricity. Under a federal CFS modeled on the LCFS programs implemented at the state level, the federal government sets annual CI targets that decline each year, requiring the increasing use of clean fuels over time in line with net-zero emissions by 2050. Fuels with CI above the target generate deficits, while fuels below the CI target generate credits. Fuel producers comply with the CFS by generating or buying credits to offset any deficits generated by their portfolio of fuels.

A CFS can also complement transportation policies that drive emissions reductions through direct electrification and efficient mobility. Achieving net-

zero emissions in 2050 will require aggressive federal action to reduce transportation demand, electrify vehicles, and develop and deploy clean fuels. A portfolio of policies can drive emissions reductions across transportation modes and amplify reductions from policies enacted at the state and local level. A CFS can also support policies driving emissions reductions in other sectors, including the energy and agricultural and waste sectors.

A portfolio of aggressive federal transportation policies is needed to achieve net-zero emissions by 2050.

Achieving net-zero emissions in the transportation sector will require aggressive federal policies across decarbonization pathways. Given future demand for transportation fuel, the US needs policies that promote development and wide-spread deployment of clean fuel, alongside electrification and efficiency measures. Clean fuel policies should focus on the comprehensive impacts—providing the largest incentives for the highest performing fuels across attributes and ensuring that deep decarbonization can be achieved across all modes of transportation.

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Rhodium Group

Statement of Principles

The transportation sector and the national economy cannot achieve net-zero emissions by 2050 without addressing transportation fuels. A broad-based coalition of interests could help create demand for and support a national clean fuels policy, consistent with the following principles:

1. Transportation fuels must be decarbonized in sufficient time to achieve national net-zero emissions in the transportation sector not later than 2050.

2. Fuels decarbonization policy should be coordinated and not conflict with other greenhouse gas and pollution reduction policies and goals. Such policies should work together in an efficient and synergistic way.

3. Any new clean fuels policy must be integrated with complementary emissions control and transportation policies to reduce air pollution in and barriers to clean transportation for low-income and overburdened communities. And it must not perpetuate historical injustices in the form of pollution and public health impacts associated with the production, distribution, and use of fossil fuels.

4. A life-cycle emissions performance-based approach that is technology and feedstock neutral is essential to achieve fuels decarbonization and promote innovation and investment across all potential clean fuel types including electricity, hydrogen, biofuels, and other low-carbon fuels.

5. Achieving the decarbonization goal and maximizing consumers' benefits can be most effectively accomplished by steadily growing market opportunities for low-carbon fuels with transparency, scale, and fair competition. Any such markets or programs must include safeguards and incentives across sectors to protect and enhance environmental integrity, including biodiversity, and to promote job creation and equitable and sustainable economic growth.

6. Any legislative or regulatory program should start not later than 2023 and provide clear long-term market signals for investors, cross-sectoral market participants, technology innovators, and feedstock suppliers. Such policy or program should be implemented efficiently and transparently and directed with unambiguous language and intent.

7. States or regions may implement clean fuels programs that are designed to steadily decarbonize transportation fuels. States or regions may increase the stringency of their program's decarbonization requirements if they have the technical capacity to manage the program.

8. The federal government and the states can and should make a constructive and sustained effort to a) ensure the best possible science is being used to support the value of fuels decarbonization, including with respect to life cycle analysis and applicable verification and reporting, and b) expand the research, development, and deployment of low, zero, and negative carbon fuels technologies and practices, including demonstration projects and technical assistance.

The Honorable Frank Pallone
Chairman, Energy and Commerce Committee
United States House of Representatives
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Washington, DC 20515

The Honorable Cathy McMorris Rodgers
Ranking Member, Energy and Commerce Committee
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2322 Rayburn House Office Building
Washington, DC 20515

The Honorable Thomas Carper
Chairman
Environment and Public Works Committee
United States Senate
410 Dirksen Senate Office Building
Washington, D.C. 20510

The Honorable Shelley Moore Capito
Ranking Member
Environment and Public Works Committee
United States Senate
456 Dirksen Senate Office Building
Washington, D.C. 20510

Chairman Pallone, Ranking Member McMorris Rodgers, Chairman Carper, and Ranking Member Capito:

The undersigned organizations are writing to urge the Committee to begin the legislative process to address the issue of decarbonizing the transportation fuel sector in support of a national goal of net-zero greenhouse gas emissions economy-wide not later than 2050. Without immediate action in the 117th Congress, that goal is very likely unattainable.

A strong national clean fuels policy that sends clear long-term and durable signals will encourage rapidly growing investment in the technologies needed to simultaneously reduce criteria and carbon pollution in all communities across America. Designed properly, it will spur innovation, create jobs, and ensure equitable and sustainable economic growth, as well as smooth the transition to a cleaner and more just zero-carbon future.

The organizations listed represent a wide but not exclusive list of stakeholders deeply invested in reducing emissions from transportation fuels, including automakers, farmers, environmental groups, utilities, science-based organizations, renewable fuel producers, technology companies, electric vehicle charging companies, truck and bus manufacturers, emissions controls makers, non-profit clean energy organizations, and more.

We would welcome the opportunity to participate in an open dialogue with the Committee as you consider or begin this important work. Our organizations look forward to providing additional information and engaging with you as the process moves forward. Further, we encourage you to consult with and hear from all stakeholders, in particular frontline and disadvantaged communities and communities of color, who have a stake in setting the country on a clean transportation path.

Sincerely,

Advanced Biofuels Association (ABFA)
Advanced Engine Systems Institute (AESI)
Alliance for Automotive Innovation
American Coalition for Ethanol
Amply Power
Biotechnology Innovation Organization (BIO)
BYD Motors
ChargePoint
ClearFlame
Coalition for Renewable Natural Gas (RNG Coalition)
Cummins
Dominion Energy
DTE Energy
EVgo
Great Plains Institute
Low Carbon Fuels Coalition
Manufacturers of Emission Controls Association (MECA)
National Corn-to-Ethanol Research Center (NCERC)
National Corn Growers Association (NCGA)
Neste
Renewable Fuels Association
South Dakota Corn Growers Association
World Energy


Advanced
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Association


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ALLIANCE
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american coalition for
ethanol


AMPLY
POWER


Bio
Biotechnology
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Organization


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THE COALITION FOR
RENEWABLE
NATURAL GAS


Cummins


Dominion
Energy
Actions Speak Louder


DTE


EVgo
FAST CHARGING


GREAT PLAINS
INSTITUTE
Better Energy.
Better World.


LOW CARBON
FUELS COALITION


MECA


NCERC at SIUE
Advancing Biorenewables Research


NATIONAL
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40
RFA
RENEWABLE FUELS
ASSOCIATION


SOUTH DAKOTA
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world energy



A Low Carbon Fuel Standard: In Brief

Kelsi Bracmort
Specialist in Natural Resources and Energy Policy

July 7, 2021

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R46835

CRS REPORT
Prepared for Members and
Committees of Congress

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A Low Carbon Fuel Standard: In Brief

SUMMARY

R46835

July 7, 2021

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Specialist in Natural Resources and Energy Policy
kbracmort@crs.loc.gov

For a copy of the full report, please call 7-5700 or visit www.crs.gov.

As part of the congressional deliberations on addressing climate change, Congress may consider policy options for reducing greenhouse gas (GHG) emissions from the transportation sector. One of the leading contributors to the U.S. GHG emission profile in 2019 was carbon dioxide (CO_2) emitted from fossil fuel combustion by the transportation sector (e.g., gasoline and diesel consumption in automobiles, freight trucks, and aircraft). While Congress has acted to impact transportation sector GHG emissions (e.g., the Renewable Fuel Standard or RFS), some Members of Congress are evaluating taking additional action.

One policy option Congress may examine is a low carbon fuel standard (LCFS). An LCFS is a policy that requires transportation fuels to meet a certain energy-related GHG target (e.g., a specific carbon intensity) within a specified jurisdiction and timeframe. Some states have established an LCFS (e.g., California), and some states and regions are considering adopting an LCFS (e.g., Colorado). Generally, an LCFS is intended to be both fuel-neutral and technology-neutral. Eligible fuels for an LCFS could be required to meet certain requirements, such as a lifecycle assessment (LCA), which typically quantifies the environmental impact of a fuel from its extraction or feedstock production to its end use. Challenges to LCFS implementation include the determination of an appropriate energy-related GHG target, development of a robust LCA, and construction of a transparent compliance system.

