RFF | *Published since 1959 by Resources for the Future* | NO. 215 | SPRING 2024

Resources

POWERING UP POLICY DECISIONS FOR THE US ELECTRIC GRID

FUTURE OF ELECTRICITY
Evolving electricity markets in a decarbonized world

PERMITTING REFORM
Speeding up solar energy projects

EXPANDING TRANSMISSION
Modernizing the US electric grid

TAX CREDITS
Easier clean electricity with the Inflation Reduction Act

Illustration by Nils-Petter Ekwall

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A Note from RFF's Newly Appointed President

Plugging Into Powerful Solutions

Hello to our *Resources* readers. I am very excited about assuming the leadership mantle at Resources for the Future (RFF) as of May 1 and look forward to connecting with you in various ways in the months and years ahead.

For many of us, the US presidential election this year dominates the landscape. Observers might suppose that little consequential policymaking will happen in the lead-up to November. However, for the electric power grid, key guidance and rules from federal regulators may shape the future of US electricity for years to come.

Two such regulations have been the talk of academics, government officials, industry leaders, and communities for years. The Federal Energy Regulatory Commission—a federal agency tasked with regulating interstate transmission of electricity, natural gas, and oil—is working to implement its anticipated new rule on electricity transmission planning and cost allocation. In addition, the US Environmental Protection Agency recently released final guidelines under Section 111 of the Clean Air Act, specifying emissions guidelines for existing coal plants and new natural gas plants. (The rule for existing natural gas plants has been delayed until after the election.) Meanwhile, states are anticipating these changes and already are accelerating electric-grid technologies to improve an aging grid and work toward decarbonization goals.

At RFF, we have been tracking all these developments. In this issue of *Resources* magazine, we amplify some of the work we've been doing across RFF's Electric Power Program, led by Senior Fellow Karen Palmer. This timely work includes analysis of how the Inflation Reduction Act and its implementation continues to impact this critical part of our energy system, new tax credits created to advance solar and wind technologies, and potential shortfalls of some of the most ambitious policy advancements.

In a *Resources Radio* episode at the start of this year, Karen lamented that we hadn't seen much movement in 2023 on overcoming key barriers to investment in the electric power grid. Despite the election year, we anticipate substantial movement in 2024 toward net-zero emissions, and RFF researchers, along with our partners, are tracking and analyzing it all moving forward. In addition to reading what's in this issue of *Resources* magazine, continue to check the RFF website for events, publications, and more analysis on what's to come.

We hope you'll stay plugged into RFF as we continue to power our rigorous research and engage decisionmakers on widespread decarbonization of the electric power sector—a necessary step toward addressing climate change.

Sincerely,

Billy Pizer

Billy Pizer
President and CEO, Resources for the Future

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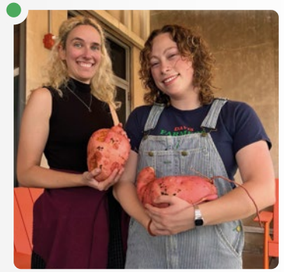
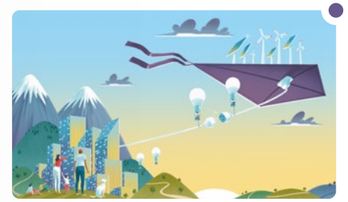
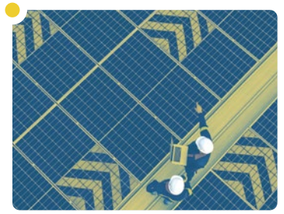
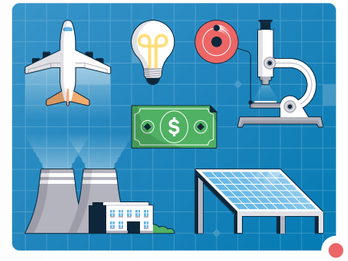
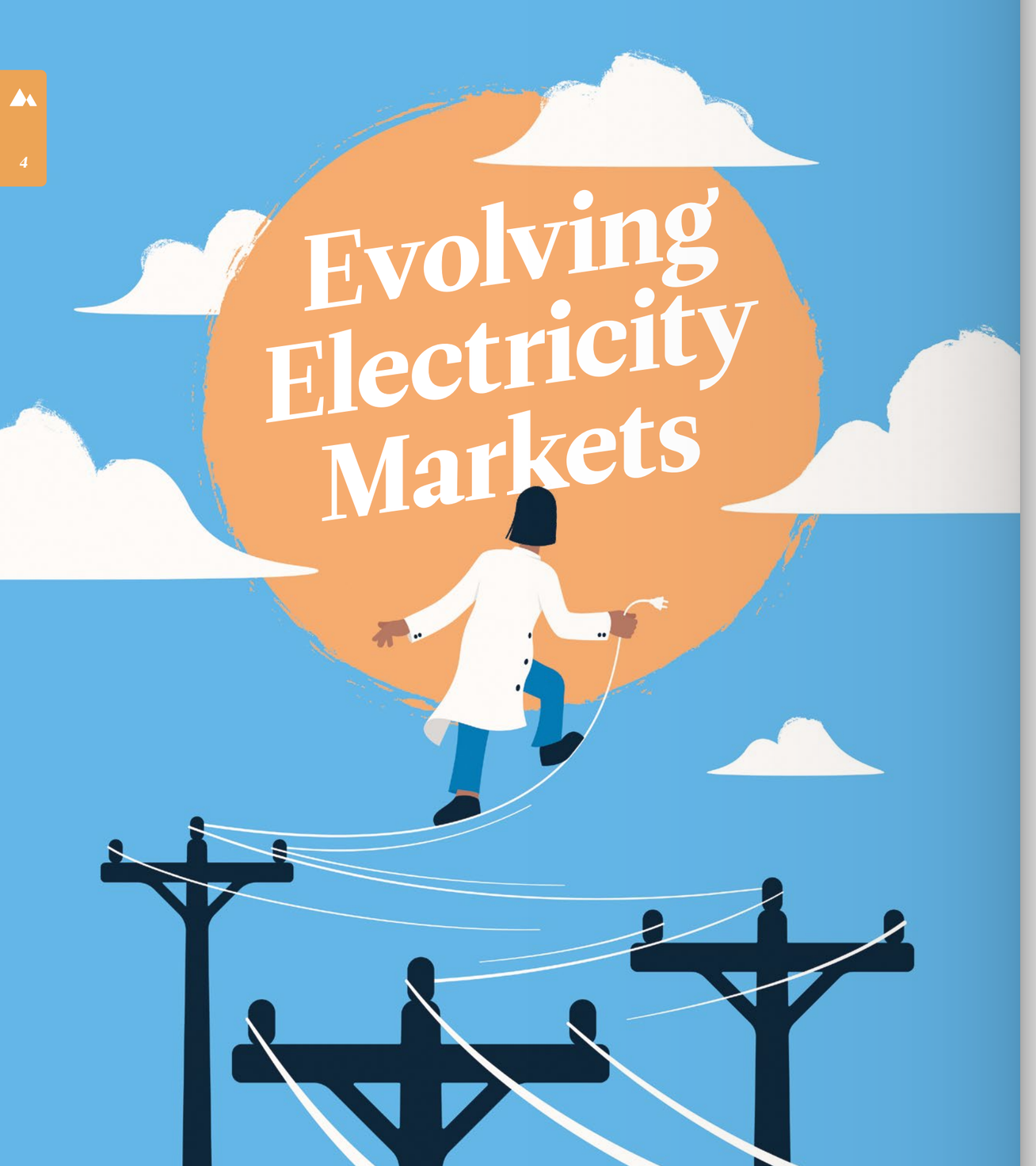










Evolving Electricity Markets

A CONVERSATION WITH
Karen Palmer and
Molly Robertson

ILLUSTRATION
Francesco Ciccolella

What will US electricity markets look like in an emissions-free world? Economists at Resources for the Future (RFF) are always thinking about how markets operate and evolve in a world where policy and technology are constantly changing.

With the power sector going through a massive transformation as it continues to decarbonize, *Resources* magazine sat down with RFF Senior Fellow Karen Palmer and Senior Research Associate Molly Robertson to discuss what this transformation means for wholesale electricity markets and how current systems will need to adapt.

***Resources*: Let's start out by setting the scene. How do electricity markets work today?**

Molly Robertson: Wholesale electricity markets look different across the country and across the globe. The United States has a mix of what we call deregulated electricity markets and vertically integrated electricity suppliers.

Prior to the 1990s, almost all electricity users were served by vertically integrated monopolies which owned the generation, transmission, and distribution systems that delivered electricity from power plants to households. This structure meant that wholesale markets played a very limited role in determining which generators provided power. In these monopolies, utilities were heavily regulated, and prices were set by regulators so that utilities could cover their own costs, thereby limiting the ability of utilities to charge monopoly prices.

During the 1990s, a wave of restructuring took place, which took advantage of the fact that the generation component of the electricity system could be part of a competitive market. Several regions of the United States created competitive markets to provide electric power; these markets allow generators to offer bids in an auction, and the lowest-cost generators are selected by an independent system operator to provide power. This system of competitive markets is common today, although vertically integrated utilities are still operating in some regions.

Karen Palmer: The markets that are run by the independent system operators are structured to provide an incentive for generators to bid into the competitive energy market at their marginal cost of producing electricity. At that price, the generator is indifferent to either operating and receiving the price, or not operating and saving the fuel and other operating costs.

Generators are selected for operation starting with the lowest bid price. When an auction price reaches a value that ensures equivalent supply and demand of electricity; the market has "cleared." For electricity markets, generators make money when the clearing price is higher than their marginal cost. These monetary gains go toward paying down the fixed costs incurred by the generators and, hopefully, contribute to profits.

What happens if a generator isn't selected to operate during the auction process?

KP: If a generator's marginal costs are consistently higher than the marginal costs of competitors, then the generator may clear the market only at rare times when demand peaks or when other generators are out of service. In some cases, these infrequent periods of operation yield revenues that are sufficient

"During the 1990s, a wave of restructuring took place, which took advantage of the fact that the generation component of the electricity system could be part of a competitive market."

to cover the generator's costs. If particular generators can't operate often enough to earn revenues that are sufficient to cover their fixed costs, then those generators are forced to retire.

MR: The energy market, in which generators are paid to provide electricity to the grid, is the main way that most generators make money.

But for the grid to operate reliably, other services are required, which generators could provide for a fee that helps cover the costs. For example, generators may sell capacity commitments, which require the generators to be available just in case their power is needed. The payments for capacity commitments can be an important source of revenue for generators that don't expect to operate often but still may be needed in times of high demand.

Generators also may sell something called ancillary services, which refer to a suite of services that help grid operators keep their very complicated technical systems running smoothly. For example, a frequency-response service allows generators to sell the system operator very small, instantaneous adjustments in the generator's output to ensure that the grid maintains its necessary operating frequency. Only some generators have the ability to make those very small changes in generation instantaneously. Batteries have been highly valuable providers of frequency-response services. Ancillary services generally are low-price products, but they're still meaningful in the revenue stream for some generators.

Markets have to accommodate a lot of components in a well-functioning power system. How do wind and solar resources play into all this?

MR: Renewable energy resources like wind and solar are different from other resources, because the fuel they use to create electricity is free. When wind and solar resources offer their bids in the energy market, they typically can undercut the fossil fuel competition. In some cases, subsidies that compensate renewable generators for operating encourage renewable generators to offer negative bids into the market—the generators essentially offer to *pay* the market to allow them to operate and collect the subsidy.

At low quantities on the grid, renewable resources are all upsides: low-cost, zero-carbon resources.

At high levels of penetration, however, renewables challenge current market mechanisms by decreasing electricity prices and therefore decreasing the expected revenue in the day-ahead and real-time energy markets. Uncertainty over these low prices may make it more difficult for developers to determine if they should invest in new electricity generation.

KP: The other key characteristic of renewables is their intermittency. The fuel may be free, but it can't be controlled by the operator. A solar farm doesn't have to pay for sunshine, but it also can't change the weather if the forecast calls for clouds and rain. Although wind and solar may offer low-cost electricity during many hours of the day, they may disappear altogether at other times. To ensure that these situations of intermittency don't lead to outages, the grid has to find a way to ensure that enough backup resources are ready to jump in. Because these backup resources are operating infrequently, the generators have fewer hours of potential operating revenues available to recover costs.

Many market observers expect that a market with high penetration of renewable energy will face very large swings in energy prices as the generator that sets the auction clearing price switches between the low-cost renewables and the expensive backup resources. In some cases, auction-clearing energy prices may exceed the cost of the backup resources if the willingness to pay for additional energy, known as the value of lost load, exceeds the offer price of the backup resources. Prices set at this relatively higher level could signal the value of future investments, but such pricing is generally restricted by regulator-imposed price caps.

Are big price swings in wholesale markets a problem for generators?

KP: Price swings driven by variable resources pose a problem in terms of the long-term investment signals for power generators, particularly because the frequency of high-cost periods hinges largely on weather patterns that are difficult to predict.

Generators are expensive, and they take a long time to build, particularly with layers of permitting and interconnection systems that can add years to development timelines. Investing in generation becomes increasingly risky because large swaths of time could pass during which expensive generators may expect to make no revenue, and the generators would need to make sure they are available during the hours that prices spike, so they can recover their costs. The uncertainty over the frequency and duration of those price-spike periods makes it difficult for generators to obtain the necessary financing for significant project investments.

MR: These price swings could be mitigated through solutions such as building up storage technologies and allowing electricity users to respond to prices. By holding power in batteries or other technologies, energy-storage operators can buy excess energy when the energy is cheap (like when the sun is shining) and can make stored energy available for sale in the market when prices go higher (like when the sun goes down).

On the demand side, opportunities are available for electricity users to reduce their consumption during times of high prices. For example, a customer may plan to charge their electric vehicle in the middle of the day when prices are low due to the availability of solar power. Or a large industrial plant may agree to pause operation if electricity prices are sufficiently high. For demand response to deliver these benefits, electricity users must be exposed to these price swings and adjust their behavior accordingly.

For both demand response and storage, we still have questions about how much we can expect these options to contribute to solving the problem of price swings. For example, if we see a sustained shortage in renewable resources and associated high prices, on the order of weeks in duration, then storage and demand response may be insufficient to address system needs.

So, integrating renewables comes with opportunities and challenges. What kinds of adaptive measures could help address these issues?

KP: Economists are considering how redesigning electricity markets could improve investment signals and ensure that the generators which are needed on the system can make sufficient revenue to continue operating.

Current market structures rely on different mechanisms, such as capacity markets, power purchase agreements, minimum contracting obligations, or shortage prices, to facilitate enough power on the grid to serve demand. But those mechanisms may be insufficient or inefficient in procuring the right mix of resources.

