ENERGY LAW JOURNAL

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Reform of Legal and Regulatory Impediments to Investments and Cross-Border Energy Trading by Nepal and Other South Asian Nations . . . . *Madhab Raj Ghimire, Deepshikha Wagle, Sukhyati Malla, Brian Barkdoll*

TRANSCRIPTS

The Energy Law Journal & Energy Bar Association's January 12, 2022, online symposium: "Past the Tipping Point: How Regulators and Utilities Are and Will Be Looking at Ways to Mitigate the Inevitable Impacts of Climate Change"

BOOK REVIEWS

Electrify: An Optimist's Playbook for Our Clean Energy Future . . . . *Reviewed by Kenneth A. Barry*

Unsettled: What Climate Science Tells Us, What It Doesn't, and Why It Matters . . . . *Reviewed by Kenneth A. Barry*

Regulating Public Utility Performance: The Law of Market Structure, Pricing and Jurisdiction . . . . *Reviewed by David P. Yaffe*

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Allegheny Def. Project v. FERC: The Jenga Block Pull Foretelling a Fatal Crash of FERC's Tolling Order Façade . . . . *Michael Campbell*

ENERGY BAR ASSOCIATION®

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THE ENERGY BAR ASSOCIATION
UNIVERSITY OF TULSA COLLEGE OF LAW

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ENERGY BAR ASSOCIATION

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103: Federal Oil Pipeline Regulation
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107: Energy Trading
108: Environmental Law
109: Introduction to Hydro Power
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Energy Law Journal
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The *Energy Law Journal* publishes legal, policy, and economic articles and other materials of lasting interest with significant research value on subjects dealing with the energy industries. The *Energy Law Journal* also welcomes articles and other materials on emerging issues and significant developments affecting the energy industries. Articles by members and non-members of the Energy Bar Association are welcomed. The *Journal* publishes articles and other materials of varying length that provide a full consideration of the issues and opposing viewpoints. The opinions expressed in the published materials are those of the writers and are not intended as expressions of the views of the Energy Bar Association. All submissions must contain a synopsis, table of contents, and a brief biographical statement about the author(s). Style and form of citations must be in conformity with the "Blue Book," as well as the *Energy Law Journal* Style Manual posted on the Energy Bar Association website. All submissions should be sent to Harvey L. Reiter, Editor-in-Chief, *Energy Law Journal*, by mail to Stinson LLP, 1775 Pennsylvania Ave., N.W., Suite 800, Washington, D.C. 20006 or electronically to harvey.reiter@stinson.com. By submitting materials for publication in the *Energy Law Journal*, authors agree that any such materials, including articles, notes, book reviews, and committee reports, published in the *Journal* are considered "works made for hire," and authors assign all rights in and to those written works to the Energy Bar Association. The Energy Bar Association hereby grants permission for reproduction and distribution of copies of written works herein for non-commercial use, provided that: (1) copies are distributed at or below cost; (2) the notice of copyright is included on each copy (Copyright © 2022 by the Energy Bar Association); and (3) the *Energy Law Journal* and the author are clearly identified on each copy. A full digital version of the *Journal* is free to all members of the Energy Bar Association. For subscriptions to the hard copies of the Journal please see subscription information at: \"Subscribe Online.\" Back issues are available by contacting the William S. Hein & Co. at (800) 828-7571.

The Energy Bar Association Website

The Energy Bar Association (EBA) is an international, non-profit association with eight regional chapters throughout the United States and Canada, that strives to advance the professional excellence of those engaged in energy law, regulation and policy through professional education, exploring diverse viewpoints and building connections. EBA membership is open to those interested in energy law including attorneys, consultants and other energy professionals, academics, and students.

For over 75 years, the EBA has provided the superior educational programming, networking opportunities, and information resources that industry insiders need to grow professionally in today's constantly evolving energy industry.

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COMMITTEE REPORTS

Neither the reports of the Energy Bar Association Committees nor the annual review of the Canadian energy law developments are included in the print version of the Journal. Rather they are published online on the EBA's website at www.felj.org. Persons citing to the reports should use the following format: [Title of Report], 43 Energy L.J. [page number] Online (2022), [link to report]. Included in the full electronic version of the Energy Law Journal, Volume 43, No. 1, are the following steering reports:

Electricity

Enforcement and Compliance

Gas, Oil, and Liquids

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President's Award

This Award is given occasionally to an individual that has made an extraordinary contribution to the profession or the development of energy law over a long career.

2019	Robert S. Fleishman
2017	Robert R. Nordhaus
2010	Richard D. Cudahy (Judge)
2008	Richard J. Pierce, Jr.
2006	Senator Pete V. Domenici
2004	Charles B. Curtis
2002	Stephen F. Williams (Judge)
2001	Congressman John D. Dingell

ENERGY BAR ASSOCIATION
Paul E. Nordstrom Service Award

This Award was created in memory of Paul Nordstrom, a past President of the Energy Bar Association (EBA) and motivating force in the organization of the Charitable Foundation of the EBA (CFEBA). The first award was given to Paul posthumously. It is an award to honor and to recognize exemplary long-term service or a particularly significant example of public service by a current or past member to the community through the EBA, the CFEBA, or the Foundation of the Energy Law Journal. Exemplary community service outside of these organizations may also be considered as a criterion for the Award.

2021	David T. Doot	2015	A. Karen Hill
2020	Harvey L. Reiter	2014	Paul B. Mohler
2019	James Curtis "Curt" Moffatt	2013	William Mogel
2018	Susan N. Kelly	2012	Freddi L. Greenberg
2017	Michael Stosser	2011	Richard Meyer
2016	Robert S. Fleishman	2010	Shelia S. Hollis
		2009	Paul E. Nordstrom

ENERGY BAR ASSOCIATION
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This Award recognizes innovation and superior advocacy by members of the state utility regulatory bar. The award is consistent with the State Commission Practice Committee's goal to be a resource to lawyers who focus their practice on state energy regulatory matters.

2021	Frank R. Lindh
2020	Holly Rachel Smith
2019	H. Russell Frisby
2019	Andrew O. Kaplan
2016	Sandra Mattavous-Frye
2015	Stephen H. Watts, II
2014	Charles Gray
2013	Jeff Genzer
2012	Sonny Popowsky
2011	Ben Stone
2010	James Van Nostrand

ENERGY BAR ASSOCIATION
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This Award was created in memory of Jason F. Leif, a past President of the Energy Bar Association (EBA), a past President of the Houston Chapter of the EBA, and a motivating force in the revitalization of the Houston Chapter. This award honors and recognizes exemplary long-term service, or one or more particularly significant examples of service, by an EBA member to one or more of the EBA Chapters, enhancing the role of the EBA Chapters in representing EBA's values and character at the regional level. Exemplary service to the community in connection with EBA Chapter activities may also be considered. The EBA Board created this award in 2018, and voted unanimously to honor Jason as the first recipient of the Award.