Some in Congress are considering and have previously considered an LCFS. For instance, in the 117th Congress the Sustainable Aviation Fuel Act would establish a Low Carbon Aviation Fuel Standard that sets a carbon intensity benchmark for aviation fuel (S. 1608). Legislation that would have created an LCFS for motor vehicle fuel, non-road vehicle fuel, and aircraft fuel was introduced and at least one congressional hearing was held in the late 2000s. Some in Congress have opposed an LCFS, citing concerns about economic effects, including the potential for job losses, limited affordable lower carbon fuel options, and increasing fuel prices.

Some in Congress recommend that the existing RFS transition to an LCFS. The RFS requires renewable fuel be blended into the nation's transportation fuel supply. How a transition would happen is unclear given that the RFS is structured differently from existing state LCFS policies. For example, the RFS is a volume mandate that requires the use of renewable fuel volumes as specified in statute; the existing state and proposed LCFS programs are structured as a carbon intensity mandate that requires eligible transportation fuels to meet a certain carbon emission target. Further, the RFS only allows fuels made from renewable biomass; existing state LCFS programs have allowed a wide array of clean and renewable fuels. The statutory renewable fuel volume amounts for the RFS expire in 2022 with the U.S. Environmental Protection Agency (EPA) Administrator determining the volume amounts starting in 2023.

Congress would have the option to design a national LCFS according to congressional priorities. Discussions that Congress may have about a potential LCFS may or may not be influenced by state actions. Additionally, Congress would have many items to consider if it chooses to authorize a national LCFS. These items include policy certainty, a mechanism for the LCFS program to adapt to unforeseen circumstances, regional needs and ability, land use change, consumer choice, distributional effects, and equity, among others.

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Introduction

Congress continues to debate whether and how to address the greenhouse gas (GHG) impacts of transportation fuels.[1] The transportation sector was the leading contributor to U.S. GHG emissions in 2019—based on the most recent data available from the U.S. Environmental Protection Agency (EPA).[2] Passenger cars, light-duty trucks, and medium- and heavy-duty trucks constitute the bulk of transportation GHG emissions for 2019 (approximately 82%).[3] The majority of fuels used to operate those vehicles originate from fossil fuels (e.g., gasoline and diesel from crude oil).[4] The production and use of transportation fuels results in GHGs, which are typically emitted into the atmosphere or sometimes—though less frequently—sequestered.[5]

In 2005, Congress established a program—the Renewable Fuel Standard (RFS)—that was intended to, among other things, reduce the GHG emission impact of the U.S. transportation fuels portfolio.[6] The RFS mandates that U.S. transportation fuels contain a minimum volume of biofuel;[7] statutory annual volume requirements increased over time, but cease in 2022, with the EPA Administrator determining the volume amounts after 2022 with certain limitations.[8] There is

[1] For example, see the Build a Cleaner and More Resilient Transportation Sector section of the U.S. Congress, House Select Committee on Climate Crisis, *Solving the Climate Crisis—The Congressional Action Plan for a Clean Energy Economy*, 116th Cong., June 2020.

[2] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019*, EPA 430-R-21-005, April 14, 2021. From 2017 through 2019, the transportation sector has been the largest contributor of U.S. GHG emissions, followed closely by the electric power sector. For more information on greenhouse gases, see U.S. Environmental Protection Agency, *Greenhouse Gases—EPA's Report on the Environment*, https://www.epa.gov/report-environment/greenhouse-gases.

[3] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2019*, Table 2-13: Transportation-Related Greenhouse Gas Emissions, April 14, 2021.

[4] For more information, see U.S. Energy Information Administration, *Oil and Petroleum Products Explained*, March 23, 2021. Petroleum—a type of fossil fuel—accounted for approximately 90% of the energy consumed in the transportation sector in the United States in 2020. U.S. Energy Information Administration, *Monthly Energy Review*, Table 2.5 "Transportation Sector Energy Consumption," June 2021. There are three primary petroleum transportation products: motor gasoline, diesel, and jet fuel. Motor gasoline accounted for approximately 65% of petroleum consumed in 2020; distillate fuel oil (i.e., diesel) accounted for approximately 24%; jet fuel accounted for approximately 9%. U.S. Energy Information Administration, *Monthly Energy Review*, Table 3.7c, "Petroleum Consumption: Transportation and Electric Power Sectors," June 2021.

[5] A greenhouse gas is any gas that absorbs infrared radiation in the atmosphere (e.g., carbon dioxide, methane, nitrous oxide, ozone, hydrofluorocarbons). An emission is the release of a substance (usually a gas when referring to the subject of climate change) into the atmosphere. Sequestration can occur in two forms—biologic or geologic. Biologic carbon sequestration is the process by which trees and plants absorb carbon dioxide, release the oxygen, and store the carbon. Geologic sequestration involves injecting carbon dioxide deep underground. U.S. Environmental Protection Agency, *Glossary of Climate Change Terms*, September 29, 2016. For more information on carbon capture and sequestration, see CRS In Focus IF11501, *Carbon Capture Versus Direct Air Capture*, by Ashley J. Lawson and CRS In Focus IF11345, *Carbon Sequestration Legislation in the 116th Congress*, by Angela C. Jones.

[6] P.L. 109-58.

[7] For more information on the RFS, see CRS Report R43325, *The Renewable Fuel Standard (RFS): An Overview*, by Kelsi Bracmort.

[8] There is one exception. The statutory annual volume amounts for biomass-based diesel were prescribed only through 2012 (42 U.S.C. §7545(o)(2)(B)(i)(IV)). The EPA Administrator has other statutory authorities including the authority to waive the RFS requirements under certain conditions and the authority to "reset" the RFS given certain conditions. For more information on RFS waiver authority and a RFS reset, see CRS Report R44045, *The Renewable Fuel Standard (RFS): Waiver Authority and Modification of Volumes*, by Kelsi Bracmort.

interest amongst some Members of Congress about how EPA will administer the RFS post-2022 and if legislative action would be required to change how EPA administers the RFS post-2022.[9]

Some in Congress have discussed the option of implementing a national low carbon fuel standard (LCFS) to further address the transportation sector's contribution to GHG emissions, as well as to possibly transition the RFS away from its current biofuel volume requirements.[10] In short, an LCFS is a policy that requires transportation fuels to meet a certain energy-related GHG target. An LCFS is one of many options that could potentially curb GHGs from the transportation sector. Other options include vehicle GHG emission standards, more efficient engines and/or transportation modes, and less travel. Congress could consider these options—and their potential impacts—singularly or in tandem.[11]

A national LCFS presents both opportunities and challenges. Potential opportunities include a transportation fuel policy with an explicit directive to address carbon emissions and therefore climate change, and the possibility to spur development of emerging alternative transportation fuels that, while providing a range of environmental benefits (as well as some potential drawbacks), may initially be more cost-prohibitive to produce. Potential challenges include regulatory flexibility, long-term policy certainty, and technical expertise.

This report provides a brief overview of an LCFS, congressional interest in an LCFS, the connection between the RFS and an LCFS, and considerations for policymakers. The report also briefly discusses the California LCFS and some of the proposed regional programs. This report is not a comprehensive analysis of all components related to an LCFS.

A Low Carbon Fuel Standard

This section describes the key features of an LCFS as a potential starting point for a discussion. It discusses an LCFS as structured under some existing state policies and based on a review of selected sources which included federal documents, scientific literature, stakeholder perspectives, and more.[12] Although there is no federal LCFS, several states have enacted or proposed LCFS policies applied to transportation fuels.[13] A potential national LCFS may or may not be tethered to one of the aforementioned sources (e.g., existing state policy or stakeholder recommendations). Should Congress choose to enact an LCFS, Congress may design a program that satisfies congressional priorities. Should Congress want to construct an LCFS, Congress has multiple options to consider, including the ultimate policy objective, the policy metrics, and more.

An LCFS requires transportation fuels to meet a certain target—based on the average GHG emissions of the fuel—within a specified jurisdiction and timeframe.[14] In general, this target

[9] Marc Heller, "Grassley Says RFS Debate Could Explode Come 2022," *E&E Daily*, June 17, 2020; Jonathan H. Harsch, "Battle Brewing over Ethanol Program Post 2022," *Agri-Pulse*, March 1, 2017.