Jurisdictions outside the United States are exploring different ways of signaling the need for investment in important new resources, like forward contracts for energy (in which both parties agree to buy and sell energy at a specified price on a future date) or contracts for differences (where power buyers pay generators the difference between the contracted price and the variable-energy market rate when the former is greater, and vice versa when the latter is greater), both of which can provide a stable, long-term revenue stream. Such solutions may provide more certainty for investors and help stabilize revenue streams for generators, but the details of these solutions matter for determining what types of energy projects actually get built and how much the systems cost to operate.

As reforms to the electricity market are considered, what priorities should regulators keep in mind?

MR: We think about evaluating changes to electricity markets in various ways, and whether the changes can meet the needs of the system.

First, solutions should enable the market to find low-cost approaches to meeting the needs of the grid, whether these approaches involve examples like meeting demand in real time or ensuring that the operating frequency of the grid is maintained.

Second, reforms to market structures should be built in a way that enables new and emerging technologies, which have different attributes, to provide services and compete.

Third, solutions should consider not only the ability of generators to increase supply, but also of customers to reduce demand.

Finally, as decarbonization policies at the state and federal levels continue to evolve, market-design solutions should be developed with the impact of those policies in mind. For example, if a state climate policy will require backup fossil generation to retire by a certain date, then markets should provide sufficient signals for new sources of non-intermittent clean generation to be built by that date.

What is RFF doing in this space to inform policymakers?

KP: We are spinning up work in this space and have a lot of ideas for how we can contribute to the policy dialogue. In an ongoing collaboration with Chiara Lo Prete of Penn State University, we are reviewing existing research and the international policy space to explore potential solutions to these market challenges.

The next phase of our work will involve a model of the power sector. We'll explore a subset of proposals in greater detail with the model to see if the proposed solutions could improve signals for investors.

We also are thinking about the role of emerging technologies in electricity markets, such as energy storage, and the challenges related to fitting them into the current structure.

Finally, we are continuing to think about the responsiveness of electricity consumers to price variation, so we can quantify the opportunity for demand-side participation in electricity markets.

This full range of work will inform conversations about designing electricity markets for a net-zero future. ■

“As decarbonization policies at the state and federal levels continue to evolve, market-design solutions should be developed with the impact of those policies in mind.”

Karen Palmer is a senior fellow and director of RFF's Electric Power Program, and **Molly Robertson** is a senior research associate at Resources for the Future.

Understanding the Inflation Reduction Act

The Inflation Reduction Act passed into law in August 2022. Already, the law has begun driving low-carbon investments—though additional policies could help the United States decarbonize by midcentury.

The Inflation Reduction Act (IRA) has been in force for the past year and a half, and the law's provisions for clean technologies have begun to bear results. In January 2023, a solar-panel manufacturer invested $2.5 billion in a pair of facilities in Georgia as a result of the IRA. The US Department of Energy has loaned more than $10 billion to firms for building facilities that will manufacture batteries for electric vehicles, and loan applications in the agency's queue total over $100 billion.

Despite a year of high interest rates, a clean energy economy is growing.

Yet, experts project that the United States will fall short of its near-term emissions-reduction goal to cut 2005 emissions levels in half by 2030, to the tune of about 10 percent below the goal. Hence, policies to complement the IRA are likely necessary.

Familiar ideas for reducing emissions remain in discussion, such as a tax on carbon emissions, which many economists endorse. The idea of a carbon border adjustment mechanism has attracted interest in the US Senate, and the federal government has proposed regulations to target emissions from specific sectors of the economy. Debates over permitting reform, which could accelerate the pace at which new energy projects are approved and built, have spilled from wonkier circles into the mainstream.

So, what is the future of US climate policy in an IRA world? Resources for the Future (RFF)

Photo (previous page)
Jon Hicks / Getty Images

Fellow Aaron Bergman spoke with Catherine Wolfram—an RFF university fellow, member of the RFF Board of Directors, and professor at the Massachusetts Institute of Technology, who also served at the US Department of the Treasury as the Deputy Assistant Secretary for Climate and Energy Economics—to examine the law's influence on future policymaking in the United States and abroad, sector- and state-level efforts at decarbonization, and how RFF can inform climate policy moving forward.

Aaron Bergman: When the IRA was introduced and passed, it was kind of a whirlwind. Nobody expected it, and the IRA was the most significant piece of climate policy that the United States has ever seen. When you first saw that the IRA passed, what had been your expectation, and what was your reaction?

Catherine Wolfram: I had written it off. When the IRA first passed at the end of July, I was in a hotel room in Brussels, talking to folks about the price cap on Russian oil. I got a text from my boss about it. It hadn't even been on my mind that something actually might come through. The next day, in meetings with our European counterparts, it was obvious that they were extremely excited that the United States was back at the table and taking climate change seriously.

In the fall of that year, a lot of debate revolved around whether environmental economists may have delayed progress on climate policy by overemphasizing the need for carbon pricing in efforts to decarbonize and mitigate climate change. For obvious reasons, I defend the environmental economics profession. But I also feel like we ended up at the mercy of one person's preferences. If Senator Joe Manchin (D-WV) had wanted a carbon price, we probably would have gotten a carbon price. Drawing sweeping conclusions about the direction of US politics from one person's preferences seems misguided to me. But that's what you get with such a close vote; one person's preferences can dictate a lot of it.

We now have a goal of reaching net zero by midcentury. The IRA has made a lot of progress toward that goal, but we still have a lot to do. What's next for climate policy after the IRA?

I think we could envision a couple next steps. One, I've heard people make this point—which I think is valid—that the IRA makes decarbonizing the electricity sector really cheap, for instance. You could imagine states adopting increasingly strict renewable portfolio standards in a kind of virtuous cycle where, because of the IRA subsidies, accelerating toward goals at the state level becomes politically more possible. I think that's one direction.

I also feel like the IRA does a lot with electricity, a lot with transportation, and maybe a bit with industry. It kind of depends on how you see carbon capture, utilization, and storage being adopted by industry. If the 45Q tax incentives aren't taken up by industry, then the sector's carbon emissions will continue to be hard to abate, with industry as the next frontier for climate policy.

More as hopecasting than forecasting: You could imagine a scenario in which the Trump tax cuts expire in 2025 as interest rates and deficits go up. We'll want to put the tax cuts back in place, but we'll be looking for revenue sources. I could imagine some kind of carbon price, at least in the industrial sector.

I'd also say it's important to think about how our approach to climate change mitigation relates to international trade. How US policies interact with European policies will be important going forward. Most of the rest of the developed world has some form of carbon pricing. The Clean Competition Act, a bill introduced by Senator Sheldon Whitehouse (D-RI), envisions something that resembles a carbon price—the bill proposes a border adjustment mechanism that's paired with a fee (the bill doesn't use the term "carbon tax") on industrial facilities that are above the median in terms of pollution. It's like a "dirty-emitters fee," which ratchets down over time. You start at the top half of facilities, charging those that exceed median emissions, and over time expand the number of facilities that are paying the fee. I could imagine a future of focusing on decarbonizing the industrial sector, which, because of pressure from our trade partners, could be a carbon price.

Do you think that a sector-based approach, with a combination of the current policies and decarbonizing the industrial sector, can get us to net zero? Or will we eventually need to think about a more unified approach?

I don't see the distinction quite so starkly. For example, if various sectors of the economy embrace carbon capture, utilization, and storage, we'll see spillovers across the sectors, and if the industrial sector develops new methods of transporting and storing carbon dioxide, the power sector will get those benefits, too.

I do think that a sectoral approach is the most likely outcome, although I imagine that we'll see spillovers across sectors.

I think it's interesting that the IRA is a kind of continuation of laws that have passed. The law includes a lot of tax credits and incentives—a lot of carrots, and not a lot of sticks. But, in many ways, the IRA is a departure from the American Clean Energy and Security Act and other prior big climate bills. In addition to a sectoral approach, carbon border adjustment mechanisms, and maybe even a carbon tax in the industrial sector, all of which you've mentioned, what other sectoral policies could get the United States to our emissions goals in the post-IRA world?

I've been thinking a lot about methane emissions. From a trade perspective, the IRA contains references to methane from the oil and gas sector that are more aligned with what some of our trading partners are doing. I can imagine some kind of agreement with the Europeans, or an even broader set of countries, on a methane border adjustment policy based on the regulations that the US Environmental Protection Agency is working on and the methane fee that's in the IRA.

A sector-based approach could be easier and a good glide path to something broader. For example, if the United States works with Europe on methane, we could make a lot of progress on methane emissions in some of the most highly polluting countries. In doing so, the United States also could gain experience working with Europe on border adjustments, climate change, and trade issues.

This doesn't exactly answer your question about meeting US climate goals, as the IRA already has some serious methane provisions, but a trade agreement could lead to some very meaningful reductions worldwide.

I think the sector-based approach lets us have those conversations without having to talk about the whole entire climate change problem, and the whole economy, and all the carbon emissions in the world. Maybe we could consider it a lower-stakes way to have some productive conversations.

The electricity sector has a huge menu of policy options, and you've talked about decarbonizing the industrial sector. What policies have potential to decarbonize the transportation sector?

I think that the Infrastructure Investment and Jobs Act, and its investments in charging stations, are important. The economics literature suggests that a dollar spent on charging infrastructure is very productive—more productive than a dollar spent on vehicle subsidies. We're already employing this option, but I would definitely include more charging stations in the list for future consideration.

I don't see much potential for a carbon price on gasoline. We might get to that eventually, but a lot of sensitivity surrounds gas prices, which makes a carbon price on gas somewhat unrealistic.

The IRA looks a lot like it's a technology policy. Billions of dollars of investment are in the IRA, including demonstration funding and other subsidies for deployment. What do you think of subsidizing technology in the hope of pushing down prices?

Theoretically, both a carbon price and a subsidy could get us to similar outcomes in terms of innovation. But if you think like an investor for, let's say, direct air capture or small modular reactors, it's probably a lot easier to estimate the amount you'll get from a direct subsidy—whereas with a carbon tax, you need to work a bit harder to figure out what the wholesale power price will amount to, and how that figure translates into profits.

I think the certainty of the amount of money that you'll get under the subsidy, and the IRA's

> "The Inflation Reduction Act makes decarbonizing the electricity sector really cheap."

> "The economics literature suggests that a dollar spent on charging infrastructure is very productive—more productive than a dollar spent on vehicle subsidies."

10-year time span, could be quite valuable for nascent technologies.

It's also encouraging that the tax credits for renewable electricity are technology neutral starting in 2025; I think that's a step in the right direction. If small modular reactors (or some other technology we haven't even heard of yet) become cheap, then that's the technology we'll build.

Also, at a non-economic, moral level, I think it's important to recognize that the energy transition is going to hurt some people and that we need to do what we can to support them. I think some of the add-ons in the IRA do that.

Do you think this focus on technologies is short term, or do you see it as being part of climate policy for a while?

I think technological innovation is important, because technologies are one of the main things we can export to the rest of the world. Figuring out how to influence the behavior of suburbanite Americans doesn't necessarily do much good in driving down the costs in Vietnam and China and India.

On the other hand, if we can figure out how to make cheap hydrogen and use hydrogen for steel production in a way that's valuable for the rest of the world—that will be something we can export. I think that's another advantage of going the technology route.

Another feature of the IRA has been a policy of industrial onshoring, which may not make our trading partners happy. What do you think this means both for US climate policy going forward and for international cooperation on climate policy?

I think the climate and trade issues are super important. I fear a negative outcome. In a worst-case scenario, all this could lead to the dissolution of the European Union Emissions Trading System, because the big member states really want to subsidize, but the smaller member states can't afford it; meanwhile, European governments are getting political pressure from industries that are trying to compete with subsidized counterparts in the United States. Those reasons could make it

Above President Joe Biden signs the Inflation Reduction Act in August 2022.

Drew Angerer / Getty Images

> **"I think technological innovation is important, because technologies are one of the main things we can export to the rest of the world."**

> **"I think the true cost of the Inflation Reduction Act could end up being a lot more than $369 billion ... but it could be less than that."**

hard to sustain the EU Emissions Trading System. I hope this outcome doesn't come to pass—and the Europeans seem committed—but we're not making it easy for them.

I think and hope that outcome is unlikely, but I do think we need to pay attention to these climate and trade issues and figure out a way to work productively with our trading partners. If we're pushing technologies down the learning curve, let's make sure that we use trade to diffuse those technologies and that they're adopted in other parts of the world.

We're in a regime now in which we're paying lots of money out of the federal government to lots of people, which creates an entrenched interest. What does the transition *out* of the subsidy regime look like? At some point, will we need an economy-wide policy? Or is that something that may never happen—or, at least something we won't need to worry about for a while?

I see this sector-based approach as a kind of gateway to an economy-wide strategy. For example, we might impose a carbon price in the industrial sector, which raises money, which in turn persuades people that we could find revenue in other similar ways, as well. Getting to a carbon price may be easier with baby steps rather than a wholesale flip.

I also think about carbon border adjustment mechanisms. If Canada imposes a carbon border adjustment mechanism, and US industry winds up facing those prices when we export to some of our big trading partners, but the Canadian Treasury collects that money and not the US Treasury, then the United States will have lost an opportunity. I could see carbon border adjustment mechanisms starting to look compelling if those types of policies progress globally.

Another thing to note on subsidies: To date, we actually have had carbon pricing, but just in the form of renewable portfolio standards. We've basically been funding those types of mandates at the state level. Essentially, we've been funding the climate transition on the backs of utility ratepayers, which is regressive. The IRA gets taxpayers to foot some of the bill, which indicates that, from a distributional perspective, we're moving toward solutions that are more progressive. Even if we're moving away from imposing costs and toward subsidies, I think the distributional implications are something to pay attention to, as well.

And one further thing on subsidies: The media has been reporting "$369 billion" offered in the IRA as though it's a super precise number and that the US Treasury is going to write a check for that exact amount. I think it's important to note that these tax credits aren't capped, and there's a wide range of uncertainty. For example, if lots of barriers to permitting prevent construction of new renewables, or renewable developers have trouble with transmission interconnections, or interest rates go up, then we won't see very much new wind and solar, and the government won't be issuing many tax credits. Clean energy technologies are particularly sensitive to the cost of capital—more sensitive to capital costs than natural gas. To the extent that interest rates keep going up, the investments that the IRA is subsidizing could get more expensive.

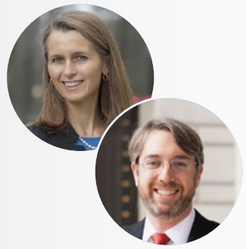
I think the true cost of the IRA could end up being a lot more than $369 billion—or, it's looking unlikely, but it could be less than that.

On the other hand, the impacts of the IRA on the macroeconomy aren't that big. You can imagine that the impacts could be big in certain parts of the country that invest a lot in wind or solar. We can draw an analogy to the shale boom: The expenditures on fracking weren't big enough to move the needle on unemployment nationwide, but in certain sectors and in certain regions, the impacts were large.

What can RFF do to move the climate policy conversation forward?