2021	Cynthia Brown Miller
2020	Crystal McDonough
2019	Daniel T. Pancamo
2018	Jason F. Leif

Energy Bar Association
Champion for Diversity and Inclusion Award

The Champion for Diversity and Inclusion Award, is given to a Member who has embodied the principles of the Diversity and Inclusion Policy through their actions in the Associations and/or their professional career. The award is granted as deemed warranted by the EBA Board and may, or may not, be granted annually. Emma Hand was named as the first recipient of this award.

2022	Andrea Wolfman
2021	Sherry Quirk
2020	Chief Judge Carmen A. Cintron
2019	Emma Hand

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And we gratefully acknowledge those EBA members and others who have so generously contributed in the past.

ENERGY LAW JOURNAL

The Energy Bar Association is an international, non-profit association. Founded in 1946 as the Federal Power Bar Association, the Association currently has approximately 2000 members. The Association's voluntary membership is comprised of government, corporate, and private attorneys, as well as energy professionals from across the globe, and includes law students interested in energy law. The mission of the Association is to promote the professional excellence and ethical integrity of its members in the practice, administration, and development of energy laws, regulations, and policies. In addition to publishing the *Energy Law Journal*, the Association organizes and sponsors a number of activities, including two national conferences a year, and numerous continuing legal education (CLE) programs each year. The Association also sponsors eight formal chapters in the United States and Canada and committees that monitor and report to the membership on developments of interest. Complete membership and subscription information can be obtained from the Association at 2000 M Street, NW, Suite 715, Washington, DC 20036, or by contacting us at (202) 223-5625 or by visiting EBA-Net.org.

Twice a year, the *Energy Law Journal* publishes legal, policy, and economic articles and other materials of lasting interest with significant research value on subjects dealing with the energy industries. The Journal also welcomes articles and other materials on emerging issues and significant developments affecting the energy industries. Articles by members and non-members of the Association are welcomed. The Journal publishes articles and other materials of varying length that provide a full consideration of the issues and opposing viewpoints. All submissions must contain a synopsis, table of contents, and brief biographical statement about the author(s). Style and form of citations must be in conformity with the "Bluebook," as well as the *Energy Law Journal* Style Manual posted on the Energy Bar Association website. All submissions should be sent to Harvey L. Reiter, Editor-in-Chief, *Energy Law Journal*, by mail to Stinson LLP, 1775 Pennsylvania Ave., N.W., Suite 800, Washington, D.C. 20006 or electronically to harvey.reiter@stinson.com. The opinions expressed in the published materials are those of the writers and are not intended as expressions of the views of the Energy Bar Association. Inquiries about advertising in the Journal should be addressed to Michele Smith at the Energy Bar Association at (202) 223-5625. The Journal is indexed in the INDEX TO LEGAL PERIODICALS, the CURRENT LAW INDEX, WESTLAW, and LEXIS SERVICES.

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DIVERSITY AND INCLUSION POLICY

The Energy Bar Association (EBA), the Charitable Foundation of the Energy Bar Association (CFEBA), and the Foundation of the Energy Law Journal (FELJ) are committed to the goals of fostering an inclusive and diverse membership and increasing diversity across all levels of the Associations. Attorneys, energy professionals and students with varied and diverse characteristics practicing in the energy field are welcome to join our ranks, regardless of race, creed, color, ethnicity, Native American, Alaska, or Hawaiian Native tribal membership or descendance, gender (including gender identity or expression), sexual orientation, family and marital status (including pregnancy), family responsibilities, religion, national origin, age, personal appearance, political affiliation, veterans status, disability, source of income (government, solo, corporate, firm practice), or place of residence or business (geographic diversity) and are encouraged to become active participants in the Associations' activities.

PRESIDENT'S MESSAGE

As I write this, the Russia-Ukraine war enters its 65th day, and it is hard to imagine focusing on anything else. There are many implications for energy. Russia has cut off natural gas to Poland and Bulgaria, using energy resources as a weapon while it attacks cities and civilians in eastern Ukraine. As a result of the conflict, commodity prices are soaring. But the humanitarian crisis is the real story, and it is heartbreaking. Sitting here today, it is hard to fathom how this war ends.

The Energy Bar has a small but important role to play. Through our Charitable Foundation, we are raising money at the Annual Gala for the World Central Kitchen's efforts to feed refugees and communities that have returned to their newly liberated but devastated towns and cities. Through our programming and publications, we will continue to help our members, policy makers, and leaders understand the implications of the crisis on our national energy needs and policies. And most importantly, through you as members of the Energy Bar, we will continue to represent clients, companies and communities as they navigate the myriad issues swirling in this volatile moment.

In the last issue of the Energy Law Journal, the President's Message remarked on the work that the Energy Bar Association is doing on better understanding the challenge of Energy Insecurity in the United States and Canada. Energy Insecurity is the loss or threatened loss of energy required for our modern lives.[1] Today, real time, we are reminded once again across the world stage how important access to energy is for life and civilization. On this topic, I am exceptionally excited to announce that the Energy Bar Association is going to be working with the Columbia University School of International and Public Affairs Center on Global Energy Policy, the Columbia University Mailman School of Public Health, and the Columbia University Law School's Sabin Center for Climate Change Law on an initiative to reduce energy insecurity in the United States and Canada. This initiative supports the EBA's tradition of doing well by doing good and will create opportunities for our young attorneys and professionals, our regional chapters, and our exceptional educational programing.

There also are many opportunities for scholarship, research, and analysis around energy insecurity, and as always, the Energy Law Journal is ahead of the curve having focused on this topic in past issues. I expect continued opportunities for future articles that pull from the EBA's Energy Insecurity Initiative.