[10] See e.g., U.S. Congress, Senate, *The Case for Climate Action: Building a Clean Economy for the American People*, prepared by Senate Democrats' Special Committee on the Climate Crisis, 116th Cong., August 25, 2020, p. 57; and U.S. Congress, House Select Committee on Climate Crisis, *Solving the Climate Crisis: The Congressional Action Plan for a Clean Energy Economy and a Healthy, Resilient, and Just America*, 116th Cong., June 2020, p. 101.

[11] For more information on vehicle GHG standards, see CRS In Focus IF10871, *Vehicle Fuel Economy and Greenhouse Gas Standards*, by Richard K. Lattanzio, Linda Tsang, and Bill Canis.

[12] An exhaustive review of LCFS literature and perspectives is beyond the scope of this report.

[13] States with an existing LFS include California, Oregon, and Washington. States that have considered an LCFS include Colorado, New Mexico, and New York.

[14] Another name for an LCFS is a clean fuel standard (CFS).

becomes more stringent over time. An LCFS may be designed to address GHG emissions from one or multiple transportation fuel types (e.g., gasoline, aviation fuel, etc.). Each fuel receives a score based on its GHG emissions. Typically, a credit system is used to allow flexibility to show program compliance. The regulated parties—those that must demonstrate compliance—usually include transportation fuel producers, importers, and refiners.

The overall goal of existing nonfederal LCFS policy is to reduce the carbon intensity (CI) of transportation fuels (see text box). Existing nonfederal LCFS policy is intended to be fuel-neutral and technology-neutral.[15] Based on existing programs, an LCFS sets an annual CI target and then allows the regulated parties and/or the market to determine the best method to achieve the target.[16]

Under existing programs, compliance with the annual CI target is measured using a credit system. Credit system design can vary. In general, a regulated party obtains enough credits to demonstrate compliance at the end of the compliance period. A credit is generated for those transportation fuels with a CI score that is below the CI target. A deficit is generated for those transportation fuels with a CI score above the CI target. Typically, surplus credits can be traded or saved for future compliance. Based on existing programs, regulated parties ordinarily have two options to show LCFS compliance: (1) acquire eligible fuels with attached credits, and (2) acquire credits. Regulated parties typically will either produce eligible fuel themselves or purchase it from others. Regulated parties typically will purchase credits from producers who are selling their excess credits, or they may use credits remaining from their previous compliance periods, if such flexibilities are allowed.

An LCFS has certain scientific and technical features. First, fuels are usually rated based on a lifecycle assessment (LCA) of their *pathway*. A pathway is how a fuel came to be—its source, its method of conversion to fuel, and its type.[17] The LCA quantifies, among other effects, the GHG emissions of a fuel throughout its entire lifecycle (e.g., for fossil fuels this may include from extraction through combustion, commonly referred to as "well to wheels)."[18] Under such an analysis, the same transportation fuel brought to market by different producers may have vastly different lifecycle emissions profiles. For example, different gasoline supplies can have different emissions profiles based upon their production pathways (e.g., mined and refined bitumen versus conventionally extracted and refined light, sweet crude oil). Second, there is usually a program

[15] Sonia Yeh et al., *National Low Carbon Fuel Standard: Technical Analysis Report*, Institute of Transportation Studies, University of California, Davis, Research Report UCD-ITS-RR-12-11, July 19, 2012. This is in contrast to the federal RFS, which mandates the use of fuels produced from renewable biomass.

[16] An LCFS may apply specific CI targets to different fuel types (i.e., gasoline, diesel, aviation fuel) and their substitutes (e.g., ethanol, renewable diesel, sustainable aviation fuel).

[17] Fuel sources include crude oil, natural gas, hydrogen, biomass, and more. Fuel conversion methods include distillation, compression, liquefaction, reformation, gasification, electrolysis, dry mill, and more. Fuel types include gasoline, diesel, jet fuel, compressed natural gas, liquefied natural gas, hydrogen, electricity, palm oil biodiesel, corn starch ethanol, and more.

[18] One of the more controversial aspects of an LCA for transportation fuels is emissions due to direct and indirect land use change. There is debate about which fuels should undergo land use change examination, whether to account for land use change emissions, and how to estimate such emissions. For this reason and others (e.g., the model used for the LCA, the assumptions made, etc.), it is possible for there to be disagreement on the estimated GHG impact of a transportation fuel. Further discussion about LCA is beyond the scope of this report. For more information on the variability and uncertainty associated with modeling the GHG impact, or carbon intensity, of transportation fuels see Sonia Yeh et al., "A Review of Low Carbon Fuel Policies: Principles, Program Status and Future Directions," *Energy Policy*, vol. 97 (2016). For more information on LCA for electric vehicles, see CRS Report R46420, *Environmental Effects of Battery Electric and Internal Combustion Engine Vehicles*, by Richard K. Lattanzio and Corrie E. Clark.

metric that signifies the carbon intensity of the eligible fuels.[19] Third, there is usually a baseline or benchmark to which the eligible fuels are compared. Fourth, there is usually a pricing mechanism by which credits are assigned a value relative to the eligible fuel.

The scientific and technical aspects of an LCFS may involve a range of implementation challenges. Challenges include the robustness of the LCA (e.g., which data are included in the assessment and how the data are collected and updated), construction of a transparent compliance system, and determination of an appropriate GHG reduction target and a corresponding pricing mechanism to provide for the specified policy goals. Also, policymakers may want to consider regional demands and resources when designing an LCFS (e.g., feedstock availability in certain regions of the country).

Carbon Intensity (CI)

Carbon intensity can have various interpretations and means of measurement in different contexts. In general, carbon intensity measures how much GHG, or in particular carbon dioxide (CO_2), is emitted relative to some metric (e.g., electricity produced, fuel consumed, or dollars generated). For example, the U.S. Energy Information Administration (EIA) defines CI as the "amount of carbon by weight emitted per unit of energy consumed."[20] EPA defines CI as the "relative amount of carbon emitted per unit of energy or fuels consumed."[21] The U.S. Department of Energy (DOE) has referred to CI as the "measure of CO_2 produced per dollar of GDP."[22]

There can be a range of CI scores for a single fuel type depending on the fuel pathway, which may take into account the feedstock, feedstock transportation to the conversion facility, the fuel produced, transportation of the fuel to its end-use location, and more.[23] CI may only account for carbon dioxide or it may account for multiple GHGs (with other GHGs weighted based on their warming potential relative to CO_2). Carbon intensity may only reflect one part of the activity (e.g., biomass growth and harvest), or it might reflect the entire activity cycle (e.g., biomass growth and harvest, biomass conversion to a liquid fuel, delivery of liquid fuel to pump).

For an LCFS, CI is typically defined as the amount of carbon by weight emitted per unit of energy consumed for a given transportation fuel. The California Air Resources Board (CARB) reports that a fuel pathway CI "consists of the sum of the greenhouse gases emitted throughout the production and use life cycle of the fuel, expressed on a per-unit-of-fuel-energy basis."[24] CARB expresses CI in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ).[25]

While there are public laws that include the term "carbon intensity" (see, for example, the Energy Policy Act of 2005, P.L. 109-58), carbon intensity is not defined in federal statute. Members introduced bills in the 116th Congress and the 117th Congress that would have defined carbon intensity. For instance, H.R. 8769 (116th Congress) and S. 1608 (117th Congress) would have defined carbon intensity for aviation fuel as the quantity of lifecycle GHG emissions per unit of fuel energy (similar to the CA-LCFS).

[19] Existing state programs use gCO_2e/MJ (see text box).

[20] U.S. Energy Information Administration, *Glossary*, July 6, 2021.

[21] U.S. Environmental Protection Agency, *Terminology Services*, July 6, 2021, https://iaspub.epa.gov/sor_internet/registry/termreg/searchandretrieve/termsandacronyms/search.do?search=&term=carbon%20intensity&matchCriteria=Contains&checkedAcronym=true&checkedTerm=true&hasDefinitions=false.

[22] U.S. Department of Energy, *Interactive: Energy Intensity and Carbon Intensity by the Numbers*, February 19, 2016.

[23] For an example of carbon intensity scores for various fuel types, see California Air Resources Board, *LCFS Pathway Certified Carbon Intensities*, July 6, 2021.

[24] California Environmental Protection Agency, Air Resources Board, *Staff Report: Calculating Life Cycle Carbon Intensity Values of Transportation Fuels in California*, March 2015.

[25] California Code of Regulations, 17 CCR §95481(a)(26).