I'd rephrase that as, What can RFF *continue* to do? I think RFF's modeling is extremely valuable. I'm a fan of RFF's Carbon Scoring Project; having concurrence between the fiscal cost and the emissions estimates is important. The work that RFF has done on carbon border adjustment mechanisms, and ongoing work on hydrogen-fuel technologies and the 45V tax credit introduced in the IRA for hydrogen, is all super worthwhile.

I think hundreds of economics papers will be written on the IRA, so it's an exciting time for the profession. ■



Catherine Wolfram is a professor at the Massachusetts Institute of Technology and a university fellow and member of the board of directors at Resources for the Future.
Aaron Bergman is a fellow at Resources for the Future.

NO. 215 | SPRING 2024 | *"Cost distortions will diminish, and value distortions will increase."*

Tax Credit Choice for Solar and Wind Power in the Inflation Reduction Act

The Inflation Reduction Act has invigorated incentives for clean energy, including the investment tax credit and production tax credit. Wind and solar projects can choose between the two: What influences this choice, and what are the implications?

TEXT Jay Bartlett

To achieve a substantial decrease in US greenhouse gas emissions, the Inflation Reduction Act (IRA) relies primarily on subsidies for clean energy technologies, particularly tax credits for corporations. The massive amount of funding for corporate tax credits comes from increasing the values and durations of clean energy tax credits and expanding eligibility to new technologies. Additionally, the IRA allows all projects that generate clean power to choose between two incentive structures: the investment tax credit (ITC) and the production tax credit (PTC). Although wind projects previously have had the benefit of incentive choice, this option is novel for solar power.

For utility-scale solar and wind projects, the choice between the ITC and PTC will be determined by three types of owners: project sponsors, tax equity investors, and regulated utilities. The choices these owners make will have substantial effects on clean power deployment and investment supply. Furthermore, the choice of tax credits affects the efficiency of the IRA, as both investment- and production-based incentives can distort project decisions.

Background on the Investment Tax Credit and the Production Tax Credit

US federal incentives for renewable energy technologies have taken the form of either the ITC, a tax credit based on capital cost, or the PTC, a tax credit based on the amount of electricity produced.

The business ITC was established in 1978 and increased from 10 percent to 30 percent in 2005. Although technologies other than solar power have been eligible for the ITC, solar projects received nearly all ITC funding before the IRA.

> **"The choices these owners make will have substantial effects on clean power deployment and investment supply."**

Photo
Witthaya Prasongsin / Getty Images

> **US federal incentives for renewable energy technologies have taken the form of either the investment tax credit, a tax credit based on capital cost, or the production tax credit, a tax credit based on the amount of electricity produced.**

The PTC was established in 1992 at a rate of 1.5 cents per kilowatt-hour, and this rate applied for 10 years after a facility was placed in service. The PTC is adjusted annually for inflation, giving it a statutory rate of 2.75 cents per kilowatt-hour in 2023. As with solar and the ITC, onshore wind has received the most PTC funding to date.

Before the IRA, both the solar ITC and wind PTC had been scheduled to step down over time. COVID-19 relief legislation in December 2020 set the PTC to 60 percent of its statutory rate for wind projects that started construction in 2020 and 2021, with a planned expiration in 2022. The same legislation set the ITC to 26 percent for solar projects starting in 2021 and 2022, 22 percent in 2023, and 10 percent thereafter.

How the Inflation Reduction Act Has Changed the Investment Tax Credit and the Production Tax Credit

To assess the choice between the ITC and PTC, it is necessary to review the other changes that the IRA made to these two incentives. First, the IRA restored the ITC and PTC to their full statutory amounts—30 percent and 2.75 cents per kilowatt-hour (in 2023$), respectively. Second, the credits will remain at those levels for projects that commence construction by 2032 (if not later) if projects meet the requisite standards for prevailing wages and apprenticeships. Third, the IRA established 10 percent bonus credits both for meeting domestic content requirements and for establishing in an energy community. For the PTC, each bonus credit adds 10 percent of the PTC value, but for the ITC, each bonus credit adds 10 percentage points—a 33 percent increase in value.

Perspectives and Implications of the Choice between the ITC and PTC

The impacts of the choice between the ITC and PTC will be determined by project sponsors, tax equity investors, and regulated utilities, each with distinct incentives and constraints. Utility-scale solar and wind projects have been predominantly owned by independent power producers, in which the producer is the project sponsor, but ownership also includes a tax equity investor. In regulated markets, utilities may own generation assets but are subject to the constraints of state regulators and various requirements.

Project Sponsors

The project sponsor would prefer the tax credit that provides greater present value. Whether a 30 percent ITC is worth more than a 10-year PTC of 2.75 cents per kilowatt-hour depends primarily on three project factors: capital cost, capacity factor, and discount rate. A higher capital cost increases the benefit of the ITC, whereas a greater capacity factor increases the amount of electricity produced and thus the PTC's value. A higher discount rate (determined by the cost of capital) will diminish the present value of the PTC. Additionally, if the project qualifies for bonus credits, the credits are proportionately more valuable under the ITC.

In allowing projects to choose their preferred tax credit, the IRA has made both the ITC and PTC more beneficial. However, for utility-scale solar and onshore wind projects with low capital costs or high capacity factors, the PTC is significantly more generous. Consequently, the switch to the PTC for utility-scale solar projects is likely to cause substantial growth in clean power.

Tax Equity Investors

Tax equity investors are essential for efficient use of the tax credits and deductions for projects that are led by independent power producers, giving influence to tax-equity perspectives on the choice between the tax credits. The demand for tax equity is expected to grow with the increased incentives in the IRA from approximately $20 billion in 2022 to $50 billion by 2025. Furthermore, because the current pool of financiers has limited spare capacity, a large portion of the incremental demand must be met by new entrants.

The ITC has multiple advantages for tax equity investors, particularly new entrants. First, the timeline is shorter. The tax benefits accrue within five years, the majority of which are realized in the first year. Therefore, an ITC investor needs fewer years of predictable future

Infographic
James Round

Choosing a Tax Credit for Renewable Energy: Investment or Production?

Among the incentives in the Inflation Reduction Act (IRA), corporate tax credits are the largest source of clean energy funding. Two of the biggest credits for solar and wind projects, the investment tax credit and the production tax credit, will produce different outcomes. Here's a brief summary of both credits.

Investment Tax Credit (ITC)

WHAT IT DOES

The ITC provides a tax credit based on the amount invested in setting up clean energy projects like solar or wind power.

HOW IT WORKS

When an investment facilitates a project that generates solar or wind energy, the project gets a tax credit that amounts to a percentage of the total cost.

EXAMPLE

If a clean energy project spends $100,000 on setting up a solar panel system, and the ITC rate is 30%, then the project would get an ITC of $30,000.

DID YOU KNOW?

Before the IRA, solar projects received nearly all ITC funding—the IRA was pivotal in diversifying the beneficiaries of the ITC.

Production Tax Credit (PTC)

WHAT IT DOES

The PTC gives a tax credit based on how much electricity gets produced by a clean energy project.

HOW IT WORKS

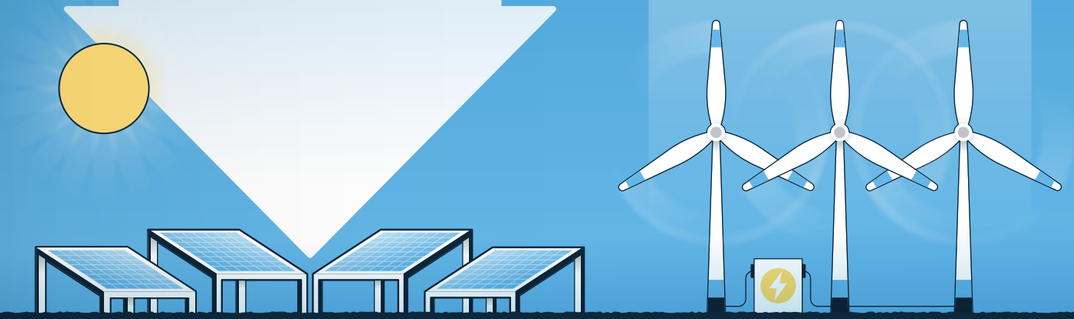
A solar or wind project that generates electricity can get a tax credit for each unit of electricity produced.

EXAMPLE

If a wind farm produces 100,000 kilowatt-hours of electricity, and the PTC rate is 2.75 cents per kilowatt-hour, then the project would get a PTC of $2,750.

DID YOU KNOW?

The PTC subsidizes the quantity of power generation, regardless of the price of power, which incentivizes projects to generate electricity even when prices are negative.



tax liabilities. Second, given that the ITC is based on a project's capital cost, it entails less investment risk than the PTC, which depends on electricity generation over a 10-year period.

For established tax equity investors, these advantages are less significant, and the PTC may even be their preferred structure. The disadvantage of the ITC's short timeline is that investors must make successive investments to offset their tax liability. Because each investment entails a transaction cost, the aggregate transaction costs of ITC investments may favor the 10-year PTC.

Both the ITC and PTC options may help increase the supply of tax equity. The ITC, with its favorable structure for investors who have less predictable tax liabilities, could expand the investor pool in the long term. The PTC—the favored choice of many solar projects that otherwise would have taken the ITC—consumes less tax liability in the early years, thus increasing the near-term supply of tax equity investment.

Regulated Utilities

In regulated markets, utilities are allowed to own power-generation assets, but federal law has limited the appeal of owning ITC projects. Tax normalization rules have required that utilities spread the ITC value over the operating life of the asset, thus diminishing the present value of the credit and increasing the cost of electricity generation.

Rather than own ITC assets, a utility could sign a power purchase agreement with an independent power producer, which is not subject to normalization requirements. However, whereas a regulated utility earns a rate of return on the assets it owns, this is not the case for a power purchase agreement. Indeed, a power purchase agreement is considered a liability on the balance sheet of a utility.

ITC projects thus have been less attractive in regulated markets. Utility ownership is more expensive to ratepayers, and power purchase agreements are unappealing to utilities. In allowing solar projects to elect the PTC, which is not subject to normalization, the IRA removed a disincentive to adding solar capacity in regulated markets.

Economic Distortions Created by Two Tax Credits

Whereas the previous section considered the perspectives of project owners and their market effects, this section focuses on incentive efficiency: how the structures of the ITC and PTC can skew project choices.

The Investment Tax Credit May Increase the Total Cost of Electricity Production

In subsidizing only the capital cost, the ITC can distort how projects weigh capital costs against capacity factors and maintenance costs. Therefore, the ITC has the potential to increase total levelized costs, inclusive of the subsidy cost to the government.

For example, to achieve a higher capacity factor than would be justified without the ITC, renewable energy projects could decide on technology or geography that involves excessive capital costs. A solar project might include equipment that allows panels to track the sun's movements, or renewable projects could choose higher-cost locations that are windier or sunnier.

Additionally, projects could spend inadequate amounts on equipment maintenance. One study on wind projects by Joseph E. Aldy and others finds that projects with an investment subsidy generate 10 percent less electricity than they would have with a production subsidy. Two-thirds of this reduction likely is attributable to projects being less available to generate power, a consequence of reduced maintenance spending.

Post-IRA, cost distortions from the ITC may be modest, as an increasing number of projects choose the PTC. Additionally, solar projects have less equipment risk than wind projects, so reduced power generation from diminished availability is a less significant problem. However, two caveats are important. First, offshore wind has high capital costs, making these projects likely to choose the ITC, and high equipment risk, which increases the availability effect from underspending on maintenance. Second, cost distortions from the ITC are limited by the unsubsidized proportion of capital costs, which is reduced by the bonus credits in the IRA.

> **"Post–Inflation Reduction Act, cost distortions from the investment tax credit may be modest, as an increasing number of projects choose the production tax credit."**

> **"The ability to choose between the investment tax credit and production tax credit will have considerable effects on clean energy deployment, investment supply, and subsidy efficiency."**

The Production Tax Credit May Reduce the Value of Electricity Production

Because the PTC subsidizes the quantity of power generation irrespective of the price of power, the PTC may incentivize lower-value electricity, also known as levelized avoided costs. Note that price of power here refers to the private value of electricity; the social value of electricity also would depend on the emissions profile of the displaced power generation. The PTC can reduce the private value of electricity production by distorting decisions that are made by projects for when to generate and where to locate.

Solar and wind power have zero marginal costs of generation, so projects without a PTC typically produce power whenever the prevailing electricity price is positive. With a PTC, projects may find it profitable to generate power even when prices are negative. The aforementioned wind study found that negative prices likely explain one-third of the difference in electricity generation between projects with production incentives versus investment incentives. Accordingly, utility-scale solar projects that choose the PTC should cause more negatively priced electricity.

Before projects choose when to generate power, they must decide where to locate. In selecting a site, utility-scale solar and wind projects weigh the costs of generation at a given location against the prospective revenues and subsidies (from the ITC or PTC and renewable energy credits). Unlike the ITC, the worth of the PTC varies greatly by location because of the large regional differences in capacity factors. Without a PTC, a project in a high-resource location could be unprofitable if energy and capacity values there are low. However, the same project with a PTC—if curtailment does not significantly reduce output—may be profitable even with minimal revenues.

By incentivizing the quantity of electricity generation rather than the value of the electricity, the PTC may skew projects toward high-resource locations. Because of the constraints on tax equity supply, the PTC may deter the installation of projects in locations where the value-to-cost ratio would be higher.

Increasing the Value of Electricity Production

The likely selection of the PTC accelerates the importance of technology and policy responses to low-value power. Energy storage and flexible demand can help address the time-related components of low electricity prices. Energy storage can transfer a portion of low-value electricity to times when prices are higher, and flexible loads can be moved to be coincident with peak solar generation. To help equalize electricity prices across space, increased transmission capacity is needed. Expanding transmission would require policy changes that address permitting delays in building new transmission lines and that provide incentives for implementing grid-enhancing technologies which increase the capacity of existing lines.

Conclusions

The ability to choose between the ITC and PTC will have considerable effects on clean energy deployment, investment supply, and subsidy efficiency. What explains many of these effects is the higher present value of the PTC for most utility-scale solar and onshore wind projects. Along with its greater value, the preferable treatment of the PTC for regulated utilities will cause additional, widespread growth in solar capacity.

With respect to finance, solar projects that switch to the 10-year PTC will increase the supply of tax equity over the short term. The continuing option of the ITC, with its shorter duration and lower investment risk, could prove important in attracting new investors in the long term. Separately, the IRA allows tax credits to be transferred, which has created a new and remarkably popular option for clean energy finance.

Lastly, cost distortions will diminish, and value distortions will increase, as solar projects shift from the ITC to the PTC. Massive increases in energy storage, flexible demand, and transmission capacity will be required to mitigate the divergence between PTC-induced generation and optimal additions of power to the grid, with supportive policies and permitting reforms playing critical roles. ■

Jay Bartlett is a member of the board of directors and a senior advisor at Resources for the Future.

New solar energy projects can take a long time to be approved, built, and connected to the grid. Some recent federal efforts that aim to accelerate project development have shown mixed results.