In this edition, the Energy Law Journal is publishing a transcript from a symposium titled "Past the Tipping Point: How Regulators and Utilities Are and Will be Looking at Ways to Mitigate the Inevitable Impacts of Climate Change." Moderated by the ELJ's very own Editor-in-Chief, Harvey Reiter, and featuring panelists Roshi Nateghi, Judsen Bruzgul, Heather Payne, and Michael Craig, the panel examined what policy makers and utilities already are doing and still can do to mitigate various impacts of climate change on the reliability, resiliency, and affordability of utility services. The panel also focused on legal and practical limits on regulatory change and available tools and strategies that can be used to decarbonize the grid.

1. SONAL JESSEL, SAMANTHA SAWYER & DIANA HERNÁNDEZ, ENERGY, POVERTY, AND HEALTH IN CLIMATE CHANGE: A COMPREHENSIVE REVIEW OF AN EMERGING LITERATURE 1-2 (2019), https://www.frontiersin.org/articles/10.3389/fpubh.2019.00357/full

In the article “Reform of Legal and Regulatory Impediments to Foreign Investment and Cross-Border Energy Trading by Nepal and Other South Asian Nations,” Madhab Raj Ghimire, Deepshikha Wagle, Sukhyati Malla, Brian Barkdoll, and Narayan Ghimire explore the fascinating energy dynamic between Nepal and its giant, populous neighbors China and India. Nepal’s vast hydropower resources offer foreign, sprawling population centers the promise of clean, renewable energy, but with great cost and uncertainty. The authors highlight challenges from conflicting national laws, uneven bargaining power, and the difficulty of implementing legal reforms in the region.

Closer to home, we have a pair of articles that focus on different aspects of regional electric markets. In “How Does Restructuring of Electricity Generation Affect Renewable Power,” authors Shelley He, Eric Biber, Helen Aki, Maribeth Hunsinger, and Stephanie Phillips take a comprehensive historic look through decades of data to show the impact of restructuring efforts on divestiture and siting across the country. The authors conclude that certain forms of generation markets can advance renewable energy development, whether a utility system is public or private may not drive outcomes. In “Too Much is Never Enough: Constructing Electricity Capacity Market Demand,” authors Todd Aagaard and Anrew N. Kleit explore their findings on the drivers of capacity markets, arguing that they are influenced more by politics and regulators’ personal judgement than by competition, and that this leads to customers paying billions of dollars for excess capacity the system does not need.

Finally, William G. Bolgiano investigates how hydrogen pipelines can and should be regulated in “FERC’s Authority To Regulate Hydrogen Pipelines Under The Interstate Commerce Act.” Surveying legislative history and precedent to distill a test to delineate jurisdictional boundaries created by the Natural Gas Act, the Interstate Commerce Act, and the Interstate Commerce Commission Termination Act, the author argues that the Federal Energy Regulatory Commission would be the more appropriate and abler regulator.

Once again, I want to thank Journal’s leadership and its volunteers for putting together another wide-ranging, yet deep and serious series of articles. Editor-in-Chief Harvey Reiter, Executive Editor Caileen Gamache, and Administrative Editor Nicholas Cicale continue to devote countless hours from initial conversations with authors to vetting, testing, and editing articles with the help of the Journal’s all-volunteer editorial board. I also want to thank the University of Tulsa College of Law, our student editors there, and faculty advisor Professor Warigia Bowman, who do such great work issue after issue. Through your efforts and dedication, this publication continues to be the premier journal in energy law and a source of great pride for EBA.

Sincerely,

/s/ Mosby G. Perrow
Mosby G. Perrow
President, Energy Bar Association

EDITOR-IN-CHIEF'S PAGE

Whether to simply humor me or not, the Journal's Executive Editor, Kat Gamache, has remarked that she looks forward to the "time capsules" that I've made part of the Editor-in-Chief's page (well, more accurately, pages). For the last few years the worldwide COVID pandemic and the now millions of lives it has taken, has been a subject of these pages, as have the spread of disinformation, the impeachment (the second one) of the then President, the insurrection at the Capitol instigated by that same former president and the UN's report on now irreversible impacts of climate change. We enter this new edition of the Journal in a still different world than we were in just six months ago.

COVID, unfortunately, continues to plague the globe. As we go to print, nearly a million persons in the United States have died from the disease and more than six million worldwide. The good news is that its spread has receded and death tolls have dropped substantially. But we've unfortunately seen a new U.S. export – the trend to turn even public health measures into political issues. A caravan of Canadian truckers dissatisfied with Canada's vaccine and masking requirements created havoc with the lives of Ottawa residents for weeks as the truckers camped out in that nation's capital. The impact spilled over to the U.S. when another caravan blocked passage of goods across the Ambassador Bridge connecting Windsor, Ontario to my hometown, Detroit – our country's busiest international border crossing.

We've seen a barrage of other news. There was the nearly spectator-free Beijing Olympic games marred further by another Russian doping scandal and against the backdrop of the host country's repression of its Uyghur population -- including mass detentions in "reeducation camps." The prolonged owner lockout of major league baseball players came to an end. Matthew Stafford, who in thirteen years as quarterback of the hapless Detroit Lions did not win a single playoff game, won four in his first year with the Los Angeles Rams, including the Super Bowl. New Orwellian phrases have been added to the vocabulary – "special military operation" to describe Russian war crimes, "denazification" to rationalize Russia's attack on a country led by Volodymyr Zelenskyy, a democratically-elected Jewish president and "legitimate political *discourse*" to describe the January 6, 2021 *physical* attacks on the Capitol and its police officers. Add to the mix the acrimonious hearings over the nomination and ultimate confirmation of Ketanji Brown Jackson, the first Black woman to serve on the Supreme Court, the shocking leak to Politico of a draft opinion by Justice Alito striking down *Roe v. Wade*, and the defeat of xenophobe, antisemite, and Putin admirer Marie Le Pen in France's presidential election. And who will soon forget actor Will Smith's physical assault on comedian Chris Rock before millions during the live broadcast of the Oscars? And who, unfortunately, will remember months from now that there were ten mass shootings in the U.S. during a ten-day period in April?

While unemployment levels have dropped dramatically – nearly to pre-pandemic levels - inflation has increased to levels not seen for forty years. The increase has been significant enough that even persons who were unemployed a year ago can ironically still feel worse off because, though now employed, their rising wages have not kept up with faster rising prices.

Fighting a subpoena by the House of Representatives' Jan. 6th committee, John Eastman sought to withhold communications with former President Trump as shielded by attorney client and work product privileges. But after an *in cam-*

era review of the disputed documents, federal district court Judge Daniel Carter not only rejected the claim, but found that the claimed "work product" was in fact unprotected action in furtherance of a crime. It was "more likely than not," he found, both that Trump and Eastman "dishonestly conspired" to obstruct the January 6 joint session of Congress and that they had unlawfully attempted to obstruct an official proceeding.[1] In a separate proceeding a New York state trial judge found Trump in contempt of court for failing to turn over documents to the state's Attorney General in connection with her civil fraud investigation into the business practices of the former president and his company.