Congressional Interest in a Low Carbon Fuel Standard

For over a decade, some Members of Congress have expressed an interest in a national LCFS.[26] In 2009, a Member remarked "Establishing a low carbon fuel standard is one method that can be used to reduce greenhouse gas emissions and to encourage the development of less carbon-intense fuels."[27] More recently, some Members have again expressed support for an LCFS. For example, in 2020, a group of Members stated that an LCFS may "be an effective policy to reduce the carbon intensity of the fuel supply."[28] Others have called for the Renewable Fuel Standard (RFS) to transition to an LCFS.[29] In 2018, one Member stated "This performance-based standard [the California LCFS] clearly has greater climate benefits, but it seems to me that its flexibility is also better for the advanced biofuels industry."[30] In 2021, the Sustainable Aviation Fuel Act (S. 1608) was introduced; the bill would establish a Low Carbon Aviation Fuel Standard that sets a carbon intensity benchmark for aviation fuel.

Alternatively, some Members of Congress have opposed an LCFS. For instance, in 2013, some in Congress expressed that "affordable and reliable lower carbon fuel options do not exist," and that a nationwide LCFS set to reduce the carbon intensity of transportation fuels by 10 percent over 10 years could "increase gasoline and diesel prices by as much as 170 percent" and "destroy up to 4.5 million jobs."[31]

State and Regional Low Carbon Fuel Standards

Congress may want to consider low carbon transportation fuel action taken by some states. Three states have established an LCFS: California, Oregon, and Washington, with the latter two being recently established.[32] Some states have considered an LCFS, including Colorado, Minnesota, New Mexico, and New York.[33] Additionally, some states are considering the creation of a regional

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[26] In the 110th Congress, Members introduced several bills, that would have established an LCFS. For more information on the bills introduced during the 110th Congress, see archived CRS Report R40078, *A Low Carbon Fuel Standard: State and Federal Legislation and Regulations*, by Brent D. Yacobucci (out of print; available from the author). Also, one bill was introduced during the 111th Congress (S. 1095).

[27] U.S. Congress, House Committee on Agriculture, *Hearing to Review Low Carbon Fuel Standard Proposals*, 111th Cong., 1st sess., May 21, 2009.

[28] U.S. Congress, Senate, *The Case for Climate Action: Building a Clean Economy for the American People*, prepared by Senate Democrats' Special Committee on the Climate Crisis, 116th Cong., August 25, 2020, p. 57.

[29] U.S. Congress, House Select Committee on Climate Crisis, *Solving the Climate Crisis: The Congressional Action Plan for a Clean Energy Economy and a Healthy, Resilient, and Just America*, 116th Cong., June 2020, p. 101. For more information on the RFS, see CRS Report R43325, *The Renewable Fuel Standard (RFS): An Overview*, by Kelsi Bracmort.

[30] U.S. Congress, House Committee on Energy and Commerce, Subcommittee on Environment, *Advanced Biofuels Under the Renewable Fuel Standard: Current Status and Future Prospects*, 115th Cong., 2nd sess., June 22, 2018.

[31] *Americans Can't Afford Democrats' National Energy Tax*, prepared by Senate Republican Policy Committee, June 25, 2013.

[32] Governor Arnold Schwarzenegger, *Executive Order S-01-07*, Office of the Governor of California, Sacramento, CA, January 18, 2007; Oregon House Bill 2186 (2009); Oregon Senate Bill 324 (2016); Oregon Governor Kate Brown, *Carbon Policy Executive Order N. 20-04*, March 10, 2020; State of Washington, *House Bill 1091* – 2021-22, May 17, 2021.

[33] Colorado Energy Office, *Low Carbon Fuel Standard Feasibility Study Final Report*, September 2020; State of Colorado, *Colorado Greenhouse Gas Pollution Reduction Roadmap*, January 14, 2021; Minnesota Department of

LCFS (e.g., the Midwestern Clean Fuels Policy Initiative). This section provides some key aspects for the California LCFS (CA-LCFS) and some of the proposed regional LCFS programs.[34] Some foreign countries and regions also have implemented or proposed LCFSs; these foreign programs are not reviewed in this report.[35]

California Low Carbon Fuel Standard

- **Program Goal:** To reduce the carbon intensity of California's transportation fuels by at least 20% by 2030.[36]
- **Base year:** 2010.[37]
- **Applicable Fuels:** Any transportation fuel that is sold, supplied, or offered for sale in California.[38]
- **Program Measurement:** A carbon intensity (CI) benchmark.[39] The CI benchmark is reduced over time (i.e., the benchmark becomes more stringent over time).[40]
- **Compliance System:** Credit; credits are expressed in metric tons of CO_2e.[41]
- **Credit Price:** The average credit price was $199/credit for calendar year 2020, $192/credit for 2019, $160/credit for 2018, $89/credit for 2017, and $101/credit for 2016 as set by the market.[42]
- **Administering Agency:** The California Air Resources Board (CARB).

Agriculture, *Report in Fulfillment of Executive Order 19-35 Establishing the Governor's Council on Biofuels*, November 2, 2020; New Mexico Legislature, *SB 11 Clean Fuel Standard Act*, January 19, 2021; New York State Assembly Bill A5262A §2 (§19-0329(1)).

[34] Others have reviewed the various LCFS approaches. For more information, see Sonia Yeh et al., "A review of low carbon fuel policies: Principles, program status and future directions," *Energy Policy*, vol. 97 (October 2016) and Jacob Lipson, *Clean Fuels Program Comparison Chart: California, Oregon, and Proposed Washington Programs*, Washington State Legislature, House Environment & Energy Committee, February 11, 2019.

[35] For example, the Canadian province British Columbia has a low carbon fuel standard.

[36] For more information, see California Air Resources Board, "CARB Amends Low Carbon Fuel Standard for Wider Impact," press release, September 27, 2018.

[37] California Code of Regulations, 17 CCR §95484. "Annual Carbon Intensity Benchmarks."

[38] California Code of Regulations, 17 CCR §95482 "Fuels Subject to Regulation."

[39] CI is defined as the quantity of life cycle greenhouse gas (GHG) emissions, per unit of fuel energy, expressed in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ). California Code of Regulations, 17 CCR §95481(a)(26).

[40] California Code of Regulations, 17 CCR §95484. "Annual Carbon Intensity Benchmarks." For example, the average CI for gasoline and fuels used as a substitute for gasoline is set at 95.61 gCO_2e/MJ for 2011, 90.74 gCO_2e/MJ for 2021, and 79.55 for 2030. The CA-LCFS CI benchmarks for 2010 through 2030 are provided in tables for gasoline, diesel, and fuels used as a substitute for gasoline or diesel, as well as fuels used as a substitute for conventional jet fuel.

[41] California Code of Regulations, 17 CCR §95485, "Demonstrating Compliance."; California Code of Regulations, 17 CCR §95481, "Definitions and Acronyms."

[42] California Air Resources Board, *Monthly LCFS Credit Transfer Activity Report for December 2020*, January 12, 2021; California Air Resources Board, Monthly LCFS Credit Transfer Activity Report for December 2019, January 14, 2020 https://ww3.arb.ca.gov/fuels/lcfs/credit/July 2020 - Monthly Credit Transfer Activity.pdf; California Air Resources Board, *Monthly LCFS Credit Transfer Activity Report for December 2018*, January 8, 2019. For credit prices from January 2014 to the present, see California Air Resources Board, *LCFS Credit Transfer Activity Reports*.

Program performance:[43] In a 2019 press release,[44] CARB reported that "[from 2011 to 2018] almost 3.3 billion gallons of petroleum diesel have been displaced by clean, low-carbon alternatives," that "fuel producers are in 100 percent compliance with the LCFS," that "[Since 2011] … the program has generated credits representing a total reduction of 47.1 million metric tons of climate-changing gases"[45] and that "greenhouse gas reductions under this program have been occurring ahead of schedule."

Regions with a Proposed Low Carbon Fuel Standard[46]

Regional LCFS programs have been proposed by some entities.[47] The proposed regional programs include multiple states, and at least one proposed program included a region within one state.[48] The key difference between a regional LCFS and a state LCFS is the geographic boundary for the policy. The expansion of the program boundaries across state lines could be viewed as an opportunity for some (e.g., collaboration amongst various state agencies to reach transportation and climate goals) and a challenge for others (e.g., fuel providers may have to modify their business practices to satisfy the LCFS requirements for one region of their market). Additionally, regional programs may be designed to suit the needs and activities of that region. It is not clear whether multiple regional programs—assuming they are adopted—would affect what could be done at a national level (i.e., a national LCFS). Provided below is a brief overview for two proposed regional programs, one for the Northeast region and one for the Midwest region.