TEXT Arthur G. Fraas

The federal government has set the goal of reducing greenhouse gas emissions to 50 percent below 2005 levels by 2030 and achieving net-zero emissions by midcentury. Building a cleaner electric grid—replacing electricity that is generated by fossil fuels with electricity generated by renewable energy sources, like wind and solar—is a vital part of realizing these goals. Building a cleaner grid also will require a lot of construction, which needs to happen quickly to meet the climate goals for 2030 and midcentury.

The build-out of these projects has been slowed by the processes for permitting and approving renewable energy projects to comply with state and federal regulations, which has elevated the discussion of permitting reform to the national stage. Among the various steps, the required review process for compliance with the National Environmental Policy Act (NEPA) has become a key concern. NEPA was signed into law in 1970 and requires federal agencies to evaluate the potential environmental effects of federal projects. In a working paper I published with coauthors last year, we investigated the NEPA review process, with a focus on large solar projects.

Reviewing the Reviews: The National Environmental Policy Act

NEPA was passed during a period of heightened attention on environmental issues in the United States. The law established an environmental review process for federal projects that may have "significant environmental impacts." These types of federal projects are funded, regulated, or organized by the federal government—or they are proposed by a firm or a state, local, or Tribal government and require federal approval or funding. The review process does not apply to fully privately funded projects on private land. NEPA also established the Council on Environmental Quality, which is responsible for implementation of the law across the federal government.

The heart of the review process mandated by NEPA is the environmental impact statement. This statement is completed by a federal agency and serves as a comprehensive study of the environmental effects of a project. Ultimately, environmental impact statements aim to provide information to public officials and the general public; these required statements ensure that the potential consequences of a project receive a hard look. An environmental impact statement includes a description of the proposed project and the affected areas; the reasons the project is necessary; benefits of completing the project; and an analysis of the environmental effects of the project, including adverse effects and any irreversible commitments of natural resources. A statement also must include reasonable alternatives to the project that would have a smaller effect on the environment. Notably, NEPA does not require a particular outcome, nor that an alternative with a potentially smaller effect on the environment will be chosen; the law simply requires the review process.

NEPA can pose a substantial burden for public officials and project developers, given the time and labor involved in conducting an environmental impact statement. The Council on Environmental Quality found in 2020 that, between 2010 and 2018, the average time to complete a statement was 4.5 years, while some major infrastructure projects took longer than 10 years. Lawmakers have pushed to tweak the NEPA review process in recent years to reduce delays in project approvals. Most recently, Congress included a provision in the Fiscal Responsibility Act, a spending bill that became law in June 2023, that directs the Council on Environmental Quality to modify NEPA to streamline the review process. The provision includes page limits on environmental impact statements, along with a two-year time limit on their completion. However, most of the changes to NEPA simply codify current practice that has been established through regulations and court decisions.

Observers expect NEPA to continue receiving attention both from policymakers who want to accelerate the clean energy transition and from others who want to green-light new fossil fuel infrastructure.

The Long Road to Operationality

In a working paper that I published recently with colleagues Andre Bellefontaine, Lindsay Rich Steinmetz, Valkyrie Buffa, and David Storment, we examined the review process of NEPA. We identified 28 solar projects that underwent an environmental impact statement in compliance with federal law, spanning from 2009 to 2021 (Figure 1). We believe that these 28 projects comprise almost all the utility-scale solar projects for which an environmental impact statement was completed over this period. These NEPA projects account for less than 10 percent of the utility-scale solar projects that reached operational status in this period; most solar projects are located on state or private land and don't need to undergo the NEPA review process.

On average, environmental impact statements for the 28 projects took around 2.5 years—over 2 years less than the average time (4.5 years) for all environmental impact statements across all federal agencies. Our working paper shows that two-thirds of the projects completed the formal NEPA review process within 2 years (light blue bars)—a deadline adopted in the Fiscal Responsibility Act of 2023.

However, for more than half of the projects, a total of 7–10 years elapsed between the initial application for development and the

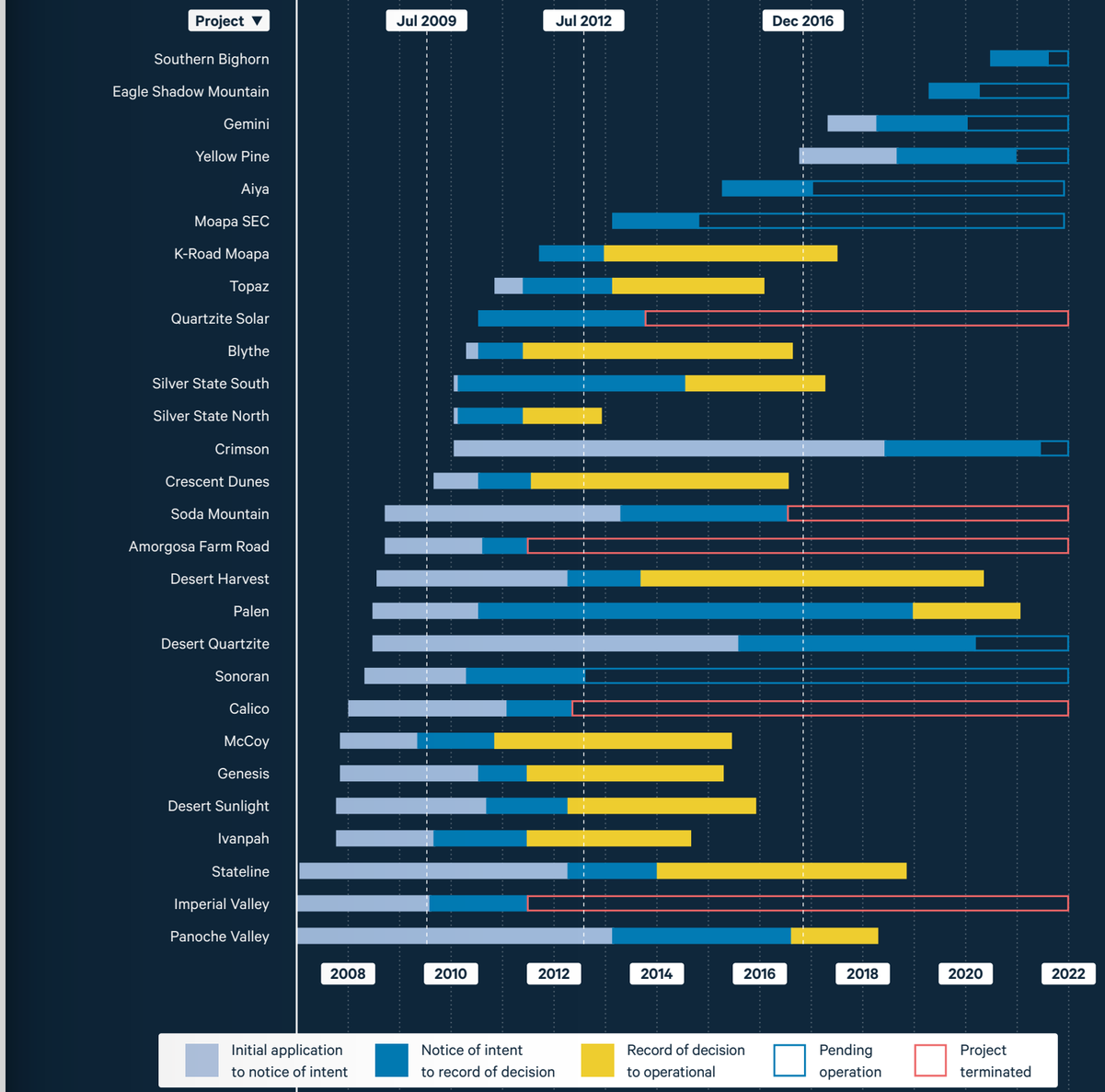
"Observers expect the National Environmental Policy Act to continue receiving attention both from policymakers who want to accelerate the clean energy transition and from others who want to green-light new fossil fuel infrastructure."

Image (previous page)
Pramote Polyamate / Getty Images

Figure 01
A "notice of intent" is a public announcement of a forthcoming review under the National Environmental Policy Act with information about how the public can participate in the process. A "record of decision" explains the decision an agency has made following the review process, any alternatives to the project that the agency considered, and how the agency plans to mitigate and monitor the environmental impacts that may result from a project.

Figure 01

Solar Projects That Completed Environmental Impact Statements Mandated by the National Environmental Policy Act between 2009 and 2021



beginning of operation. The yellow and white bars in Figure 1 indicate delays in reaching operation after the completion of the NEPA review process. Additionally, 5 projects never reached operational status; the red framed bars in Figure 1 indicate these projects.

We also evaluated 18 projects that completed an environmental assessment (a less demanding review process than the environmental impact statement) over the same time period. Of the projects for which we have data, assessments were completed in 1 year or less for one-third of the projects and within 2 years for another one-third of the projects.

A variety of factors contributed to these delays, which often occurred before or after formal NEPA review. The formal NEPA review is sandwiched between the time spent revising a submitted project application and the time when developers engage in the final steps that lead to operationality (building the solar facility, ensuring that the facility meets the permitting requirements, and connecting to the electric grid). The launch of the formal NEPA review process begins with the publication of a notice of intent to prepare an environmental impact statement.

In several cases, formal NEPA review began more than two years after the initial application and involved a preliminary stage of refining and modifying the application. These modifications included shifts from concentrated solar technology to photovoltaic technology, changes in ownership, and reductions to the planned production capacity and acreage of a project in response to concerns raised by federal agencies. The lengthy delays after some formal NEPA reviews also may reflect difficulties that developers encountered in securing agreements to sell power to utilities and connect to the electric grid. Further research would help facilitate a more comprehensive understanding of the reasons for delays that follow NEPA reviews.

Speeding Up Solar Development on Public Lands in the West

Some agencies have more influence than others over the development of renewable energy projects, given the distribution of authority across federal agencies. For example, the US Bureau of Land Management (BLM) is responsible for much of the public land in the western United States and was the lead agency responsible for three-fourths of the environmental impact statements for the solar facilities in our sample.

The BLM received more than 150 applications for solar projects following the passage of a federal law in 2005 that established the goal of siting at least 10,000 megawatts on public lands by 2015. In response, the US Department of the Interior and the BLM have implemented several initiatives to try to expedite the review of applications for these leases. But available data indicate that the initiatives have had limited success, and developers continue to report delays in the BLM's approval of leases.

The Western Solar Plan, which launched in 2012, was one of the agency's major initiatives. The BLM identified 19 sections of public land in 6 southwestern states as suitable for solar projects. The agency determined that solar projects in these areas, known as solar energy zones, would be easy to connect to transmission lines for transporting electricity and have limited adverse social and environmental effects.

Implementation of the Western Solar Plan has proven to be complicated. The BLM took another four years to complete policy actions related to the plan, and the change in administration in 2017 resulted in further delays to the approval of new solar facilities. Under the Trump administration, the BLM reviewed past policy decisions about the broader use of public lands in the Southwest and issues that were specific to solar development in the region. By December 2021, only two solar facilities were approved and operating in solar energy zones under the provisions of the plan.

The intent of the Western Solar Plan was for the agency to streamline the NEPA review process for individual solar projects by tying their approvals to prior NEPA reviews of earlier steps in the leasing process, such as the creation of broader land use plans and the designation of solar energy zones. However, additional measures, terms, and conditions to reduce potential environmental impacts could be identified through a final confirmation process, and the implementation of these measures would be required before the BLM allows the project to proceed.

Further, this approach has been vulnerable to delays that occur when the BLM carries out the procedures required for leasing parcels in the solar energy zones. Steps in this leasing process include completing necessary studies and evaluating the site, soliciting interest in parcels, providing notice about and conducting a competitive bidding process for the lease, and confirming that the selected developer's plan aligns with the preapproved parameters for the use of the parcel. Notably, the BLM has discretion over the timing of these steps.

Observations and Considerations for Future Policy

Our review of the first 10 years of the Western Solar Plan has yielded several observations and considerations for solar permitting, perhaps suggesting some best practices for future policies.

First, the implementation of the plan involves several key steps. The delay associated with these steps has slowed the development of solar projects in the solar energy zones. Given the flexibility and discretion that are embedded in the leasing process for public lands, siting solar facilities on public lands probably won't get significantly faster, even with the presumptive deadlines for formal NEPA reviews in the Fiscal Responsibility Act.

Second, interest has been limited in the land that lies in the original solar energy zones. Apart from some of the parcels in Nevada, parcels of land in these zones have received no bids or low bids from developers. Whether the agency's selection of land reflects the most attractive locations for solar projects from the perspective of developers remains unclear. However, developers have proposed and received approval for projects outside solar energy zones in these southwestern states. If the BLM wants to promote project development on public lands, then the agency should consider facilitating more projects in areas outside solar energy zones.

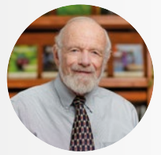
Finally, the size of several solar energy zones is enough to accommodate only a single utility-scale solar project. Significant resources and time are required to designate an area as suitable for renewable energy development, and to take the additional steps to make the land available for auction. If the BLM wants to expand the areas that are designated as suitable for renewable energy development, then the agency should prioritize larger areas that could accommodate multiple utility-scale projects.

Looking Forward

The nation already may be behind schedule for reducing emissions from the power sector, compared to what analysts projected when the Inflation Reduction Act became law in 2022. Accelerating the development of solar energy facilities and other clean energy projects is imperative if the nation wants to meet US goals for reducing emissions. If policymakers want to speed up the energy transition, then NEPA reviews and other permitting processes deserve a careful look. ■

> **Accelerating the development of solar energy facilities and other clean energy projects is imperative if the nation wants to meet US goals for reducing emissions.**

Photo (left)
prostooleh / Getty Images



Arthur G. Fraas is a visiting fellow at Resources for the Future.

#MyResources

Food for Thought!

TEXT Emma DeAngeli

At Resources for the Future, we love breaking new ground when it comes to energy research—and we recognize the importance of unplugging from technology to replenish our mental batteries. The garden team *literally* breaks new ground to create our own fuel with the most original of energy inputs: the sun! Our rooftop garden provides an avenue for us to attentively nurture plants; share memories with colleagues (see the gigantic sweet potatoes); and, of course, reap the fruits of our labor. Much like our research, the garden would not function without its team of passionate individuals who deliberately work toward a common goal. And, in this case with our garden, we know that delicious snacks are guaranteed.

Photos *Courtesy of the rooftop garden crew at Resources for the Future*

Illustrations *Northern Owl / Getty Images*

Crossed Wires: Modernizing the US Electric Grid

TEXT
Richard Schmalensee

ILLUSTRATION
Andrea De Santis

The Biden administration aspires to eliminate all carbon emissions from electric power production by 2035, mainly by substituting wind and solar for coal and natural gas. And that's just the beginning: By substituting clean electricity for fossil fuels throughout the economy, the US government aims to achieve net-zero carbon emissions by midcentury—meaning that enough carbon dioxide will be removed from the atmosphere to offset any remaining emissions from human activity. Give the president credit for audacity. The Biden administration seeks to transform the massive, capital-intensive electric power sector in a little over a decade and to reshape all US energy use in less than three. But this is not mission impossible: it's technically feasible, even on that ambitious timeline.