And of course, there is the Russian invasion of Ukraine. It has been horrific to watch the news as Russian artillery, bombs and missiles indiscriminately – no, intentionally killed thousands of civilians, destroyed homes, businesses and infrastructure – including hospitals and schools - and created nearly five million refugees. The world (and our own Congress) has remained largely united against the invasion. But one notable exception to this unity was the nauseating spectacle of a former President of the United States -- already previously impeached (the first time) for holding military aid to Ukraine hostage to his demands that Ukraine investigate his political rival -- joined by his former Secretary of State, actually praise Russia's President Putin – a war criminal - for his "savvy" and "genius" military strategy.

Putin's savage war – carried out, not by soldiers, but by a combination of bewildered and untrained conscripts expecting to be welcomed and Russian butchers in uniform who have murdered unarmed civilians in their homes and on the streets and left their corpses to rot, has pushed other major human tragedies occurring around the world off the front pages, in some cases out of the news almost entirely. For example: what the State Department has designated as the Myanmar military's genocide and crimes against humanity against the Rohingya and the Taliban's resubjugation of the women of Afghanistan.

Russia's unprovoked war on Ukraine has also brought new attention both to the vulnerability of nuclear power plants to military attacks and to the vulnerability of Europe, particularly Germany, to cut offs of oil and gas supplies from Russia. While Germany ultimately delayed indefinitely the Nordstream II natural gas pipeline that would have brought new supplies of Russian natural gas to that country and other European nations, Eurostat reports that 30% of the European Union's current oil imports and 39% of its natural gas imports come from Russia. Because of this heavy reliance on Russian imports, months after Russia's invasion of Ukraine and the imposition of severe international sanctions, Russia continues to supply oil and natural gas to Europe. As proof of the adage that even a broken clock is right twice a day (think Space Force, maybe?), the former President warned of this problem several years ago.

Referring to a "rapidly closing window," the February 2022 report of the UN's Intergovernmental Panel on Climate Change issued an even starker warning about the urgency of taking measures to reduce the world's dependence on fossil fuels than its already dire August, 2021 report. And in early March, a study published in the Journal Nature Climate Change, found that more than half of the globe's biggest carbon sink, the Amazon rainforest, could become savannah in a

1. *Eastman v. Thompson, et al.*, Case No. 8:22-cv-00099-DOC-DFM, Order Re Privilege of Docs., slip op. at 39-40 (C.D. Cal. filed Mar. 28, 2022).

couple of decades, further accelerating climate change.[2] Climate change and unchecked authoritarianism both represent existential threats – the first to humanity itself and the second to democracy. The lessons of these reports and the reality of today's geopolitical climate will pose difficult questions for energy policymakers and regulators who may be asked to weigh these geopolitical considerations against concerns about climate impacts.

CNN analyst Fareed Zakaria, for example, has urged that the US ramp up its production and export of oil and gas and for other oil producing nations to do likewise, reasoning in response to climate concerns that Russian fossil fuels would have been consumed anyway, while US production would have come with fewer methane leaks. This would require regulators, for example, to consider expanding authorizations to export liquefied natural gas. The International Energy Agency instead suggests that accelerating the deployment of heat pumps would save "2 bcm of gas use in the first year, requiring an additional investment of EUR 15 billion."[3] Environmentalist Bill McKibben has suggested that President Biden could invoke the Defense Production Act to order the manufacture of heat pumps for delivery to Europe in advance of the next winter heating season, saving enough fuel to nearly eliminate the need for Russian natural gas.[4] Energy continues to play an integral role in world politics.

Last, as a reminder of the importance of editorial independence for scholarly journals like this one, we've also seen a rising level of intolerance with a resurgence of book banning and censorship in public schools. *Inherit the Wind*, the classic 1960 film, dramatized the real life case of a Tennessee science teacher accused of the crime of teaching evolution – the Scopes "Monkey Trial." The film, like the play on which it was based, was written by a screenwriter who had been blacklisted during the McCarthy era and was itself a thinly disguised response to the chilling impact the McCarthy investigations had on free speech. But the court case on which it was based was itself a lesson on the dangers of censorship of ideas.

Nearly a hundred years after the Scopes trial, we see history repeating itself in Tennessee. Last January the McMinn County School Board voted to remove a fifty-year old Pulitzer Prize-winning graphic novel about the Holocaust from its eighth grade curriculum. Their grounds? They objected that the book, which depicted persecuted Jews as mice and Nazis as cats, included a picture of a partially nude cat. As the New York Times story about the dispute recounted, the book's author, Art Spiegleman, "compared the board to Vladimir V. Putin of Russia" and suggested that McMinn officials would rather "teach a nicer Holocaust."[5] Despite the public outcry – and the book's rise to the top of best-seller lists - Tennessee's governor used the incident to propose a law requiring a statewide

2. Sarah Kaplan, *Amazon rainforest is nearing 'tipping point, scientists say,'* WASH. POST, Mar. 8, 2022, at A3.

3. IEA, *A 10-Point Plan to Reduce European Union's Reliance on Russian Natural Gas* Section 7, IEA (Mar. 2022), https://www.iea.org/reports/a-10-point-plan-to-reduce-the-european-unions-reliance-on-russian-natural-gas.

4. Michelle Lewis, *How US-made heat pumps could help weaken Russian power over Europe*, ELECTREK (Feb. 28, 2022), https://electrek.co/2022/02/28/how-us-made-heat-pumps-could-help-weaken-russian-power-over-europe/.