Massachusetts Clean Energy and Climate Plan / Transportation and Climate Initiative:

- Massachusetts reports it will "pursue the development and implementation of a regional Low Carbon Fuel Standard (LCFS) designed to substantially reduce the carbon intensity of transportation fuels by 2030 through a market-based crediting program that supports deployment of low carbon substitutes for petroleum-based

[43] There are other analysis of CA-LCFS program performance. For instance, see Julie Witcover, *Status Review of California's Low Carbon Fuel Standard, 2011–2018 Q1 September 2018 Issue* , UC Davis Institute of Transportation Studies, September 24, 2018 and Julie Witcover and Colin Murphy, *Status Review of California's Low Carbon Fuel Standard, Draft*, UC Davis Policy Institute for Energy, Environment, and the Economy, July 6, 2019.

[44] California Air Resources Board, "Cleaner fuels have now replaced more than 3 billion gallons of diesel fuel under the Low Carbon Fuel Standard," press release, May 16, 2019.

[45] EPA has a GHG equivalencies calculator that converts both energy data and emissions data into concrete everyday examples for the public to better understand what emission reduction looks like. EPA reports that 1 metric ton of CO_2e is equivalent to CO_2 emissions from 113 gallons of gasoline consumed. U.S. Environmental Protection Agency, *Greenhouse Gas Equivalencies Calculator*, March 2021, https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator. It is not clear how CARB defines "climate-changing gases." However, if one were to presume that "climate-changing gases" equates to CO_2e, then the EPA GHG equivalency calculator estimates that 47.1 million metric tons of CO_2e is equivalent to CO_2 emissions from 5.3 billion gallons of gasoline consumed.

[46] This section does not provide all of the actions pertaining to a potential LCFS that may occur at a regional level.

[47] Regional LCFS discussions have occurred since at least 2008. For example, see *Northeast and Mid-Atlantic Low Carbon Fuel Standard Memorandum of Understanding*, December 30, 2009, and Northeast States Center for a Clean Air Future, *Introducing a Low Carbon Fuel Standard in the Northeast Technical and Policy Considerations*, July 2009.

[48] The Puget Sound Clean Air Agency had considered an LCFS for the Puget Sound area, which encompasses four counties in the State of Washington and the city of Seattle. In April 2020, the Agency announced it was suspending any action on the Agency's draft Clean Fuel Standard. For more information, see Puget Sound Clean Air Agency, *Clean Fuel Standard: Proposed Draft Rule Background Technical Analysis*, October 2019 and TJ Martinell, "Air agency drops regional fuel standard proposal," *TheLens.News*, April 6, 2020https://pscleanair.gov/528/Clean-Fuel-Standard.

liquid transportation fuels" following the implementation of the Transportation and Climate Initiative Program (TCI-P).[49] Massachusetts also reports it will "work with its neighbors to develop and implement a regional LCFS no later than 2026."[50]

Midwestern Clean Fuels Policy Initiative:

- The Midwestern Clean Fuels Policy Initiative "aims to create a market specifically for regional clean fuel producers that simultaneously delivers environmental and economic benefits."[51] The Initiative highlights several features for a potential clean fuels policy that it thinks should receive consideration, including a fair lifecycle assessment, point of regulation, a consistent approach for all clean fuels, and fueling infrastructure.[52] The Initiative reports that developing a clean fuels policy is complicated, and provides three areas where additional work is needed: farm-level carbon accounting, biofuel credit value distribution, and electricity credit distribution.

The RFS and a National LCFS

The RFS and an LCFS both address the environmental impact of transportation fuels. Some have argued that a national LCFS could replace or complement the RFS, particularly in light of the fact that, starting in 2023, the EPA Administrator will determine the annual volume requirements.[53] If

[49] Massachusetts reports it is leading the implementation of the TCI-P. The TCI-P is a multijurisdictional cap-and-invest program. The Commonwealth of Massachusetts, *Interim Clean Energy and Climate Plan for 2030*, December 30, 2020. For more information on the TCI-P, see Transportation and Climate Initiative of the Northeast and Mid-Atlantic States, *Transportation and Climate Initiative Program Memorandum of Understanding*, December 21, 2020. The Transportation and Climate Initiative (TCI) is a regional collaboration of 12 Northeast and Mid-Atlantic states and the District of Columbia that seeks to improve transportation, develop the clean energy economy and reduce carbon emissions from the transportation sector. For more information, see *The Transportation and Climate Initiative: An Agenda for Progress Declaration of Intent*, 2010, which states "The TCI will build upon ongoing federal, state and regional collaborations, including the Regional Greenhouse Gas Initiative and the recently announced initiative to develop a framework for a Low Carbon Fuel Standard."

[50] The Commonwealth of Massachusetts, *Interim Clean Energy and Climate Plan for 2030*, December 30, 2020. It is not clear how many members of the TCI may join a regional LCFS.

[51] Great Plains Institute, *A Clean Fuels Policy for the Midwest: A White Paper from the Midwestern Clean Fuels Policy Initiative*, January 7, 2020. The Midwestern Clean Fuels Initiative reports it is a broad coalition of fuels producers and marketers, nonprofit and research organizations, scientists and engineers, and agriculture and industry stakeholders.

[52] Ibid. The initiative uses the term "clean fuels policy" instead of "low carbon fuel standard." The initiative reports that "A clean fuels policy, also known in some jurisdictions as a low carbon fuel standard or clean fuel standard, is a performance-based incentive program that supports the commercial deployment of fuels with lower lifecycle carbon intensity. A clean fuels policy evaluates all fuels used in the relevant jurisdiction based on lifecycle carbon accounting and assigns each fuel production method a unique carbon intensity (CI) score that is the complete well-to-wheels carbon equivalent emissions normalized for the energy content of the fuel."

[53] Stakeholders and others have studied and/or commented on the potential impacts of layering an LCFS on top of a RFS or replacing the RFS with an LCFS. For example, see Environmental Protection Network, *Resetting the Course of EPA: Reducing Air Emissions from Mobile Sources*, August 2020; U.S. Congress, House Committee on Energy and Commerce, Subcommittee on Environment, *Advanced Biofuels Under the Renewable Fuel Standard: Current Status and Future Prospects*, 115th Cong., June 22, 2018; U.S. Congress, House Committee on Agriculture, *Hearing to Review Low Carbon Fuel Standard Proposals*, 111th Cong., May 21, 2009; Haixiao Huang et al., "Stacking Low Carbon Policies on the Renewable Fuels Standard: Economic and Greenhouse Gas Implications," *Energy Policy*, vol. 56 (May 2013), pp. 5-15 and Institute of Transportation Studies, University of California, Davis, "National Low Carbon Fuel Standard: Technical Analysis Report," Research Report UCD-ITS-RR-12-11, 2012.

Congress considers creating a national LCFS to complement or replace the RFS, several factors about the RFS may be instructive. This section briefly explores three of those factors.[54]

First, the RFS involves at least four sectors of the economy: energy, the environment, agriculture, and transportation. In general, the RFS involves the production of fuels (energy) made from renewable biomass (agriculture) used in vehicles (transportation) that must meet a GHG emission threshold (the environment).[55] Thus, different Members of Congress, federal agencies, and stakeholders may view the RFS from different perspectives. These differences in perspectives have, at times, led to challenges with proposals to amend the program, program implementation, and program compliance.[56] It is not clear if a national LCFS would generate the same differences in perspectives since LCFSs generally are structured differently than the RFS as described below.

Second, the RFS is a volume mandate. The statute for the RFS dictates how much renewable fuel is to be blended into the nation's transportation fuel supply each year.[57] The foundation of the RFS is the total annual renewable fuel volume required (in gallons). The foundation of existing LCFS programs has been the annual carbon intensity target (in gCO_2e/MJ). Existing models of LCFS programs do not dictate how much of a certain low-carbon fuel must be used; the LCFS program's primary focus is whether the average of all fuel supplied meets the CI target.

Third, in order to be eligible for the RFS, the fuels must be produced from renewable biomass.[58] The RFS does not incorporate fuels produced from other sources that may be considered "clean" by some stakeholders (e.g., natural gas, hydrogen, nuclear, wind, or solar). Additionally, the majority of the annual RFS mandate is met with liquid transportation fuel. Some might contend that other renewable sources or fuel types are not feasible for the present time or in the near-term as most vehicles use liquid fuels. Others might counter that the RFS excludes certain sources of clean energy (e.g., hydrogen) and limits the adoption of alternative vehicles (e.g., electric vehicles). An LCFS typically accepts eligible fuels from any source that meets the annual CI target.