One major hurdle, though, could prove a deal-breaker. Increasing the role of electricity in transportation, heating buildings, and myriad other uses will increase electricity demand more rapidly than the overall rate of economic growth—which will require a disproportionate expansion of high-voltage transmission capacity. Indeed, a slew of studies agree that achieving net-zero emissions efficiently by 2050 will depend on increasing transmission capacity by at least 150 percent and perhaps by as much as 400 percent in less than three decades.

Although annual investment in US transmission roughly quadrupled from less than $5 billion before 2005 to as much as $25 billion since 2013, the sorts of investments in transmission that are needed to decarbonize the US electric power system at reasonable cost are substantially different from most of those made in the recent past. And these investments face more serious obstacles.

Without fundamental reforms in planning and permitting, investments in cost-effective transmission can't possibly keep up. Rapid economy-wide decarbonization still may be technically feasible, but the price tag probably would be politically unacceptable.

The Changing Role of Transmission

The Past

Shifting from fossil fuel power generation to wind and solar power generation will require significant expansion of the transmission system to connect wind and solar generators to the system, typically in areas that don't have much preexisting transmission capacity. In the jargon of the business, this integration of power generators in the electric grid is called "interconnection."

Historically, electric power was provided by regulated utilities or government enterprises, the only power providers in well-defined service territories. Each utility typically generated all the electricity in its service territory mainly by burning fossil fuels, delivering the power to customers over the high-voltage transmission lines and low-voltage distribution lines that it owned. The most efficient approach was to locate generators near the major demand centers.

In the 1960s and 1970s, transmission lines were built to link adjacent utilities, make electricity more reliable, and bring power from hydroelectric generators to demand centers. Regulating electric utilities was the job of state governments almost exclusively; long-distance, interregional transmission of electricity was rare.

Beginning in the late 1990s, electric power systems in many parts of the country were restructured. Power generation was decoupled from transmission, and organized wholesale markets for electricity were established.

Seven nonprofit independent system operators (ISOs) have been established over time to manage transmission systems and supervise organized wholesale markets that meet about two-thirds of the nation's electricity demand. The ISO that serves most of Texas, called the Electric Reliability Council of Texas (ERCOT), has only weak interconnections with the rest of the nation for political reasons; accordingly, the Federal Energy Regulatory Commission (FERC) has authority over all transmission systems other than ERCOT.

To encourage competition among generation companies in wholesale electricity markets, FERC issued Order 888 in 1996. This regulation requires transmission operators to allow all generators to connect to ISO systems on nondiscriminatory terms. But new generators are required to fund new lines and reinforcements to existing lines for reliability purposes. So long as the need for new connections was limited to a relatively small number of fossil fuel–powered generators near demand centers, this process was relatively smooth.

The Present

Everything changed at the turn of this century. Investment grew in wind and solar power generation, thanks to a combination of federal subsidies, new mandates in many states for wind and solar energy, and dramatic declines in the cost of wind and solar power generation. Old fossil fuel–powered generators, particularly the large coal-fired plants that had dominated production for decades, began to retire.

This rise in wind and solar power complicated the interconnection process in two ways. First, utility-scale wind and solar power generators require lots of space and thus are located far from where demand is concentrated. But rural areas don't have much preexisting transmission capacity; connecting a new wind or solar generator in remote places often requires expensive upgrades to the transmission system. Moreover, connecting offshore wind generators involves building completely new undersea transmission networks and reinforcing the onshore transmission system.

Second, utility-scale wind and solar generators tend to produce less electricity than the fossil fuel–powered generators they've replaced. As a result, the number of connections between generators and transmission systems has needed to increase to deliver the same amount of power. In 2022, for instance, 614 new, relatively small generators replaced 166 retired utility-scale generators, though total generating capacity stayed essentially the same.

For the transmission system to facilitate decarbonization at reasonable cost, the system must be able to span long distances. The quality of wind and power resources varies substantially

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from region to region, with the cost of solar generation lowest in the southwestern United States and the cost of wind generation lowest in the middle of the country. Moreover, because regional shifts in cloud cover and wind can rapidly change geographic patterns in the availability of solar and wind power, interregional connections can enhance overall reliability, increase the supply of energy, and reduce the average cost of power. Consequently, long-distance transmission of electricity (particularly interstate) has much greater value in systems that are dominated by solar and wind energy, compared to systems that run primarily on fossil fuels. Planning investments in long-distance transmission at the national level will be necessary for an efficient, reliable national grid; however, no government entity has responsibility or authority for national-level transmission planning.

Despite their growing importance, new long-distance transmission lines are becoming increasingly rare. The installation of very high-voltage transmission lines (above 345,000 volts, suitable for moving power efficiently across hundreds of miles) declined from 1,700 miles per year in the first half of the 2010s to an average 645 miles per year in the second half of that decade. Only 567 miles were completed in 2021, and only 198 miles were constructed in 2022.

Throughout the country, long and growing queues await connection to the transmission system for projects related to wind power, solar power, and related energy storage. By the end of 2022, about 10,000 projects had applied for connection to the transmission grid.

The Interconnection Problem

Under FERC Order 845, issued in 2018, utility-scale generation and storage facilities that seek to connect to the transmission grid must make an interconnection request to the relevant transmission operator, which in much of the country will be an ISO. Facilities get added to the queue in the order in which they apply. After a sequence of studies, each facility applicant is told what it must pay to be connected. If an applicant agrees to accept the final assessed cost, an interconnection agreement is signed, and the transmission upgrade can go forward.

Connecting generation capacity at one point may require upgrades to relatively distant transmission lines. So, the process of assessing any particular project's interconnection costs can be quite complex—and easily disputed.

Applicants can withdraw from this process at any time and at little cost. So, a project developer has strong incentives to submit multiple interconnection requests for different interconnection points as early as possible. Applicants can simply walk away for any reason.

Between 2014 and 2022, interconnection requests nationwide increased by a factor of four in terms of generating capacity. At the end of 2022, the total proposed capacity of projects with active interconnection requests represented 163 percent of the capacity of the entire US power system! Most of those proposed projects will never get built. Of the requests made in 2000–2017, only 14 percent (in terms of capacity) were completed by the end of 2022, in large part because most project applications were withdrawn. Fully 71 percent of the interconnection requests made in 2014–2017 were withdrawn by the end of 2022.

These withdrawals slow everything down. When one project's interconnection request is withdrawn, the costs of connecting the projects that follow in the queue typically need to be reexamined. Numerous withdrawals in recent years, along with a scarcity of staff that have the relevant expertise, have contributed to increases the median time between interconnection request and interconnection agreement from less than 20 months in 2015 to around 35 months in 2022.

Recent Response from the Federal Energy Regulatory Commission

Under FERC Order 2023, adopted in July last year, eligibility for an interconnection agreement requires a developer to already have the right to build on the site it proposes to use and to post a deposit. Developers then may apply to be included in a cluster of projects that get studied together, with the aim of reducing repetitive reevaluations of costs. Order 2023 also provides general rules for the allocation of interconnection costs among members of a cluster. Transmission providers are obligated to show developers where interconnection capacity is available without major upgrades to the system, and the providers must meet strict deadlines for study completion.

Nationwide implementation of Order 2023 likely will shrink the queues of interconnection requests. But this policy ensures that the interconnection process will remain purely reactive and incremental, making it a poor vehicle for efficient expansion of the nation's transmission system. Moreover, transmission providers that have adopted many of the reforms in Order 2023 nonetheless still have long queues.

Alternative Approach to Interconnection

A better way is possible. An alternative, proactive process was applied in the highly successful Competitive Renewable Energy Zones (CREZ) transmission project in Texas.

In 2002, the Texas legislature ordered the Public Utility Commission of Texas to plan and supervise the construction of transmission lines to meet growing electricity demand by enabling dramatic increases in wind generation. The costs of the new lines were borne collectively by all Texas ratepayers. The Public Utility Commission of Texas identified a small number of "renewable energy zones" in rural areas with good wind resources, plenty of cheap land, and developer interest in building wind farms. By March 2009, regulators decided on the new high-voltage transmission lines and designated the builders, with technical support from ERCOT and with input from stakeholders. The new lines went into service rapidly, by January 2014, which dramatically reduced the interconnection costs for wind generators.

These CREZ lines constituted 23 percent of all the high-voltage lines built in the United States in 2008–2020 and involved proactive regional transmission planning in advance of specific generation proposals. Wind-generation capacity in Texas increased by a factor of 12 in 2005–2020, with much of that new capacity built after the CREZ lines were in service. The process was greatly simplified by the decision to distribute the costs of the new

high-voltage lines across all Texas ratepayers and by granting authority to a single agency (the Public Utility Commission of Texas) with the power of eminent domain.

Other ISOs have begun to follow this model of planning the expansion of transmission lines to accommodate the new power generation that's expected.

The Long-Distance Problem

The SunZia Wind and Transmission Project illustrates the magnitude of the problems related to planning and permitting that stand in the way of building critical long-distance transmission lines.

In 2006, SunZia was proposed as a stand-alone "merchant" transmission project, meaning that it was conceived as an unregulated project without a guaranteed return on developer investment. In May 2023, the project received final federal approval for construction to begin. Construction began on September 1, but work on a 50-mile segment was suspended in early November in response to complaints by Native nations in Arizona. When SunZia ultimately becomes operational, it will be the largest wind project in the Western Hemisphere, with 550 miles of high-voltage transmission lines that will connect wind-generating rural counties in New Mexico to demand centers in Arizona.

Perhaps SunZia would have emerged from a comprehensive regional planning process—but probably not. A set of stand-alone projects, each designed to be economically viable and to elicit the necessary political support, is unlikely to add up to an efficient regional system. Interregional negotiations are even more complex, and successful negotiations are quite rare. Whereas FERC can compel planning—and it has done so with Order 890 in 2007 and Order 1000 in 2011—the agency cannot compel agreement within a reasonable time. And without agreement, nothing gets built.

Compounding these problems is the multiplicity of FERC-defined regions for transmission planning, each of which is responsible primarily for intraregional transmission. The contiguous United States contains 12 such regions: the seven ISOs mentioned above and five other regions, mainly in the West and Southeast, that lack an ISO responsible for managing the regional transmission system. The boundaries of these 12 regions generally do not coincide with state lines, several regions are not contiguous, and state governments generally are not involved in transmission planning. An efficient nationwide system with appropriate long-distance interstate transmission is unlikely to result from such a geographically fragmented system that's focused almost exclusively on intraregional transmission.

In 2005, a prescient US Congress attempted to bulldoze the barriers of this decentralized approach by empowering the US Department of Energy to designate National Interest Electric Transmission Corridors. If a state failed to approve a proposed transmission project in one of these corridors in a timely fashion, FERC would have the authority to coopt the project. But the courts effectively gutted this authority, which has been moribund since 2011. In 2021, the law was amended to give FERC siting authority for corridor projects that had been rejected by one or more states. The Department of Energy and FERC currently are developing rules that will govern this newly revived process. This project-by-project siting authority may enable some beneficial projects to go forward that otherwise would be blocked. But this backstop law is no substitute for systematic nationwide planning and siting.

The contrast between the system in the United States and the system in the European Union is dramatic. In the European Union, an expert agency called the European Network of Transmission System Operators for Electricity prepares development plans that span 10-year periods and the entire European Union. The agency has the authority to accelerate important projects that cross national borders.

The permitting problem for long-distance projects like SunZia may be at least as important and difficult to solve as the problem of planning an efficient national

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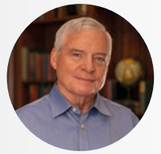


Richard Schmalensee is chair emeritus of the board of directors at Resources for the Future, a professor emeritus of economics and management, and former dean of the Sloan School of Management at the Massachusetts Institute of Technology. A version of this *Resources* magazine article was first published in the *Milken Institute Review*.

transmission system. Getting the permits to allow SunZia to begin construction in 2023 reportedly required 17 years and involved 10 federal agencies, 5 state agencies, and 9 local authorities. Moreover, the route of the transmission lines was changed many times in response to local, state, and national stakeholders, becoming circuitous in the process. The implications are ominous: if a long-distance transmission line proposed in 2023 could not even begin construction until 2040, then decarbonization will happen much too late for the United States to reach its midcentury goal.

Another source of long delays is lawsuits that charge environmental violations. The issue is not whether the lawsuits filed against any project have merit; serious claims that a project violates environmental laws deserve their day in court or before a federal regulator. The problem is that the current permitting regime does not require all such claims to be presented and evaluated within a reasonable time frame. Unless resolving challenges to major infrastructure projects becomes possible in a timely fashion, the United States may not be able to build the transmission grid that's necessary before midcentury.

Policy Solutions for the Long-Distance Problem

The US Congress took a small step toward solving the permitting problem with the Fiscal Responsibility Act of 2023, which sought to streamline and place time limits on project reviews under the National Environmental Protection Act. But even if these reforms are effective, infrastructure projects will remain vulnerable to long delays caused by lawsuits that are based on other environmental statutes.

The Biden administration seems to recognize the need for broader permitting reform. In May last year, the White House announced a plan to coordinate transmission-line permitting among six cabinet-level departments and three other agencies, with the Department of Energy designated as the lead agency for environmental review. Such coordination could prove especially valuable in the western United States, where federal land use largely is at issue. Days later, the White House posted a long list of priorities for permitting reform. These priorities would be a fine point of departure for legislation.

FERC's recently reinvigorated backstop siting authority, which works on a project-by-project basis, is no substitute for an expert planning agency with nationwide scope. The ongoing National Transmission Planning Study, overseen by the Department of Energy, covers the entire contiguous United States and could be the seed for such an agency.

Uncrossing the Wires

While FERC's recent Order 2023 may help shorten interconnection queues and reduce the repetitive reevaluation of proposed interconnections, the approach remains fundamentally reactive and incremental. As a result, costs will be higher than they could be if transmission providers would follow the CREZ model and proactively build high-capacity lines that can integrate wind and solar power generation. Several ISOs are moving in this direction. Another helpful move would be for FERC to require all regional transmission managers to follow suit.

Business as usual clearly cannot produce an efficient national transmission system; comprehensive interregional planning is necessary. But despite FERC's initiatives, such planning is rare, and plans that cover more than one FERC region do not exist. As in the European Union, a single agency with the power and responsibility to get the job done would help—and would require a substantial concentration of authority. Even with such an agency, the permitting delays for long-distance interregional transmission lines would remain a formidable barrier.