5. Sophie Kasakove, *The Fight Over 'Maus' Is Part of a Bigger Cultural Battle in Tennessee*, N.Y. TIMES (Mar. 4, 2022), https://www.nytimes.com/2022/03/04/us/maus-banned-books-tennessee.html.

review of the content of school libraries in order to root out and remove "age inappropriate" content from their shelves.[6]

And in Virginia, on his first day in office, the new governor issued an executive order banning the teaching of "inherently divisive concepts" in public schools and creating a tip line where parents and others could anonymously report teachers whose class lessons were making students feel uncomfortable. Apparently, as Virginia's Department of Education now interprets that order, it includes the banning of existing programs teaching such "divisive" concepts as "teaching 911," "diversity," "equity" and "inclusion."[7] Other states, including Georgia, New Hampshire, South Dakota, Tennessee and Florida have unfortunately followed suit with similar bans or proposed bans on public school instruction that might make a student feel, for example, "discomfort, guilt anguish, or any other form of psychological distress because of his or her race."[8]

But who is instructing students to feel discomfort *because* of their race? German school children have been instructed for several generations about the country's Nazi past and Nazi claims of Aryan racial superiority to support the extermination of Jews, gays and the Romanies. This no doubt has caused discomfort among the students, many of whose grandparents may have been silent bystanders to Nazi atrocities or worse-- collaborators or perpetrators. Their discomfort, however, was not because of their race, but because of the actions of their forbears. Few would argue that this education has not been for the good.

It is historical fact that in its 1857 *Dred Scott v. Stanford* decision the Supreme Court ruled that the U.S. Constitution was not meant to include American citizenship for any person of African descent,[9] that slavery was enshrined in our original Constitution, and that the Page Act of 1875 placed restrictions on immigration from East Asia and included language referring to the "lewd and immoral" behavior of East Asian women, and the threat they posed to white men and white boys.[10] Teaching these facts might not technically violate some of these new laws, but the classroom discussions they are likely to prompt is what worries teachers. The evidence is accumulating that these laws are promoting teacher self-censorship.[11]

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6. *Tennessee Governor, GOP Push More Scrutiny of School Libraries*, ASSOCIATED PRESS (Feb. 9, 2022), https://news.wttw.com/2022/02/09/tennessee-governor-gop-push-more-scrutiny-school-libraries.

7. Hannah Natanson & Karina Elwood, *Virginia Education Department rescinds diversity, equity programs in response to Youngkin's order*, WASH. POST (Feb. 25, 2022), https://www.washingtonpost.com/education/2022/02/25/maryland-youngkin-education-diversity/

8. See, e.g., Georgia House Bill 1084.

9. 60 U.S. 393 (1856).

10. Section 141, 18 Stat 477, 3 Mar. 1875.

11. Laura Meckler and Hannah Natanson, *New critical race theory laws have teachers scared, confused and self-censoring*, WASH. POST (Feb. 14, 2022), https://www.washingtonpost.com/education/2022/02/14/critical-race-theory-teachers-fear-laws/. And censorship has not been limited to silencing teachers. "[O]fficial reprisal for protected speech 'offends the Constitution [because] it threatens to inhibit exercise of the protected right.'" *Hartman v. Moore*, 547 U.S. 250, 256 (2006) (quoting *Crawford-El v. Britton*, 523 U.S. 574, 588 (1998)) Yet, in nakedly and shockingly overt retaliation for the Disney Corporation's opposition to Florida's "don't say gay" law, the Florida legislature passed a law, signed with great fanfare by the governor, removing the municipal utility status of Reedy Creek Improvement District formed more than a half century ago to provide utility services to the expansive Disneyworld properties. That retaliation was the entire motive for the state's actions could not have been clearer. "Disney and other woke corporations won't get away with peddling their unchecked pressure campaigns any longer," explained Florida's governor as the reason for the legislation. Ian Millhiser, *Ron DeSantis's attack on Disney obviously violates the First Amendment*, VOX (Apr. 23, 2022), https://www.vox.com/23036427/ron-desantis-disney-first-amendment-constitution-supreme-court. State representative Randy Fine, the sponsor of the bill, was equally candid about the retaliatory nature of the legislation.

Actual and threatened book bans are having a similar effect. In April, Florida's Department of Education rejected 41 percent of *math* text books submitted for approval as instructional materials for what it said were references to critical race theory, or CRT. "School book bans are soaring," writes Hannah Natanson of the Washington Post. As she reports, "the American Library Association's Office for Intellectual Freedom counted 330 incidents of book censorship in just the three months from September to November, 2021." That, she adds, was the highest rate of censorship since the Association began tracking it more than thirty years ago.[12] But the bigger impact of this trend is its chilling effect. Natanson reports that school libraries around the country, anticipating possible challenges are engaging in self-censorship and removing books from the shelves.[13]

Thankfully, the editors of this Journal have enjoyed broad editorial independence, a bedrock for the credibility of a scholarly journal. To be sure we have faced reader criticism from time to time about articles we have published. The Journal's readership is comprised of people with different experiences, interests, and perspectives and we know there will be disagreement and (hopefully professional) debate. The Journal promotes scholarship, not censorship.

But do not mistake the Journal's editorial independence for freedom from responsibility. The ELJ is also among the heaviest-vetted law journals in the country and is one of the very few peer-reviewed law journals. We have lost a number of articles over the years because of the rigor of our peer review process, authors finding it simpler to submit their manuscripts to student-run publications. It is easy to see why.

An author's manuscript must pass an initial review by the editor in chief and the executive editor. The article is then reviewed by one and sometimes two or more peer review editors. It is only then sent to the student editors, who proof read, cite check, run plagiarism software and format the article for publication. We do not control the conclusions of our authors, but where there are opposing viewpoints we ask the authors to acknowledge and tackle them fairly. If a reader takes issues with an author's conclusions, we have entertained - and published - counterpoints to the articles. Past editions of the Journal include several examples of responsive articles.

The British Medical Journal (BMJ) has a relationship to its affiliate organization much like the relationship between the ELJ and the EBA and between the ELJ and its Editor-in-Chief. BMJ is editorially independent from its trade-union owner, the British Medical Association. Over fifteen years ago, in words that ring just as true today, it explained the importance of that independence to the credibility of a scholarly journal:

> Editors-in-chief and the owners of their journals both want the journals to succeed, but they have different roles. The primary responsibilities of the editors-in-chief are to inform and educate readers, with attention to the accuracy and importance of journal articles, and to protect and strengthen the integrity and quality of the journal and its processes. Owners are ultimately responsible for all aspects of publishing the journal, including its staff, budget, and business policies. The relationship between owners and editors-in-chief should be based on mutual respect and trust, and recog-

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"Disney," he explained, "is learning that they're a guest in this state. We have given them special privileges for 55 years and it's time for them to remember that we are not interested in their "California values." https://ms-my.facebook.com/newsmax/photos/a.10151127234237377/10159063930367377/?type=3

12. Hannah Natanson, *Schools try to quietly shelf book disputes*, WASH. POST, MAR. 23, 2022, at A1, A7.

13. *Id.*

> nition of each other's authority and responsibilities, because conflicts can damage the intellectual integrity and reputation of the journal and its financial success.[14]

The Journal remains atop Washington and Lee's annual rankings of the nation's nineteen scholarly journals covering energy and natural resources law. Editorial independence has served the Journal and EBA membership well.