The RFS and the CA-LCFS

The CA-LCFS and the RFS share a common goal: to reduce the GHG impact of transportation fuels. The programs have similarities and differences in how they achieve this goal. Provided below is a list of selected similarities and differences.[59]

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[54] The RFS is a complex policy framework. This section presents high-level information for certain aspects of the RFS that are immediately relevant to discussions about potentially adopting a national LCFS. This section does not discuss the interaction between the RFS and the CA-LCFS. For an example of one analysis that studies the interaction between the RFS and the LCFS, see Jarrett Whistance and Wyatt Thompson, "Chapter 10—The Impact of Key US Biofuel Policies: An Example of the US RFS and California's LCFS," in *Biofuels, Bioenergy and Food Security: Technology, Institutions and Policies*, ed. Deepayan Debnath and Suresh Chandra Babu (Academic Press, 2019).

[55] Eligible fuel for the RFS includes transportation fuel used in motor vehicles as well as jet fuel and home heating oil. However, the majority of the annual mandates thus far has been met with liquid transportation fuel used in cars and light-duty trucks.

[56] For example, there were several years early on in the program when EPA did not meet the statutory deadlines to announce the annual mandates and, more recently, EPA's issuance of small refinery exemptions have been a concern for some. Over the years, bills have been introduced in Congress that would have modified or repealed the RFS.

[57] The volume outlined in statute can be waived (i.e., reduced) by the EPA Administrator given certain conditions.

[58] 42 U.S.C. §7545(o)(1)(J).

[59] This section identifies some of the key features to consider if one wanted to compare the CA-LCFS and the RFS. CRS does not posit that the comparison of the two programs is an easy task. Indeed some researchers report that "By themselves, each policy [CA-CFS and RFS] has garnered quite a bit of attention in the academic literature, with most

Selected Differences

- **Primary goal of program.** The primary focus of the CA-LCFS thus far has been the reduction in the carbon intensity of California transportation fuels. It could be argued that discussions about the RFS have focused on multiple program goals, among them economic development of rural communities and reduced dependence on oil, and not solely the GHG impact of transportation fuels.
- **Program metric.** The CA-LCFS uses a CI benchmark (i.e., gCO_2e/MJ) as its program metric. The RFS uses volume (i.e., billion gallons) as its metric.
- **Program structure.** The CA-LCFS is concerned with whether a transportation fuel meets the CI benchmark.[60] The RFS is concerned with meeting the volumes set in statute and then finalized by EPA.
- **Transportation fuel resource.** The CA-LCFS applies to transportation fuels from fossil, alternative, and renewable resources. The RFS applies to transportation fuel made from one renewable resource: renewable biomass.
- **Transportation fuels.** The CA-LCFS is only applicable to transportation fuels. The RFS includes transportation fuels as well as home heating oil.
- **Geographic jurisdiction.** The CA-LCFS is a state program, applicable to fuel supplied in California. The RFS is a national program, that, in general, is applicable nationwide.[61]
- **Compliance program structure.** There are differences between the CA-LCFS and the RFS compliance programs. For instance, the CA-LCFS has a Credit Clearance Market (CCM) with a price cap. CARB reports that this price cap in the CCM "prevents extreme market volatility."[62] Further, under the CA-LCFS,

studies focusing the individual structure of the policies and perhaps their effects on related agricultural and energy markets or on their ability to meet certain climate or GHG reduction goals. Fewer studies have investigated the interaction between the two policies, and at least some of those that have done so use a hypothetical federal-level LCFS representation instead of a state-level representation." Jarrett Whistance and Wyatt Thompson, "Chapter 10 - The impact of Key US Biofuel Policies: An example of the US RFS and California's LCFS," in *Biofuels, Bioenergy and Food Security*, pp. 179-192. This CRS report does not cover how the CA-LCFS and the RFS may interact with each other. For more information on interactions between the programs, see Jarrett Whistance, Wyatt Thompson, and Seth Meyer, "Interactions between California's Low Carbon Fuel Standard and the National Renewable Fuel Standard," *Energy Policy*, vol. 101 (2017), pp. 447-455. CRS presents this information as a starting point for congressional staff engaged in policy discussions about the different approaches to address the greenhouse gas impact of transportation fuels.

[60] Some researchers report this LCFS program "flexibility gives obligated parties the option to blend whichever optimal mix of fuels satisfies their CI reduction obligations." Jarrett Whistance and Wyatt Thompson, "Chapter 10 - The impact of Key US Biofuel Policies: An example of the US RFS and California's LCFS," in Biofuels, Bioenergy and Food Security, pp. 179-192. Additionally, the researchers report "the LCFS does not require specific volumes of renewable fuel to meet the GHG reduction targets each year. The average CI of the motor fuel pool just has to equal the target level, and it is up to the obligated parties (i.e. fuel producers and importers) to determine the mix of fuels that will meet that goal." Jarrett Whistance, Wyatt Thompson, and Seth Meyer, "Interactions between California's Low Carbon Fuel Standard and the National Renewable Fuel Standard," Energy Policy, vol. 101 (2017), pp. 447-455.

[61] The RFS statute exempts noncontiguous states and territories, but allows them to opt in. 42 U.S.C. §7545(o)(2)(A)(ii).

[62] California Air Resources Board (CARB), "LCFS Basics," https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf. CARB reports "The CCM increases market certainty regarding maximum compliance costs, strengthens incentives to invest in and produce low-CI fuels, and reduces the probability of credit shortfalls and price spikes." CARB "LCFS Credit Clearance Market," https://ww2.arb.ca.gov/resources/documents/lcfs-credit-clearance-market.

credits do not expire.[63] In general, under the RFS, Renewable Identification Numbers (RINs) may be used to demonstrate compliance in the year they are generated and the following year.[64] The RFS has no price cap on RINs.[65]

Selected Similarities

- **GHG emission reduction.** Both the CA-LCFS and the RFS are designed to reduce GHG emissions from fuels. The CA-LCFS attains this by incorporating a GHG component into its metric (i.e. gCO_2e/MJ). The RFS attains this by including a GHG emission reduction threshold for each fuel category.[66]
- **Annual program.** The CA-LCFS and the RFS are both annual programs with an annual target and an annual compliance period.[67]
- **Multiple sector involvement.** Both the CA-LCFS and the RFS involve multiple sectors (e.g., energy, transportation, agriculture, and the environment) that may view each program from a different perspective.
- **Compliance system.** The CA-LCFS and the RFS both have a compliance system that requires regulated parties to demonstrate compliance using a credit system.
- **Market-based trading.** Both programs allow trading of credits in a financial market. Thus, obligated parties facing a deficit may be able to purchase credits from parties with a surplus.
- **Legal challenges.** Both programs have undergone numerous legal challenges.[68]

LCFS Considerations for Policymakers

An LCFS can potentially have a range of effects. The design, implementation, and enforcement of an LCFS will determine the quantity and magnitude of those effects. Should Congress choose to establish an LCFS, there are several items to consider. Some of those items include[69]

- Ability of the policy to respond to unknown events or unforeseen consequences (e.g., Will there be a scientific breakthrough or change in consumer demand for transportation fuel?),

[63] California Code of Regulations, 17 CCR §95487 "Credit Transactions." Some researchers report "Unlike the RFS, of which 20% can be met by RINs generated in the previous year, LCFS credits can be banked indefinitely and can be used to meet any of the future GHG reduction targets." Jarrett Whistance, Wyatt Thompson, and Seth Meyer, "Interactions between California's Low Carbon Fuel Standard and the National Renewable Fuel Standard," Energy Policy, vol. 101 (2017), pp. 447-455.

[64] 40 C.F.R. §80.1427(6)(i).

[65] Some in Congress have proposed a RIN price cap; see Jarrett Renshaw, "Exclusive: Senator Cruz wants to cap renewable fuel credits at 10 cents - document," *Reuters*, December 15, 2017. Others in Congress oppose a RIN cap; see Growth Energy, "Growth Energy Thanks Senate Biofuels Champions for Defeating Cruz's Midnight-Hour RIN Cap Amendment," press release, February 5, 2021.