With sufficient political will, the US power sector can decarbonize by 2035, and the United States can reach net-zero emissions by midcentury. But without a fresh and comprehensive approach to planning and permitting, the cost of reaching these goals will be much higher than necessary—and the political barriers accordingly will be more daunting. ■

NO. 215 | SPRING 2024 | *"Large-scale, long-term transmission planning can come with trade-offs."*

Long-Term Transmission Planning? Be Careful

Economy-wide decarbonization requires large-scale decarbonization of the electricity sector. Hence, large-scale advance planning to expand transmission capacity and boost renewable power sources may be needed. But let's look at trade-offs to be navigated.

TEXT
Tim Brennan

PHOTO
igorbondarenko / Getty Images

Radically reducing carbon dioxide emissions is imperative for limiting future harms from global warming. Global decarbonization will require a rapid and vast expansion of solar power and wind power. Since solar and wind power generators have to be built where the sun shines and the wind blows, building up renewable energy resources will necessitate an equally rapid and vast expansion of transmission lines to bring this electricity to the places where people use it.

To address this need for expansion, regulators and many decarbonization advocates have proposed replacing the currently incremental, request-based method with a different process for expanding transmission through large-scale, long-term planning. The potential downside is that this kind of planning could adversely affect competition in electricity generation. The benefits of that competition—namely, cost-based pricing and fostering entrepreneurship through independent choices—have justified policies for more than three decades that bring competition to wholesale generation. Proposals to introduce collective planning may sacrifice these benefits that competition brings. Large-scale, long-term transmission planning can come with trade-offs.

The costs of limiting competition among power generators may be mitigated within the transmission-planning policy itself. For instance, long-term planning should be flexible enough to vary plans as market conditions warrant. Public research funding may be needed to make up for any attenuated incentives. Decisionmakers must recognize that the longer the planning horizon, the more likely are expensive and politically controversial mistakes. And ensuring buy-in from all affected parties may require effective carbon pricing, so the monetized benefits of decarbonization can cover the costs of expanding transmission.

Why Might Policy Intervention Be Necessary?

Simple economics suggests that new transmission lines presumably would be built if the benefits of adding a line or expanding the capacity of current lines exceed the costs of doing so. If such lines are not being built, then something must be standing in the way.

A first step in understanding the need for transmission policies and how to design them is to see if the historical record supports claims that something prevented the construction of beneficial lines. In its justification for Order 1000 in 2011, the most recent major prior foray into investment policy for national transmission, the Federal Energy Regulatory Commission (FERC) found that "the narrow focus of current planning requirements and shortcomings of current cost-allocation practices create an environment that fails to promote the more efficient and cost-effective development of new transmission facilities," a claim much like the arguments made today in favor of proactive national transmission planning.

At that time, FERC did not provide much of a record of failure. The agency included no examples of transmission lines for which the expected benefit exceeded the expected cost but were not built. FERC gave no examples of lines that were thwarted by failures of planning, lack of information sharing, or inability to allocate costs on the basis of benefits, even stating that "the remedy we adopt is justified sufficiently by the 'theoretical threat' identified herein, even without 'record evidence of abuse.'" More recently, a 2020 US Department of Energy study of transmission congestion reported that transmission investment in the part of the continental United States that's under FERC jurisdiction (roughly, everything but Texas) was about six times greater in 2018 than 20 years earlier.

The functional separation of electricity transmission from electricity generation, which FERC had adopted to promote competition, may make it harder to coordinate the expansion of both. If little growth in demand were expected for the future, this need for coordination may not have been consequential. However, because of the ambitious goals for decarbonization that have been set for midcentury, the large-scale construction of new wind and solar generators will require an expansion of the transmission grid. But what are the downsides to long-term planning as an approach to meeting those goals?

Conflicts with Competition

The degree of transmission planning that's envisioned by many as necessary to decarbonize the US economy poses challenges to the decades-long effort to expand the scope of competition in the electricity sector.

For over 25 years, a primary objective of national energy policy has been to promote competition among power generators, largely by inhibiting their control of access to the transmission lines that are necessary for competition. The recent proposals for collectively planning future transmission are in tension with this view. To put it bluntly: in other settings, sellers that share plans for future electricity capacity and output likely would count as committing an antitrust violation.

However, competition manifests in other ways and hence poses another source of tension with long-term transmission planning. Competition rewards entrepreneurs for finding and acting on private information to discover new markets, reduce costs, and deploy innovative technologies. In that conception, the opposite of competition is not monopoly; monopolists also can discover these rewards. Rather, the opposite is collective planning, which attenuates or removes the ability and incentive to exploit private information to pursue new technologies and market opportunities.

For all its defects, the current incremental process of obtaining transmission capacity has the virtue of allowing transmission lines to adapt to new developments in the market. This evolution of the market can include differential rates of technological change that increase the relative advantages of solar generation, wind generation, carbon capture and storage, and energy efficiency. Climate change itself may affect relevant costs, such as fire-related risks. Climate change mitigation or adaptation policies can make previously unprofitable transmission lines profitable, and increased energy efficiency at the consumer end could have the reverse effect. Broad-scale planning may preclude the evolution of market responses that may, and to some extent hopefully will be, likely as we learn more about how best to undertake massive decarbonization of the US economy.

Policy Responses

If the United States ends up implementing long-term, anticipatory transmission planning, some particular policy responses may be helpful.

Antitrust immunity

Antitrust enforcement may discourage information sharing and output commitments by competitors. Explicit statutory immunity may be warranted.

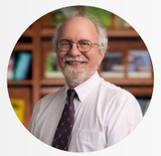
Innovation support

Loss of opportunities to profit from independent entrepreneurial initiatives reduces the incentives to innovate. Policy options can compensate for these reduced incentives by increasing public funding of research and development in non-emitting electricity generation, carbon capture and storage, improved batteries, and other technologies.

Further Reading ...

A version of this *Resources* magazine article was first published by Resources for the Future as a working paper called "Is Transmission Expansion for Decarbonization Compatible with Generation Competition?"

> **"Decarbonization may drive new electricity transmission, but until public policy to mitigate climate change becomes much firmer, decarbonization goals introduce policy risks that may keep new transmission lines from being built."**



Tim Brennan is a senior fellow at Resources for the Future.

Limit the planning horizon

The longer the time horizon, the more information may be lost that otherwise might have accrued after plans are put in place. To reduce these costs, regulators can consider reducing the planning horizon, for instance by allowing the review of original plans and the implementation of revised plans over shorter periods.

Allow independent variation

Policies may be able to include a process by which power generators that perceive new market opportunities remain able to exploit those opportunities by requesting transmission lines outside the long-term planning process.

Accept inevitable error

Mistakes are likely with long-term planning that does not allow the use of private information as it may develop over time. Technological change in electricity generation, for example, may mean that transmission lines that were planned at one time turn out to be used much less than envisioned, especially lines that connect to locations outside of any loops that would carry electricity between other locations. If estimates are correct that, over the next several decades, the United States might spend upwards of a trillion dollars on increased transmission capacity, then getting that investment 90 percent right still would mean that $100 billion is spent on lines that look wasted in hindsight. Everyone involved should expect such errors and be prepared to justify their costs (borne inevitably by ratepayers or taxpayers) by citing the overall net benefits of collective planning.

We Still Need Carbon Pricing

Demand for renewable electricity generation, and thus the planned construction of transmission lines to serve that demand, depends on the fossil fuel alternatives becoming relatively more expensive, be they natural gas generators or internal combustion–powered automobiles. Decarbonization may drive new electricity transmission, but until public policy to mitigate climate change becomes much firmer, decarbonization goals introduce policy risks that may keep new transmission lines from being built which otherwise would be profitable, were the country committed to reducing carbon emissions.

Making carbon pricing explicit is important to facilitate cooperation across all parties that may be affected by a planned expansion of the transmission system. Sufficiently wide public acceptance of an expansion will require that costs which are allocated to a particular state or region are sufficiently below the benefits that expanded transmission will bring to that area. National or global benefits from decarbonization do not accrue to the residents of states along a transmission route; rather, the benefits accrue elsewhere in the country and around the globe. The failure to implement a price on carbon precludes a bargain in which those who view a transmission line as costly can be compensated solely out of the benefits that accrue to residents who would benefit from increased access to renewable power. Renewable energy sources need to be able to charge a price that reflects their competitive advantage over fossil fuel generators, which would have to pay this carbon cost. Carbon pricing provides the appropriate incentives to build renewable energy resources, pay for new transmission lines, and compensate the customers who otherwise would not want to incur the costs.

Conclusion

The benefits of decarbonization may well justify replacing incremental expansions of the transmission system at the request of particular power generators with an alternative approach of long-term collective planning in anticipation of future transmission needs. Policymakers who are charged with such long-term planning should recognize the potential loss of static competition on price and quantity, the potential loss of dynamic competition from entrepreneurial investment and innovation as technologies and market opportunities evolve over time, the likely substantial cost of error, and the continued need for some form of carbon pricing. ■

What to Watch ... ... in the Year Ahead

What's coming up for energy and the environment in this major election year? Here's a digest of the headline topics that speakers at Resources for the Future have discussed recently.

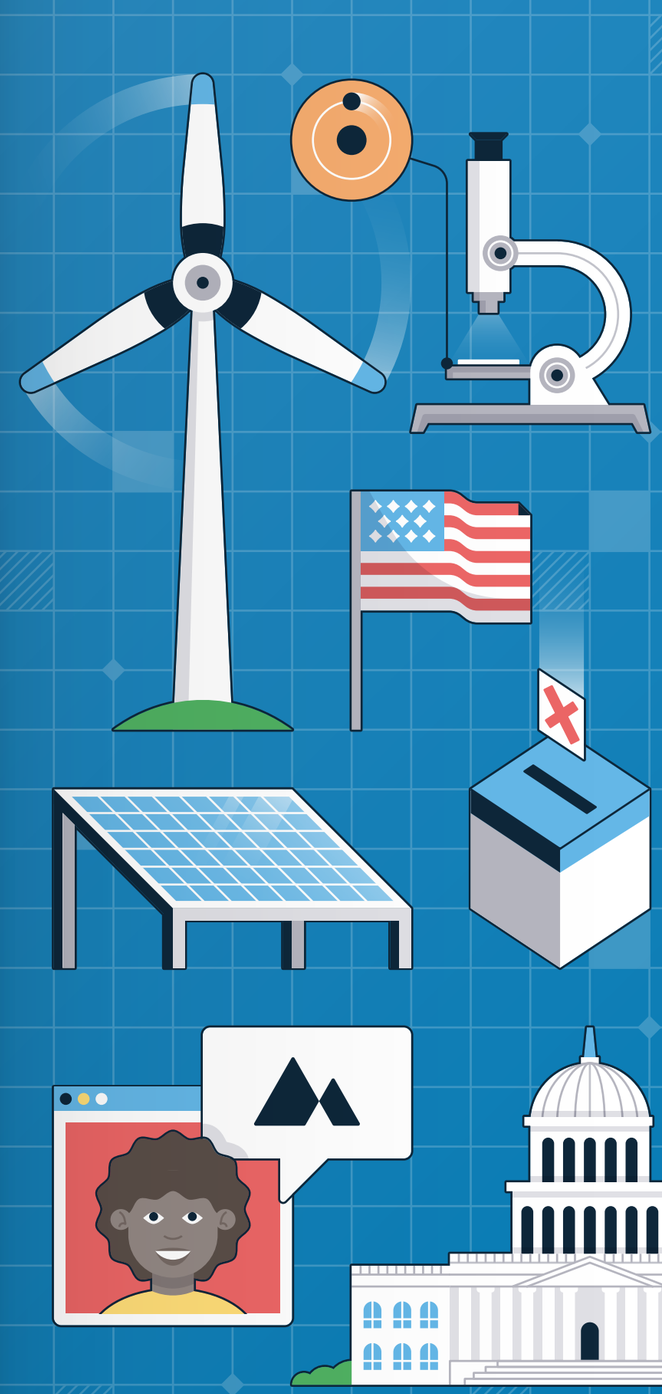
TEXT
Elizabeth Wason

ILLUSTRATIONS
James Round

Resources for the Future (RFF) stays on top of the most important developments in energy, the environment, and natural resources, particularly in the climate policy space.

RFF's ongoing events and weekly podcast help bring perspectives together on these topics; this article shares insights from seven experts who have visited RFF's venues to discuss what developments they're watching this year. With 2024 being the fourth year of the Biden administration and a presidential election year, the stakes are high for policy planning and strategies in 2024 and beyond.

So, what's coming up for energy and the environment? Here's a digest of the headline topics that speakers at RFF have discussed recently.



The experts quoted in this article include:

Vicki Arroyo
Associate Administrator for Policy at the US Environmental Protection Agency

Lisa Heinzerling
Professor at Georgetown University

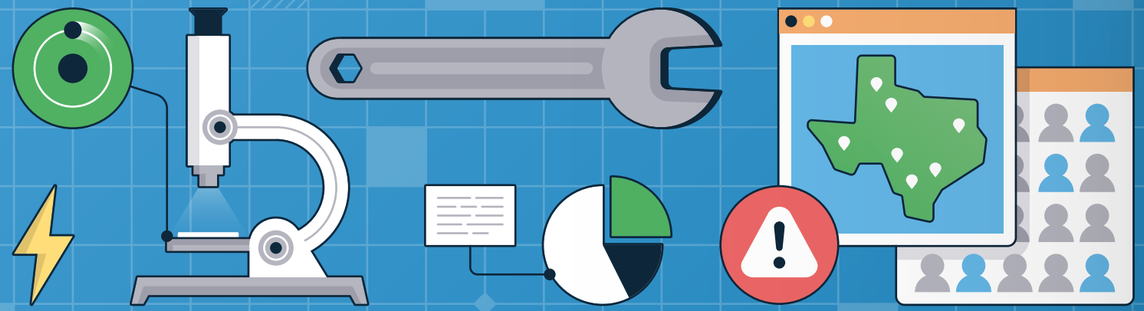
Joseph Majkut
Director of the Energy Security and Climate Change Program at the Center for Strategic and International Studies

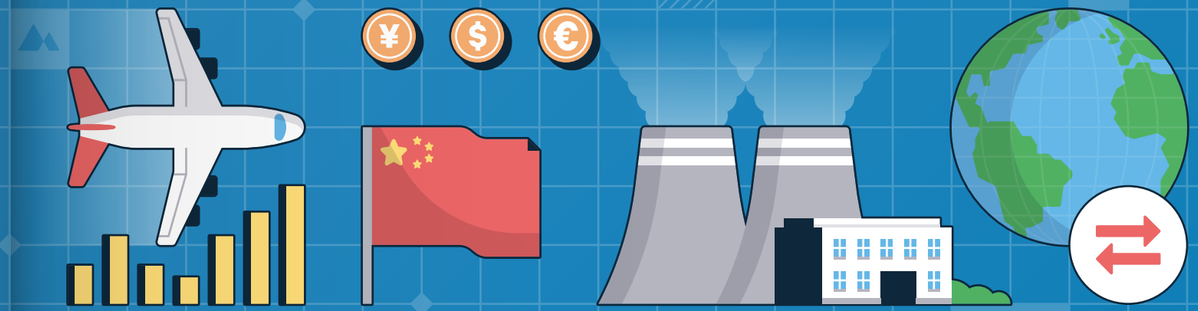
Robinson Meyer
Founding executive editor of Heatmap and a contributing opinion writer for the *New York Times*

Karen Palmer
Senior fellow at RFF and director of RFF's Electric Power Program

Rich Powell
CEO of Clean Energy Buyers Alliance
Former CEO of ClearPath and ClearPath Action

Kevin Rennert
Fellow at RFF and director of RFF's Federal Climate Policy Initiative





Inflation Reduction Act-ivity

Implementation

Joseph Majkut: Over the next year, I'll spend a lot of time looking at the implications for US energy policy of a successful Inflation Reduction Act.