We hope you'll enjoy the thought-provoking contents of this edition. And let us hope that the next six months are happier than the last six. The Detroit Tigers won their home opener, their future Hall-of-Famer, Miguel Cabrera, joined Hank Aaron and Willie Mays as the only players in Major League Baseball history to hit 500 homeruns, collect 3000 hits and have a lifetime batting average above .300, the Detroit Pistons' Cade Cunningham finished third in the balloting for NBA Rookie of the Year and Detroit Red Wings' Moritz Seider is the leading candidate for the NHL's rookie of the year award. So that's a start . . .

Harvey L. Reiter
Washington DC
May 2022

14. Mary E. Northrdige, et al., *Editorial independence at the journal,* 95 AM. J. PUB. HEALTH 377, 377-99 (2005) (quoting World Association of Medical Editors, WAME Policy Statements), *available at* https://www.ncbi.nlm.nih.gov/pmc/articles/PMC1449185/.

IN MEMORIAM: ROBERT (BOB) A. O'NEIL

Robert (Bob) A. O'Neil, a longtime practitioner before the Federal Energy Regulatory Commission, died after a brief illness on January 7, 2022. For more than forty years, he served public power and member-owned utilities, negotiating numerous transactions to ensure low cost and reliable power for his clients and their retail members. He helped to shape national electric energy policies on electric transmission access and deregulation, especially the Regulatory Fairness Act of 1988 on which he testified in Congress.

Bob was a proud Bostonian who, after matriculating at the Boston Latin School, went on to obtain his undergraduate degree and law degree from Boston College. Bob began his legal career in the Judge Advocate General's Corps of the U.S. Army, International Law Division, and spent several years stationed in Japan (laying the ground for some of his best stories).

In 1980, Bob was a founding principal of Miller, Balis & O'Neil, which became the Washington office of McCarter & English in 2014. He was a tough negotiator with a wicked sense of humor. He was good at math, and he had vision. He gave all new attorneys at the firm a reverse polish notation (RPN) HP-12C calculator and then quizzed them on the inch-thick operating manual. Nicked and scratched, most of those calculators survive today. In 1988, Bob steered his small law firm to be one of the first to have personal computers on attorney desks. Of course that investment proved to be a cost-savings move, one of many that he implemented. Most famously, he purchased a second-hand PBX phone system from a bankrupt hotel to handle the firm's telecommunications for more than a decade. Other ideas were less spectacular. All this reflected incredible business acumen for a lawyer. He often attributed this talent to his part-time job keeping the books for a hotel while in law school.

He was devoted to the wellbeing of his law firm family as well as his nuclear family, leaving behind his wife Barbara of 45 years, a son and a daughter who each are practicing attorneys, and five grandchildren.

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FERC'S AUTHORITY TO REGULATE HYDROGEN PIPELINES UNDER THE INTERSTATE COMMERCE ACT

William G. Bolgiano[*]

Synopsis: As recognized in the recent infrastructure bill, hydrogen and hydrogen pipelines will play an important role in the economy as we strive to slow and reverse climate change. This article seeks to determine how hydrogen pipelines can or should be regulated. It proposes that the Federal Energy Regulatory Commission (FERC) has the authority to regulate the transportation of hydrogen by pipeline under the Interstate Commerce Act (ICA), which governs FERC's regulation of pipelines carrying crude oil, refined petroleum products, and natural gas liquids. Separately, FERC can regulate the transportation of blends of hydrogen and natural gas under the Natural Gas Act (NGA)—and pipelines can employ capacity leases to keep clear when the latter becomes the former.

America's pipeline regulatory regime is comprehensive, covering the transportation of all commodities other than water. Any non-water pipeline will fall under one of three regulatory regimes: (1) the NGA administered by FERC; (2) the ICA administered by FERC; or (3) the Interstate Commerce Commission Termination Act (ICCTA) administered by the Surface Transportation Board (STB). This article proposes a test to determine how pipelines are regulated depending on what they carry.

This article surveys the legislative history and precedent to distill a test delineating jurisdiction between the three conterminous regimes that govern the transportation of different commodities by pipeline. The NGA governs pipelines carrying naturally occurring methane and mixtures of naturally occurring methane and other commodities, including manufactured methane. The ICA governs pipelines carrying petrochemicals with potential energy uses and their renewable substitutes. And finally, ICCTA governs pipelines carrying any remaining commodity other than water and manufactured methane. Pipelines carrying water and purely manufactured methane are the only interstate pipelines not subject to federal economic regulation. In constructing this test, this article identifies which regime applies to pipelines carrying biomethane, liquid biofuels, and carbon dioxide.

The article then applies this pipeline commodities jurisdictional test to hydrogen-based on a detailed factual analysis of its current origins from fossil fuels, its potential generation from renewable sources, and its current and future

* Mr. Bolgiano is an associate in Venable LLP's energy group. He owes each member of that group a great deal of thanks for their support and encouragement in this work and for the valuable experience, knowledge, and opportunities that enabled it. A particular debt of gratitude is owed to his mentor, Matthew Field, who provided substantial support and guidance and collaborated on earlier work on this topic. The view's expressed are only the author's and should not be taken as legal advice.

energy uses, particularly in petroleum and biofuel refining. Applying this test to hydrogen shows that FERC can regulate the introduction of hydrogen into a natural gas pipeline under its NGA authority. More importantly, this article contends FERC has authority over pipelines transporting pure hydrogen under the ICA equivalent to its authority over pipelines carrying oil, refined petroleum products, and ethane and other natural gas derivatives used for energy. Hydrogen from renewable sources would also be subject to FERC's ICA regulation under authority analogous to its jurisdiction over pipelines carrying ethanol.

Hydrogen has the exciting potential to power crucial sectors of the economy where other renewables cannot stack up. It is also needed to make renewable hydrocarbons, to grow our food, and even to power nuclear fusion. Every liquid fuel (conventional or renewable) almost certainly contains hydrogen that was obtained by a refiner in its pure form. Hydrogen made from renewable resources can be most efficiently transported by pipeline and there is a growing consensus that a new hydrogen pipeline network will be needed. Hydrogen pipelines are generally considered subject to STB regulation. However, FERC would be the more appropriate and abler regulator, and its more developed body of ICA precedent would provide greater regulatory certainty. The urgent need to adopt renewable fuels calls for unprecedented levels of technological, economic, and societal adaptation. In this narrow world of pipeline law, we are fortunate to have a regulatory regime that is up to the task. A better understanding of the federal pipelines regulatory regime can chip away at the uncertainty holding back investment in renewable infrastructure as well as provide the means to protect emerging consumer interests.