[66] For instance, under the RFS, advanced biofuel must have lifecycle greenhouse gas emissions of at least 50% less than lifecycle greenhouse gas emissions from its gasoline or diesel counterpart. 42 U.S.C. §7545(o)(1)(B).

[67] Some researchers report the "RFS mandates are finalized annually, introducing considerable uncertainty into the market." Sonia Yeh et al., "A review of low carbon fuel policies: Principles, program status and future directions," Energy Policy, vol. 97 (October 2016).

[68] For a timeline of major court decisions on CA-LCFS cases from 2011 - 2015, see Sonia Yeh et al., "A review of low carbon fuel policies: Principles, program status and future directions," Energy Policy, vol. 97 (October 2016).

[69] The items are not listed in any order of priority and this list is not exhaustive.

- Connections between the LCFS and other incentives or programs (e.g., Will there be procurement mandates, tax incentives, or carbon capture and storage efforts that impact the LCFS?),
- Consumer choice (e.g., Will consumers prefer a certain type of fuel or vehicle?),
- Distributional effects (e.g., Who receives the environmental and monetary benefits? Who pays any costs for fuel transition?),
- Economic development (e.g., Will an LCFS create jobs?),
- Eligible fuel types (e.g., Will clean fuel or renewable fuel be eligible?),
- Equity (e.g., Will there be a transportation fuel equity analysis for the program? Who will have access and opportunity to participate in fuel production, credit trading, etc.?),
- Existing state programs (e.g., Will state programs fold into a national LCFS?),
- Global leadership and competitiveness (e.g., Can the United States serve as the world leader for developing clean fuel technologies and infrastructure?),
- Land use change (e.g., Is there a robust and reliable methodology to measure direct and indirect land use change?),
- Litigation (e.g., Are there potential legal challenges that may forestall program implementation and, thus, prevent program goals from being met?),
- Periodic program evaluation (e.g., Will there be scheduled time periods to review and modify the policy if needed?),
- Policy certainty (e.g., Will there be mid- to long-term regulatory certainty for producers, obligated parties, and others?),
- Potential dominance of one fuel type over other fuel types (e.g., Will there be a sudden transition to electric bus fleets by municipal and state governments or electric delivery vehicles by ecommerce businesses?),
- Program administrator and regulator (e.g., Should the same entity implement the program and regulate compliance?),
- Program compliance (e.g., Will program compliance consist of a credit system or a pass-fail system?)
- Program flexibility (e.g., How flexible or prescriptive will the policy be?),
- Program transparency (e.g., Will there be enough transparency to ensure confidence in credit transactions for compliance),
- Regional needs and ability (e.g., Which regions have the capacity to produce low-carbon fuel?), and
- Scientific and technical expertise (e.g., What science and technical experts are available to routinely and independently analyze the policy?).

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Union of Concerned Scientists

FACT SHEET

Clean Fuel Standards

A Proven Approach to Fuel a Low-Carbon Future

HIGHLIGHTS

Replacing petroleum with renewable electricity and other clean transportation fuels is among the most critical steps to stave off the worst impacts of climate change. Clean fuel standards are a proven part of the solution, holding the oil industry accountable for its actions while steadily driving down emissions. By connecting a fuel's value to its pollution, well-designed standards make clean fuels less expensive and dirty fuels more expensive. This supports the lowest-carbon fuels and drives down emissions from all fuels: from electricity to biofuels and even gasoline and diesel. As we scale up clean fuels and transportation electrification, it's essential that costs are shared equitably and that all communities benefit, especially those disproportionately burdened by transportation pollution.

Grappling with climate change requires transforming how we power our economy, and no sector requires more fundamental change than transportation, which accounts for the largest share of US global warming pollution. Most of the gasoline and diesel that power cars and trucks today must be quickly replaced with low-carbon alternatives. Given the size and complexity of the transportation system, this will require a variety of clean fuels, from electricity to hydrogen and liquid biofuels. In order to keep global temperature rise well below 2°C and aiming for 1.5°C, most vehicles must be electrified and the remaining combustion fuels must be nearly carbon neutral by 2050.

After a half century with petroleum as the only significant source of transportation fuel, post-2000 biofuel growth and post-2010 progress with electric vehicles (EVs) have persuaded even the auto and oil industries that change is real and accelerating. But replacing petroleum in transportation is a big job, and time is running out to avoid increasingly catastrophic outcomes from unchecked climate change. Meeting this challenge will require transformative changes and major investments throughout the economy, with implications for drivers, vehicle manufacturers, transportation fuel producers, and distributors. A comprehensive approach to climate policy will ensure that all of these industries and stakeholders are working toward a common objective.

A clean fuel standard is a proven policy approach to reducing transportation emissions that complements support for EVs and emissions standards for cars, trucks, and electricity generation. After being introduced in California in 2007, clean fuel standards have been implemented in Oregon and British Columbia and are being considered in Minnesota and other parts of the Midwest. A clean fuel standard focuses accountability on the oil industry and demands steady reductions in transportation fuels' carbon intensity (CI): the life cycle global warming pollution per unit of energy, from production to consumption.



Sounder Bruce/Creative Commons (Flickr)

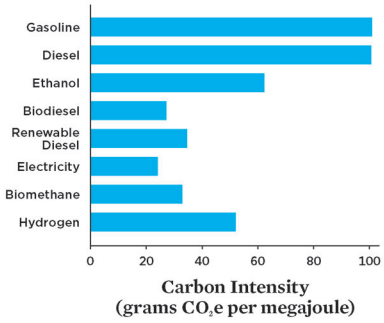
Transit buses are just one of the growing number of vehicles on today's roads powered by electricity instead of petroleum fuels. A clean fuel standard provides financial support for transit agencies operating electric buses, speeding the transition away from diesel.

What Is a Clean Fuel?

A clean fuel is an alternative transportation fuel or energy source with a CI lower than petroleum-based fuels (see Figure 1). For example, a small but growing share of the gasoline and diesel sold in the United States is composed of biofuels, principally ethanol, biodiesel, and renewable diesel. Today ethanol accounts for 10 percent of the gasoline sold in the United States and biodiesel is about 3 percent of diesel (EIA 2020b). Electricity is another clean fuel. As EV use increases, a small but rapidly growing share of transportation energy comes from a plug rather than a pump. Electricity will become a much more significant part of the transportation sector over the next several decades. Gaseous fuels like hydrogen, used in fuel cell EVs, and biomethane also power transportation without petroleum.

Assessing how clean a fuel is requires calculating its CI. For gasoline, this includes pollution related to oil extraction and refining operations alongside its tailpipe pollution. For electricity, this includes pollution from coal and natural gas power plants. For biofuels, additional factors include emissions associated with farming biofuel crops, biofuel production, and any emissions attributable to land use change (Martin 2017).

FIGURE 1. Average Life Cycle Emissions for Major Fuel Categories



Carbon intensity varies across fuel types, as shown above for major fuel categories. There is also variation within each fuel category, not shown, depending on how the fuel is produced.

Note: Emissions values represent volume-weighted average carbon intensity for each fuel category and are based on 2019 fuel sales in California.

DATA SOURCES: CARB 2020A; CARB 2020B.



Kenneth Keifer/Shutterstock

A clean fuel standard supports transportation fuels with carbon intensities below the standard, such as renewable power and low-carbon biofuels, based on a scientific assessment of the climate benefits they deliver.

This means alternative fuels will vary in their CI both between and within fuel types, depending on production details. For example, driving an EV charged primarily with renewable sources of power such as wind and solar will cause far fewer emissions than the same car charged on a grid powered primarily with coal and natural gas. Likewise, biofuels produced from waste products or a sustainably produced crop will have less climate impact than biofuels produced from palm oil, which is linked to deforestation. Even emissions from petroleum-based fuels can vary widely based on the source of the oil, how dirty it is, and how it is refined (Martin 2017).

How Does a Clean Fuel Standard Work?

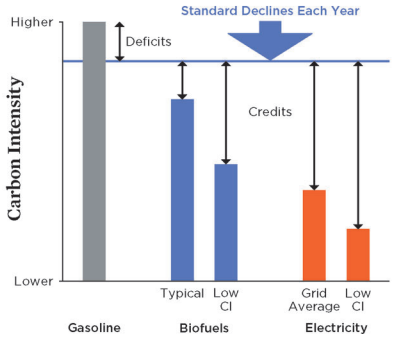
A clean fuel standard is analogous to existing standards requiring automakers to make cars more efficient and reduce tailpipe emissions, or those requiring utilities to reduce carbon emissions from electricity generation or to increase the share of renewable energy. Under a clean fuel standard, sellers of transportation fuel are accountable for reducing the CI of their products, regardless of where in the life cycle the emissions occur.