Making a lot of stuff requires a lot of energy. We want to move manufacturing back into the United States, where we want to be at the technological frontier for microchips, clean energy goods, and pharmaceuticals. It'll be interesting to see how much this renaissance of manufacturing will change our energy forecasts, our energy needs, our plans for decarbonization, and fundamental energy reliability.

Take the case of Texas from the last couple years: Because of its population trends and economic growth, the power system there has gotten strained. It's failed at different times and is still at fairly high risk. This situation may become the story for a lot of the United States, and I think that'll be an important thing to watch: How do we meet the needs of this renaissance on the energy side while still achieving climate goals?

Robinson Meyer: I think one of the biggest questions this year—something we don't know the answer to yet—is whether the money that is getting spent from the Inflation Reduction Act and the Bipartisan Infrastructure Law is starting to affect the lives of voters. I think the big questions I have around these two laws this year are: Will they spend enough money to be electorally significant in November? But even more importantly, will they spend enough money to create any durability around these two laws? And finally, what is all that money actually doing?

Rich Powell: The most important of all the existing clean energy tax credits, from the perspective of carbon impact, is the one that folks have talked about the least in the past 12 months. I'm referring to the new tax-credit structure—the 45Y and 48E credits, which are zero-emissions credits on both the production credit side and the investment credit side, which RFF's climate models have provided insights about.

All the models from RFF and others show that these are the most consequential of all the credits. Yet, because these credits aren't in effect until next year, they've had the least constituency pushing for the guidance to come out. I think there's going to be a massive amount of focus on these credits, and some really big decisions have to be made around implementation that will drive their consequences.

Hydrogen

Rich Powell: The US Department of the Treasury has made its first proposed set of rules on the implementation of the 45V credit—the Clean Hydrogen Production Tax Credit—one of the most bipartisan and broadly supported of all the credits. And one that's also been quite contentious. A lot of follow-on facts will arise for how the administration decides to incorporate the mountain of feedback that it's now receiving about that proposed rule and to implement the final rule. I think that decision will shape the degree to which 45V is both a broadly used and broadly supported credit going forward.

This tax credit is significantly open to litigation risk because of some of the very assertive interpretations of the statute that were taken in its crafting. I'm particularly talking about whether existing nuclear plants can take advantage of the credit in the way that the statute explicitly says they can: a requirement was added in the Treasury guidance for additionality, which means that existing nuclear plants cannot take advantage of the 45V credit. For example, the Infrastructure Investment and Jobs Act modernized hydrogen research, development, and demonstration programs at the US Department of Energy. The act also appropriated $9.5 billion to commercialize hydrogen production and create foundational regional clean hydrogen hubs, including four that would use nuclear energy for hydrogen production. The tax credit was meant to complement the policies in the Infrastructure Investment and Jobs Act and boost the efficacy of the hydrogen hubs.

The Treasury Department runs the risk of squandering nearly $50 billion in hydrogen investments across the seven hydrogen hubs and stalling the deployment of clean energy that's necessary to meet demand for energy in the industrial and power sectors. If 45V guidance is improved and follows the intent of Congress, we could see a rapid acceleration of clean hydrogen production and progress toward a low-carbon future, especially as energy is produced through clean assets like nuclear and hydropower.

International Trade and Competition

Joseph Majkut: Right now, the United States and China are in a new era of geopolitical competition. Technologies like battery-manufacturing facilities for electric vehicles and solar panels are viewed on both sides of the Pacific Ocean as strategic and important for both climate goals and long-term energy security. The United States is facing deep questions about how much we want to integrate US supply chains with technology from Chinese firms, which often are backed by the state, but often are better than what US firms can produce; for instance, cheaper, more reliable, higher-capacity batteries.

One of the things we've seen over the past few years is a rising trend of resource-rich countries—Indonesia is the highlight example—expressing a new resource nationalism. They're saying that they don't want to be just an extraction hub and sell raw ore to processors and manufacturers abroad; instead, they want to move up the supply chain of value to their own country. The whole world is moving toward decarbonization, so if a country can add more value and build manufacturing facilities, then they'll get a bigger slice of this new economic pie.

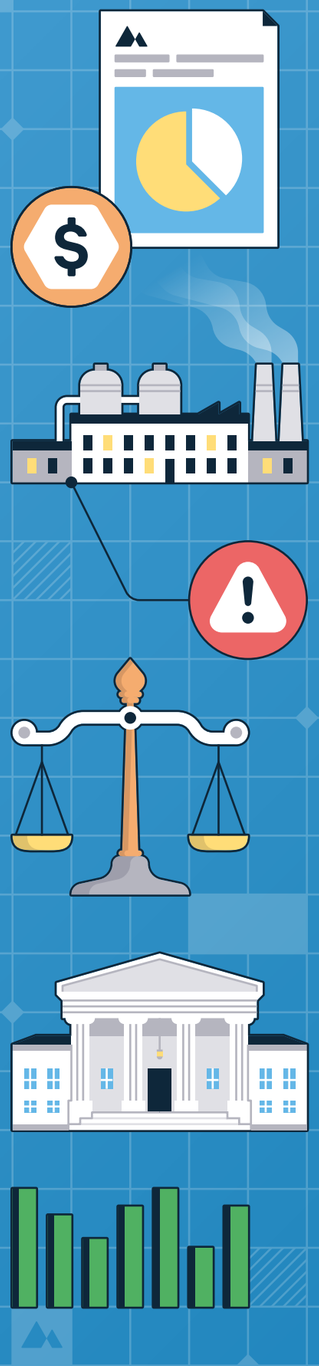
The challenge for the United States, when you think in the framing of energy security and geopolitics, is that critical mineral supply chains are almost wholly dominated by China. This challenge has been an interesting, under-the-radar trend that we might see more of going forward: how resource-rich countries capture value from the resources they have and that they know the world needs going forward.

Relatedly, we need to think carefully about the role of the United States in the global energy system. I'm thinking particularly about expanding US export capacity for liquefied natural gas, which is going to be a big political debate over the coming years because, in the aftermath of the European energy crisis, we're seeing a huge expansion of that capacity. The United States plays a significant role in global energy security, yet this role comes with climate implications and potentially domestic-market implications. I think that's going to be a rich conversation—we'll see different dynamics arise over time, and that's something to watch in the coming year.

Robinson Meyer: I think the United States is already busy playing catch-up. China and Europe have no problem actively subsidizing industries through all kinds of means. They see these industries as part of their industrial policy—China, especially. So, the upcoming election not only determines the path that the United States follows in terms of its decarbonization, but also the role of US firms and the US economy in global decarbonization more broadly. And that's a very big deal. Climate is very much going to be on the ballot.

The podcast interview from which some of these quotes are drawn was originally released on January 2, 2024. The Big Decisions 2024 event in which the rest of these statements were made was held on January 24, 2024. The transcripts have been edited for length and clarity.

> **"Making a lot of stuff requires a lot of energy. We want to move manufacturing back into the United States, where we want to be at the technological frontier for microchips, clean energy goods, and pharmaceuticals."**



New Regulations and Policies

Federal Regulations

Vicki Arroyo: In 2024, the US Environmental Protection Agency is going to launch some big programs that invest billions of dollars in clean ports, zero-emission heavy-duty vehicles, improved methane monitoring, and capping abandoned wells.

We will finalize several regulatory actions. Our Risk Management Program rule will help communities near chemical facilities stay safe in the event of an accident and will facilitate planning to avoid those accidents. Of course, everybody's looking forward to our greenhouse gas standards for power plants and vehicles. We are moving forward with plans to ban methylene chloride in consumer products and establish workplace protections for any remaining uses under the Toxic Substances Control Act, designate two PFAS [perfluoroalkyl and polyfluoroalkyl substances] as hazardous substances under Superfund, and move forward with the PFAS drinking-water rule. That's just the tip of the iceberg, but those are some of the regulatory developments coming up.

Social Cost of Carbon

Kevin Rennert: As a part of the oil and gas rule that was finalized last year, the Environmental Protection Agency updated its social cost of carbon, which is the metric that federal agencies use to quantify the benefits or costs related to emissions increases or decreases. This update to the social cost of carbon, which was based on the current state of the science, revised the number substantially upward. What are the implications of that change? How is the social cost of carbon being used in agency actions in general?

Vicki Arroyo: The updated estimate nearly quadrupled the social cost of carbon to roughly $190 per ton and increased the estimates of the social cost of other gases like methane and nitrous oxide. Applying these new estimates, the final rule for oil and gas operations has climate benefits that are estimated at roughly $110 billion through 2038. The Environmental Protection Agency will use these estimates across our rules, National Environmental Policy Act reviews, and more.

Outside DC: Regional and State-Level Policies

Karen Palmer: One thing I'm keeping an eye out for this year is the rules and regulations to implement the cap-and-invest program in New York State. This is one of several policies and programs that New York is developing to achieve the goals of its landmark Climate Leadership and Community Protection Act that was signed into law in 2019.

These rules are important not only for what they'll mean for New York State, but also as a model for future carbon pricing regimes in other states on the East Coast. Although carbon pricing is in place across some eastern US states, it's mainly focused on electricity generators. The cap-and-invest program in New York would take things broader in different directions.

The second thing I want to mention that will be important this year is relevant to the Regional Greenhouse Gas Initiative (RGGI). I'm looking forward to the agreement that will come out of the ongoing program review of RGGI, regarding both future caps in the program and future design elements.

RGGI historically has been at the forefront of innovations in cap-and-trade policy design. The program pioneered features like using auctions to distribute allowances; using price floors in those auctions; and introducing price steps in the allowance supply curve, which is important because price steps make the program impactful and help RGGI work well and continue to have robust prices even while other state policies are advancing decarbonization.

What we've seen in the recent RGGI auctions is a steady increase in the allowance prices. This trend suggests that the market believes the program will continue to be important, as several states that participate in RGGI have very ambitious decarbonization targets going forward. I look forward to seeing how the program evolves in the next round with respect to program-design decisions.

Permitting

Karen Palmer: A policy issue that stands out for me is progress on legislation to address the various barriers to investment in energy infrastructure, including permitting. Not much has happened on this topic in the policy space in recent years, unfortunately.

We all know that addressing climate change is going to require massive and unprecedented investment in clean sources of energy, like renewables, the grid, hydrogen production, and pipelines, among other types of facilities. The Inflation Reduction Act provides important economic incentives in the form of tax credits for many of these crucial investments. But achieving all the investments that are needed to meet our national climate goals in a timely fashion is going to require overcoming various obstacles: supply-chain cost increases, lengthy interconnection queues for new electricity generation, and streamlining federal permitting-approval processes.

Part of the political negotiations that went into passing the Inflation Reduction Act in 2022 was an agreement between the Biden administration and Senator Joe Manchin (D-WV) to consider, in advance, legislation that would accelerate the permitting of energy infrastructure. One aspect of that proposal was a special focus on 25 priority energy projects that were designated by the president. That bill didn't pass in the Senate, and no other bills that were introduced in 2023 and designed to address similar issues have made it over the finish line.

This policy discussion is not over, but the lack of progress on permitting this year probably is slowing the pace at which the promises of the Inflation Reduction Act will be delivered.

Rich Powell: All the incentives in the Inflation Reduction Act occur in an environment in which permitting at all levels is a devastating problem. Federal environmental reviews, federal environmental permits, regional interconnection queues, state and local technology-specific zoning and setback requirements—all these things are having a massive drag effect on deployment of clean energy technology alongside very high interest rates. We actually can get a bipartisan legislative deal on permitting reform. I was heartened by some remarks in January from Senators Joe Manchin (D-WV) and John Barrasso (R-WY); they said they're keeping hope alive that a deal may be possible by the end of this year. I certainly hope that's the case and will be working on and supporting that, but that really will be the gas or the brake on how impactful the whole regime will be.

Supreme Court Decisions

Chevron Decision

Kevin Rennert: The courts will have a big sway over the energy- and environmental-policy landscape in the coming year. In particular, one of the cases that we're tracking has to do with the *Chevron* deference doctrine. This is a Ronald Reagan–era precedent. The federal courts have to defer to an administrative agency's interpretation of the statute that is being administered. This ruling also will come on the heels of some other pretty significant and consequential rulings, including ones where the court has revisited what is referred to as the major questions doctrine.

Lisa Heinzerling: It's hard to overstate the importance of the *Chevron* doctrine to administrative law and therefore to the power of federal administrative agencies. What *Chevron* did is solidified the Supreme Court's approach to agencies' statutory interpretations into a very handy, understandable two-part test. The first part: Did the statute clearly allow or forbid the answer that the agency gave? If so, that meaning prevails. The second step: Is the statute ambiguous on this point? In that case, the agency's reasonable view prevails, with the deference given at this stage.

For 40 years this summer, Congress has legislated under this framework, agencies have issued rules under this framework, and the Supreme Court itself has generated a huge body of case law under this framework. But the Supreme Court is now poised, I believe, to upend this whole longstanding framework. I think that it will either be outright overruled, which would not be surprising, or it will be so limited that it will be almost unrecognizable. We're in for not only the demise of *Chevron* in a very substantial way, but we're also in for a whole new world, and we'll have to see what the court comes up with.

I think one thing is certain: agencies that are working on rules now cannot expect courts to defer to them in the future in the way that the courts deferred to agencies under *Chevron*.

Major Questions Doctrine

Lisa Heinzerling: The major questions doctrine really is a limit on the power of Congress. Congress cannot delegate an issue to an agency to decide if the issue is important, in the court's view, unless Congress gives a super clear directive to the agency. "Super clear" means that Congress apparently needs to look ahead and see future problems enough to be able to name them.

That's a limitation on the power of Congress, not just a limitation on the power of an agency. Again, the idea is that, if the statute is ambiguous and an important question is involved in the statute, then the agency loses. And this idea already, at least in the cases in which the statute is deemed ambiguous, turns *Chevron* on its head. Ambiguity means the agency loses, rather than the agency wins.

Another important thing to know about the major questions doctrine is that it's not applied evenly. It's skewed against ambitious regulation and favors either a lack of regulation or weak regulation. The more important an issue is, like climate change, the more likely ambitious action on it is going to fall prey to the major questions doctrine.