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I. INTRODUCTION

This article explores how—if at all—hydrogen pipelines might be regulated. To do this it first tries to answer the question: how are pipelines regulated based on the product they carry? Answering this question also provides significant insight into how pipelines carrying other renewable energy commodities should and can be regulated. The article focuses on hydrogen because hydrogen pipelines face the greatest amount of regulatory uncertainty and placing them within the jurisdictional framework requires a deeper analysis with broader implications. In addition, it is growing increasingly clear that renewable hydrogen is needed to transition the economy from fossil fuels.

To place hydrogen within the pipeline regulatory framework, that framework first must be identified. This question—how pipelines are regulated depending on the commodity—does not appear to have been addressed in the academic literature before now. Because this has not yet been done, the article begins by articulating a test to determine how pipelines are regulated based on the commodity they carry. This article begins with a survey of the relevant legislative history from the Hepburn Act of 1906 through the Interstate Commerce Commission Termination Act (ICCTA) passed in 1995. The statutes establish that pipelines carrying any commodity besides water will fall under one, and only one, of three regulatory regimes:

(1) the Natural Gas Act[1] administered by the Federal Energy Regulatory Commission;

(2) the Interstate Commerce Act[2] administered by the Federal Energy Regulatory Commission; or

(3) the Interstate Commerce Commission Termination Act[3] administered by the Surface Transportation Board.

Since the passage of the Natural Gas Act (NGA) in 1938, transportation of all commodities (besides water) by interstate pipelines has been subject to federal regulation under one of two (and later three) regimes. Regulatory responsibility over these pipelines has been shuffled among various agencies, but the jurisdictional scope has never shrunk. Because these pipeline regimes are comprehensive and conterminous, any commodity must fall somewhere among them.

To determine more precisely which regime applies to pipelines carrying different commodities, the article then surveys the precedent delineating jurisdiction between these three regimes. It then identifies the questions and answers needed to place a commodity in a particular regime. In doing so, the article illustrates how this framework applies to three renewable energy commodities: biomethane, drop-in liquid biofuels, and carbon dioxide. The rule distilled is as follows. Pipelines carrying water and pure synthetic methane are unregulated.[4] Pipelines carrying naturally occurring methane, including in mixtures with synthetic methane or other elements, are subject to the NGA. Pipelines carrying en-

1. *See generally* 15 U.S.C. §§ 717-717z (2022).
2. *See generally* 49 U.S.C. app. §§ 1-27 (1988).
3. *See generally* 49 U.S.C. §§ 10101-16106 (2022).
4. This article is concerned with economic regulation of pipeline transportation at the federal level. That is, regulation of the terms, rates, and availability of transportation such as by the NGA, the ICA, and ICCTA. When this article uses the term "unregulated," therefore, it is referring the absence of federal economic regulation. An "unregulated" pipeline may, for instance, still be subject to regulation by the Pipeline and Hazardous Materials Safety Administration or subject to state economic regulation but that is beyond the scope of this article.

ergy petrochemicals and their non-petrochemical substitutes are regulated under the Interstate Commerce Act (ICA). Pipelines carrying everything else would be subject to ICCTA administered by the Surface Transportation Board (STB). The article briefly states the different ramifications of these different regimes, with a focus on the different scopes of jurisdiction.

Finally, the article applies the framework to hydrogen and concludes that the transportation of hydrogen by pipeline is most appropriately regulated under the ICA as administered by FERC (rather than under ICCTA administered by the STB), while the transportation of a mix of hydrogen should be subject to the NGA, also administered by FERC.[5] This conclusion is compelled by detailed application of the relevant facts precedent to as well as broader adherence to the purpose underlying the statutes. Specifically, hydrogen is not methane, though it can be blended with methane and is largely derived from it. Further, hydrogen used today is largely derived from petroleum sources and has numerous energy applications, and hydrogen derived from renewable sources will continue to compete directly with fossil-derived fuels. As a practical matter, FERC would be also the more appropriate, and abler, regulator of hydrogen pipelines and could better foster their development.

II. THE NEED FOR HYDROGEN, HYDROGEN PIPELINES, AND RENEWABLE PIPELINE REGULATION

Hydrogen is often called the "swiss army knife of decarbonization."[6] But this analogy only tells half the story. For many industries, hydrogen is not just one of many available tools to replace fossil fuels, but is rather the only proven option. This is especially true for numerous essential and carbon-intense sectors of the economy that have proven stubbornly difficult to decarbonize. The resource was singled out with its own section in Congress's recent infrastructure spending bill.[7] Hydrogen is also essential to producing biofuel, so it will remain crucial even if biofuels are chosen over hydrogen fuel cells for certain sectors, such as aviation. Clean hydrogen, unlike conventional hydrogen, will require pipelines to transport economically. Currently, there is perceived regulatory uncertainty regarding hydrogen pipelines, which must be resolved to encourage investment in this infrastructure that will soon be essential. This article aims to chip away at that uncertainty.

5. The article also proposes that capacity leases could be employed when needed to delineate the former from the latter.

6. *See, e.g.*, HYDROGEN: A CLEAN SOLUTION TO HEAVY-DUTY DIESEL TRANSPORTATION 1 (Dec. 14, 2021), https://www.lexology.com/library/detail.aspx?g=f31dfaf4-906d-48e6-ba75-96f4e288c11a; Abby Smith, *Biden administration and industry alike see hydrogen as 'Swiss Army knife' for eliminating emissions*, WASH. EXAM'R (Apr. 15, 2021), https://www.washingtonexaminer.com/policy/energy/biden-administration-and-industry-alike-see-hydrogen-as-swiss-army-knife-for-eliminating-emissions.

7. Infrastructure Investment & Jobs Act §§ 40311-40314, Pub. L. No. 117-58, 135 Stat. 429, 1,005-15 (2021) (codified at 42 U.S.C. §§ 16151-16166) (Subtitle B—Hydrogen Research and Development) [hereinafter Infrastructure Act].