Yet the transportation fuel system is fragmented, with different types of companies selling different types of fuel. Even within a single fuel supply chain, different companies contribute to a fuel's life cycle emissions (e.g., oil extraction, refining, and blending with ethanol and biodiesel). A system of credits and deficits helps connect the different parts of the fuel marketplace to support the use of cleaner fuels, whether they are blended into the gasoline and diesel used by internal combustion vehicles, or are supplied by utilities over electrical lines and used by electric or other alternative-fuel vehicles.

A clean fuel standard relies on a complete and accurate life cycle assessment of each transportation fuel, based on up-to-date science. The standard sets a ceiling that applies to the *average* CI of all fuels sold for transportation use. Fuels with a CI *higher* than the standard generate deficits, and fuels *lower* than the standard (and therefore cleaner) generate credits. Over time, this ceiling is lowered (see Figure 2).

Sellers of fuels with a CI higher than the standard, such as gasoline and diesel, must either lower the CI of the fuels they sell or buy credits generated by suppliers selling fuels with a CI below the standard. This market for credits provides financial support for low-carbon fuels and creates an economic incentive for all fuel producers to reduce emissions in their supply chains. Any participant in the fuel marketplace and supply chain can benefit by lowering the CI of transportation fuels. For fuels such as ethanol and biodiesel that are blended with gasoline and diesel, a lower CI biofuel will have greater value because it provides more credits than a higher CI biofuel. Users of alternative fuels such as a public transit agency operating electric buses can also generate and sell credits to sellers of gasoline and diesel, creating a revenue stream to help transit agencies move quickly to electric buses.

FIGURE 2. Deficit and Credit Generation within a Clean Fuel Standard



A steadily declining standard for carbon intensity generates credits for fuels cleaner than the standard, and deficits for more polluting fuels. Clean fuel producers can sell credits to deficit holders, and all parties in the fuel supply chain have an incentive to seek lower-carbon fuel sources and production practices.

Unlike carbon taxes or carbon caps with credit auctions, the government does not collect or disburse funds under a clean fuel standard. The government's role is to oversee the scientific assessment, reporting, and verification of the fuel CIs, and track fuel use and transactions.

Holding Oil Companies Accountable

Emissions from petroleum fuels in the United States, most of which are used for transportation, exceed those from coal or natural gas (EIA 2020b). And oil companies, aided by their trade associations, have played a major role in funding ongoing climate denial campaigns and efforts to block climate policies for decades (Mulvey and Shulman 2015). In addition to holding them accountable for past harms, it is also important for the oil industry to help pay the cost of transitioning to cleaner transportation fuels.

A clean fuel standard requires oil companies to cover part of the cost of replacing combustion fuels with clean electricity while also spurring them to decarbonize the fuel for internal combustion vehicles. Electric cars and trucks generate credits based on how much they reduce emissions. When oil companies buy these credits, they are helping to cover the costs associated with transitioning the transportation sector away from oil.

To decarbonize the gasoline and diesel used by existing internal combustion vehicles, oil companies can blend low-carbon ethanol, biodiesel, or renewable diesel with petroleum-based fuels, or they can diversify their own operations to produce cleaner fuels. For example, some oil refineries have switched from making petroleum fuels to making renewable diesel. Oil companies can also reduce emissions associated with producing petroleum products, for example by replacing the natural gas used in oil extraction or refining with solar energy or biomethane. Oil companies can also implement carbon capture and sequestration technology to reduce net emissions.

Consumer Transportation Costs and Equity

A clean fuel standard, including the schedule for increased stringency, cost containment mechanisms, and the interaction with other policies, must be managed to accelerate the transition to clean fuels while controlling costs and ensuring that the benefits of cleaner fuels are equitably distributed.

When evaluating the net impact of a clean fuel standard on consumers' transportation costs, it is important to consider total household costs rather than cents per gallon of petroleum fuel. Steadily improving efficiency and moving from petroleum to EVs coupled with investments in public transit

and more walkable neighborhoods can reduce overall consumer transportation costs.

A clean fuel standard makes cleaner fuels more affordable and polluting fuels more expensive. However, existing disparities will be amplified if low-income people are left driving older, inefficient and polluting cars while more affluent people move quickly to EVs. An equitable path to clean fuels and transportation electrification must ensure that that costs are shared equitably and that all communities benefit, especially those historically overburdened by transportation pollution and other impacts (Reichmuth 2019). Specific provisions of a clean fuel standard can help, together with other measures that target support for electrification to disproportionately burdened communities.

Proof of Concept: Clean Fuel Standards Already Delivering Meaningful Reductions

The California Low Carbon Fuel Standard (LCFS), established in 2009, has driven a 70 percent increase in the use of low-CI alternative fuels. While ethanol initially generated the largest share of credits, the largest growth in emissions reductions during the first decade came from bio-based diesel fuels (biodiesel and renewable diesel), biomethane, and electricity (CARB 2020b). The value of LCFS credits for electricity grew to over half a billion dollars in 2019, and over the next decade, this growth should continue as EV use increases (CARB 2020b; CARB 2020c). Provisions enacted in 2018 also allow for carbon capture and sequestration in the fuel supply chain to lower the CI of fuels.

Conclusion

A clean fuel standard creates accountability for global warming pollution by requiring that all transportation fuel producers, starting with the oil industry, contribute to the decarbonization of transportation. It connects a fuel's value to its pollution, driving down emissions from all fuels—from gasoline and diesel to low-carbon alternatives such as electricity and hydrogen. It sets a common standard based on a scientific assessment of the full life cycle CI of each fuel. A clean fuel standard, together with strong pollution standards for vehicle manufacturers, support for transportation electrification and renewable power, and policies that reduce dependence on personal driving, can set us on a course to a clean transportation future.

Jeremy Martin *is director of fuels policy and senior scientist in the UCS Clean Transportation Program.*

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United States Senate

February 24, 2022

The Honorable Thomas R. Carper
Chairman
Senate Committee on Environment & Public Works
456 Dirksen Senate Office Building
Washington, DC 20510

The Honorable Shelley Moore Capito
Ranking Member
Senate Committee on Environment & Public Works
410 Dirksen Senate Office Building
Washington, DC 20510

Dear Chairman Carper and Ranking Member Capito:

Please accept this letter to be included in the record for the Committee's February 16, 2022, hearing entitled *The Environmental Protection Agency's Renewable Fuel Standard Program: Challenges and Opportunities.*

As you know, the corn ethanol mandate was originally included in the Renewable Fuel Standard (RFS) to reduce emissions, support farmers, and cut U.S. dependence on energy imports. However, numerous studies, including a recent peer-reviewed study published in the Proceedings of the National Academy of Sciences (PNAS), continue to show that requiring ethanol blending is counterproductive to achieving those goals. The PNAS study, "Environmental Outcomes of the U.S. Renewable Fuel Standard," found that ethanol is at least 24 percent more carbon-intensive than gasoline and that corn cultivation has expanded into 6.9 million additional acres of land, leading to the tilling of cropland that would otherwise not have been used for corn production.

Our bill, the "Corn Ethanol Mandate Elimination Act of 2021" (S. 2385), would end the corn ethanol mandate in the RFS to allow for more productive land use and decreased greenhouse gas emissions. We encourage the Environment and Public Works Committee to consider this legislation as changes to the RFS are made.

We believe the U.S. should prioritize our agriculture in the service of feeding people. Additionally, the corn ethanol mandate has increased the price of corn and products made from corn, such as livestock feed. This has made it more expensive for families to put food on the table. Finally, as fuel economy standards and increased vehicle electrification drive down gasoline consumption, the RFS should be updated accordingly. Our bill would amend the RFS to remove the

volume requirements for corn ethanol, while leaving in place the advanced biofuels categories, including cellulosic biofuel and biodiesel. We look forward to working together towards cleaner transportation fuel options.

Thank you for your consideration of our request. We would be happy to discuss this legislation and issue further at your convenience, or have your staff contact Rishi Sahgal at Rishi_Sahgal@feinstein.senate.gov and Wesley Wright at Wesley_Wright@toomey.senate.gov.

Sincerely,

Dianne Feinstein
United States Senator

Pat Toomey
United States Senator

○