Technology Trajectories

Clean Energy

Robinson Meyer: Solar manufacturing in the United States is doing very well. There's this great chart that uses Q3 in 2022 as a baseline and shows the before and after. What you see is that solar installation is taking off. Solar already was going at a fast clip before the Inflation Reduction Act passed. It's continuing at an even faster clip, which is kind of expected. All these bounties are being paid directly, and a relatively small number of companies can take advantage of them—and we know those companies are taking advantage of them.

Battery manufacturing is doing quite well, too. That's exactly what we see in the factory data and the industrial data, as well. Just enough points of investment so that the electric vehicle "Battery Belt" is being built over time.

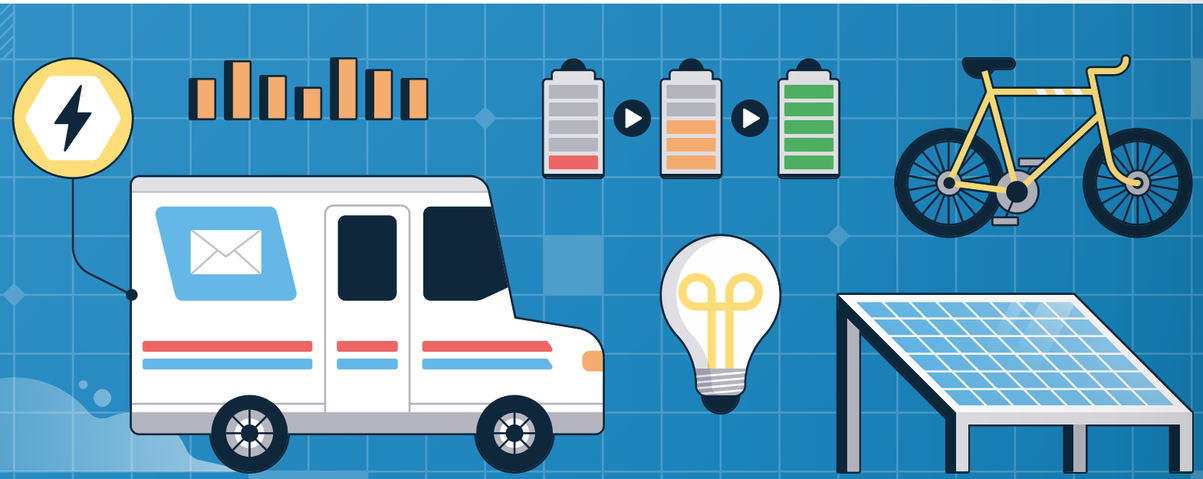
Where it then starts to get a little slower is wind energy, both offshore and onshore. Last year wasn't a great one for wind energy. I think what's tough is that we're also coming out of an extremely anomalous interest rate. The interest rate really affects clean energy projects, because most forms of clean energy investment are a trade-off in which you have no fuel risk—your fuel is the wind or the sun—but you have a lot of capital risk. I'm curious to see how things start to respond if the Federal Reserve cuts interest rates this year.

Rich Powell: Last year was incredible for investments in carbon capture and carbon management. I think last year saw more investment in carbon management than wind energy. Just the three largest offtake contracts signed for carbon management would have more net effect on emissions reductions than all the electric vehicles that currently are on the road in the United States. We saw multiple billion-dollar acquisitions of companies that will provide either carbon-capture technologies or provide carbon dioxide movement and storage infrastructure, as well. I think the expansion of the 45Q tax credit is playing a big role in that. Among all the tax credits in the Inflation Reduction Act, 45Q is another one with strong bipartisan, durable support. So, folks can build a long-term investment thesis around it, which I think helps, as well.

Electric Vehicles

Joseph Majkut: I'll be very interested to learn more about what states are doing on electric vehicle deployment. One of the biggest uncertainties in the medium term for climate and energy issues is, How quickly does the American consumer embrace electric vehicles—everything from e-bikes to the Cybertruck? I'm curious about what states can do to accelerate uptake, what consumers really need to see for demand to increase, how states will deal with balancing the electric grid and charging stations, and all the other things that have to be financed to create a full ecosystem for electric vehicles. This is an area in which I think states have a lot of authority. Some states clearly want to have a leadership position in this space, so I'll be watching for that in the coming year.

Vicki Arroyo: A good example is the US Postal Service. The Environmental Protection Agency has a unique role in reviewing and commenting on environmental impact statements from other federal entities. In combination with White House efforts and incentives in the Inflation Reduction Act, the Environmental Protection Agency helped move the Postal Service from purchasing electric vehicles as 10 percent of their fleet to 62 percent, in part because the agency urged the Postal Service to evaluate and consider the true benefits of shifting to electric vehicles for their government fleet.



Interest Rates

Rich Powell: First and foremost, capital is the fuel that will power the clean energy transition. And capital is extremely expensive right now. For every 500 basis points of additional interest rates that a project has to deal with, the cost of the project doubles. We have seen 500 basis points added to interest rates as a measure to control inflation. And while that regime remains in place, clean energy will be much more expensive, whereas I think our entire policy space and policy advisory space became very comfortable over the last decade in a world of extremely cheap capital. We had the idea that we were going to constantly see the learning curves come down for all these technologies. And that expectation then became built into all the models that we all use for decisionmaking.

We've seen a hard asymptote. In fact, we've seen a number of technologies come back up that curve—offshore wind and onshore wind, in particular. We need to get overall spending under control, so we can get inflation under control, so we can start to bring interest rates back down. That's the most important thing for the clean energy transition.

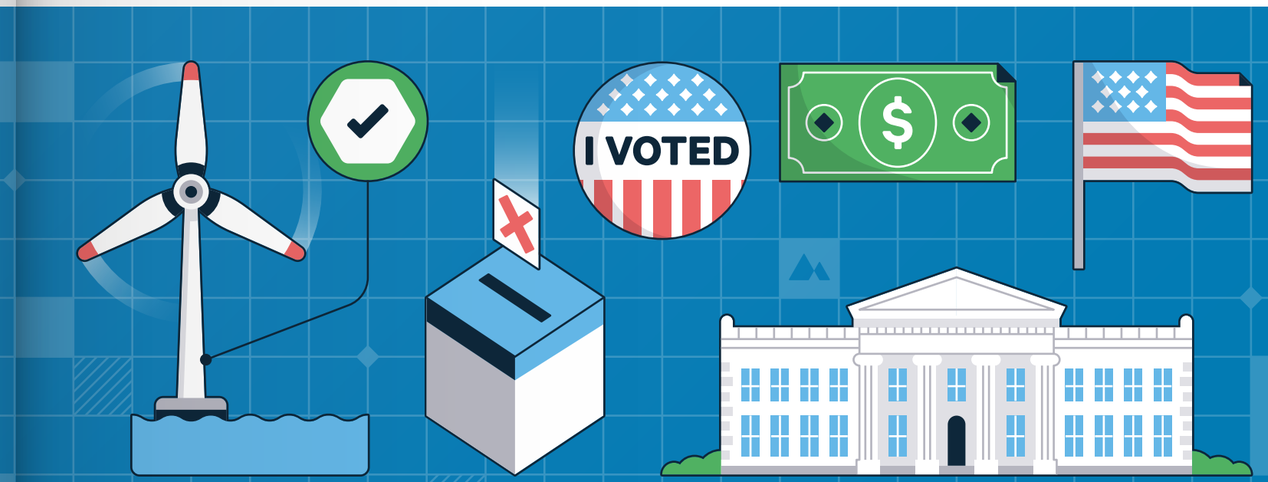
Picking a President

Robinson Meyer: The biggest decision of all in 2024 will be made by several hundred thousand voters who are concentrated in Arizona, Colorado, Nevada, Michigan, Wisconsin, Georgia, and maybe Ohio. As many of us know, it's a hugely consequential election for energy and environmental policy. It's an election that will determine not only the role that the United States takes with decarbonization in its own path—whether the United States meets Paris Agreement goals, US participation in international climate processes—but also the role that American companies and the American economy plays in the global decarbonization process.

What's interesting about the industrial policy that the United States has embarked on, through the three big Biden-era statutes, is that in some parts of this policy, we're playing catch-up; for instance, with growth in electric vehicles. But in some areas, the United States is at the technological frontier—say, in software. These different areas require very different kinds of policy playbooks. I think it's the areas where we're playing catch-up that could be most at risk in a future administration. ■

> "The biggest decision of all in 2024 will be made by several hundred thousand voters who are concentrated in Arizona, Colorado, Nevada, Michigan, Wisconsin, Georgia, and maybe Ohio."

Elizabeth Wason is the senior manager, editorial, at Resources for the Future.



Thinking about Giving, Impact, and the Future

Resources magazine recently spoke with Resources for the Future (RFF) Board of Directors Member Barbara Kates-Garnick, who is a professor of practice and senior research fellow at the Fletcher School of Tufts University. She previously served as the undersecretary of energy and as a public utility commissioner for the Commonwealth of Massachusetts, a corporate officer at a major US utility, and a consultant on strategic energy initiatives. Below are excerpts from the conversation, which covered Kates-Garnick's approach to philanthropic giving and the importance of looking at problems holistically.

Supporter Spotlight

In the RFF Supporter Spotlight, our partners and colleagues share their insights about climate, energy, and environmental issues and how they've made a difference by working with Resources for the Future—all in their own words.

R*esources*: Let's start out by asking what brought you to RFF. Why are you interested in improving environmental decisionmaking?

Barbara Kates-Garnick: I was first introduced to RFF when I was a graduate student, and I relied on RFF to provide an analytical framework for the work that I was doing—so, I feel like I've been part of the organization indirectly for many, many years. Linking the environment and energy has been important for my entire career. This linkage continues to be important as new actors, players, and imperatives move the energy transition forward. For me, my interest in these topics revolves around not just decisionmaking, but also around my passion for future generations.

Given that you've worked in the energy and environmental fields in different sectors—government, academia, and elsewhere—what would you describe as the role for RFF's independent research and analysis?

RFF is critical for understanding the nexus between environmental policy, energy policy, and a successful energy transition. I think RFF is a "crown jewel" that helps decisionmakers in Congress, the federal government, the states, and the private sector as they all wend their way through very complex problems of long-term duration.

This issue of the magazine focuses on the future of the US electric grid. What do you think RFF brings to the table on this key part of decarbonizing the economy?

The issue of electric grid transmission is critical to the energy transition. By unpacking the various aspects related to grid infrastructure, RFF is bringing to the forefront of consideration a knowledge of economics and an understanding of the significance of equity. RFF looks at problems holistically—from the perspective of the states, the federal government, economics, and industry. All of that comes together in RFF's work.

"I think Resources for the Future is a 'crown jewel' that helps decisionmakers in Congress, the federal government, the states, and the private sector as they all wend their way through very complex problems of long-term duration."

Photo (above) Kates-Garnick (third from left) talks with RFF board members (left to right) Janet Clark, Vicky Bailey, and Susan Tierney

Photo (right) Kates-Garnick with her husband Marc

What do you think makes RFF special?

The quality and depth of analysis are what sets RFF apart from other organizations. When you look at RFF research, you know that you are getting analysis that's driven by facts and experience. It all comes back to the excellent RFF researchers who are engaged in the studies and delve into connecting the complex pieces of multiple topics.

You and your husband Marc have been donors to RFF for the past four years. When you consider your philanthropy, do you use any particular criteria to help shape your approach to giving?

When you think about giving, you must consider impact, and you must think about the future. Those are important criteria that Marc and I use when we decide how to direct our philanthropic giving. I can think of no better place than RFF to support in the energy and environmental fields, based on RFF's impact, its analysis, and the fact that it is evenhanded in how it approaches complex problems, which makes it an enduring institution.

What's the first thing that comes to mind when you think about the impact of your financial investment in RFF?

First, I think about the researchers; I think about the hard work that they are doing to unpack highly complicated decisionmaking. In giving to RFF, I feel strongly that we are directly supporting the research and the people who are designing the studies and writing the papers. For me, that is the real pleasure and joy of directing our philanthropic dollars to RFF. ■

Four Ways You Can Support RFF

1 Give through our website

Visit **www.rff.org/donate** to make a one-time donation, or to set up a monthly recurring donation.

2 Give through the mail

Send your check to Resources for the Future | 1616 P Street NW, Suite 600 | Washington, DC 20036

3 Give through a donor-advised fund

Donate through a DAF account at a community foundation or financial institution to support RFF while receiving favorable tax benefits.

4 Give through a will, trust, or gift plan

Include RFF in your estate plans to provide meaningful, long-lasting support.

Discover other ways to give at **rff.org/waystogive** or contact Ryan Sabot at **rsabot@rff.org**

In Focus

The video series In Focus gives researchers at Resources for the Future (RFF) a platform to share insights related to current events in energy and the environment. The series launched in 2022; since then, In Focus videos have tackled topics that range from climate optimism to carbon dioxide removal.

Transcribed here is a video featuring Molly Robertson, a senior research associate at RFF. Robertson discusses how challenges in transporting electricity on the US electric grid may affect the clean energy transition. Renewable energy sources such as wind and solar often need to be located far from the centers of demand for electricity, and the construction of new transmission lines that connect electricity to consumers tends to be slow: costs and complex permitting processes can present obstacles to grid expansion. Robertson shares various policy solutions that can help facilitate the build-out of new transmission lines—relevant insights, given that the Federal Energy Regulatory Commission, the federal agency that regulates the transmission of electricity across states, is working on a new regulation that could help accelerate the expansion of the grid.

This In Focus video was originally released on May 13, 2024. The transcript has been edited for length and clarity.

Photo
Mike Harrington / Getty Images

Connecting People to Clean Power

TEXT Molly Robertson, Annie M. Tastet, and Matt Fleck

The clean energy transition is likely to strain infrastructure on the electric grid in the United States in a couple of key ways.

The first way relates to electrification. We anticipate that the grid system will experience a lot more demand as sectors like transportation and buildings transition to using electricity, so the existing electric grid and existing transmission lines will have to transport a lot more electricity.

The other way relates to cleaning up the mix of sources of electricity generation and the power sector itself. As we move to a clean energy system, we're going to see a lot more wind and solar on the grid.

New wind and solar can't just be plugged into the grid wherever the connections to the grid already exist or where demand for electricity is highest. You have to look for places where the sun and the wind are available to be captured. We're going to have to build generation in the places where that generation is most beneficial and transport the electricity. That siting means that we'll need more transmission lines that don't currently exist.

Policymakers increasingly are becoming interested in solving this problem. A lot of proposals have been raised that potentially could deploy additional transmission lines. The first is tax credits for new transmission lines. A second is minimum electricity-transfer requirements between regions that would require new transmission to be built. The third is enhanced planning processes that would require regional transmission operators to think far in advance about transmission needs, where new generation and new electricity demand will grow, and how to connect those critical points of generation and demand.

We're still waiting to see exactly how transmission policy will shape up, but a lot of people are thinking critically about how to solve these problems. ■

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Read more about options to support RFF on page 47 of this issue.