A. *Sources of Hydrogen*

Hydrogen, the most abundant element in the universe, is unique among energy carriers in terms of its diversity of potential sources. These are often described in terms of the so-called "rainbow" of hydrogen that categorizes the resource by its origin in terms of environmental impact. For instance, hydrogen made from splitting water molecules with wind or solar electricity is "green" whereas hydrogen made by reforming methane and releasing the carbon dioxide is "gray."[8] This article eschews the "rainbow" labelling because the pipeline jurisdictional test does not care about carbon intensity. Rather, it is primarily concerned with whether or not the product is a petroleum derivative.

1. Fossil Sources of Hydrogen

Despite its potential as a renewable fuel, hydrogen today is primarily produced from natural gas through a process called steam methane reforming. Methane—the essential component of natural gas—is composed of one carbon and four hydrogen atoms (CH_4). In steam methane reforming, steam (H_2O) is added to methane in the presence of heat and a catalyst, producing hydrogen (H_2) and carbon monoxide (CO) which is turned into carbon dioxide (CO_2).[9] These carbon oxides are usually released freely, contributing to climate change. Hydrogen can also be extracted from coal. Hydrogen derived from natural gas through steam methane reforming is called "gray" hydrogen and hydrogen derived from coal is called "brown" hydrogen.[10]

a. Low Carbon Fossil Options

Hydrogen can also be extracted from fossil fuels while producing fewer greenhouse gases. The recent Infrastructure Act specifically recognizes this and in fact mandates that one of four proposed "hydrogen hubs" be based on the production of hydrogen from fossil fuels.[11] The bill also prioritizes hydrogen projects in natural gas producing regions.[12] The most straightforward method of limiting emissions is employing conventional steam reforming of methane while also capturing and sequestering the carbon dioxide. This is called "blue" hydrogen.[13] There are other methods as well. For instance, with methane pyrolysis,

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8. U.S. ENERGY INFO. ADMIN., HYDROGEN EXPLAINED, PRODUCTION OF HYDROGEN, https://www.eia.gov/energyexplained/hydrogen/production-of-hydrogen.php. Hydrogen made from biomass or waste or reformed from biomethane is usually considered "green" hydrogen as well.

9. U.S. DEP'T OF ENERGY, HYDROGEN PRODUCTION: NATURAL GAS REFORMING, https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.

10. WHITE & CASE LLP, GLOBAL HYDROGEN GUIDE: EMERGING POLICY AND REGULATORY INITIATIVES 3 (2021).

11. Infrastructure Act § 40314, 135 Stat. at 1,008-10 (codified at 42 U.S.C. § 16161a).

12. *Id.*, 135 Stat. at 1,009 (codified at 42 U.S.C. § 16161a(c)(3)(D)). The bill also authorized grants for the Appalachian Regional Commission to "establish a regional energy hub in the Appalachian region for natural gas and natural gas liquids, including hydrogen produced from the steam methane reforming of natural gas feedstocks." *See id.* § 11506, 135 Stat. at 584 (codified at 40 U.S.C. §§ 14102-14704).

13. The climate impact of this has been the subject of much scrutiny, with one study finding that blue hydrogen could be worse for the climate than burning methane. *See* S&P GLOBAL PLATTS, *New study questions*

the methane is heated until it is separated into hydrogen and solid carbon (which also has economic value).[14] This is called "turquoise" hydrogen to distinguish it from (less green) "blue" hydrogen. And, of course, new technologies are continually being developed.[15]

2. Renewable Sources of Hydrogen

Hydrogen can also be obtained from myriad renewable sources.[16] This is, after all, what is driving all the recent interest in hydrogen as an energy carrier. Some green methods of producing hydrogen are even carbon negative. Currently, "green" hydrogen is more expensive to produce than conventional fossil hydrogen, but that cost is steadily declining.[17] In fact, Biden's Department of Energy has made reducing the price of green hydrogen by 80% the subject of its inaugural "Earthshot."[18]

a. Biomass

Hydrogen can be made from biomass, including biomethane.[19] The most attractive feature of biomass hydrogen is that it should theoretically be carbon negative when more carbon is captured than released.[20] Some companies hope to market carbon-neutral or even carbon-negative hydrogen from natural gas by mixing enough biomethane into the feedstock to offset the carbon that is not captured.[21]

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climate sense of blue hydrogen in UK strategy (Aug. 12, 2021), https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081221-new-study-questions-climate-sense-of-blue-hydrogen-in-uk-strategy.

14. *See* S&P Global Platts, *Bill Gates-backed startup to build 'turquoise hydrogen' pilot by end of 2022* (Jul. 7, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/bill-gates-backed-startup-to-build-turquoise-hydrogen-pilot-by-end-of-2022-65354106, interestingly this was known to Congress around the time it was considering how to regulate gas pipelines. *See* Report No. 84-A at 48 ("other uses of natural gas as a raw material") (discussed infra).

15. *See, e.g.*, Leigh Collins, *We will make zero-CO2 hydrogen from natural gas so cheaply we could give it away for free*, (Sept. 30, 2021), https://www.rechargenews.com/energy-transition/-we-will-make-zero-co2-hydrogen-from-natural-gas-so-cheaply-we-could-give-it-away-for-free-/2-1-1075224.

16. In addition, there is the (yet unproven) potential to gather hydrogen from naturally occurring reservoirs, sometimes called "white" hydrogen. *See* Bella Peacock, *Natural hydrogen exploration 'boom' snaps up one third of South Australia*, PV MAG. (Feb. 2, 2022), https://www.pv-magazine.com/2022/02/02/natural-hydrogen-exploration-boom-snaps-up-one-third-of-south-australia/.

17. *Hydrogen Shot*, U.S. DEP'T OF ENERGY, HYDROGEN & FUEL CELL TECH. OFF. (2021) https://www.energy.gov/eere/fuelcells/hydrogen-shot.

18. *Id.*

19. RAFAEL LUQUE, CAROL KI LIN, KAREN WILSON, & JAMES CLARK, HANDBOOK OF BIOFUELS PRODUCTION: PROCESSES AND TECHNOLOGIES (Woodhead Publ'g, 2d ed. 2016), (Chapter 15 "Production of bio-syngas and bio-hydrogen via gasification").

20. *Clean Hydrogen & Negative CO_2 Emissions*, NAT'L ENERGY TECH. LAB'Y, https://netl.doe.gov/coal/gasification/negative_ghg_emissions.

21. Leigh Collins, *We will make zero-CO2 hydrogen from natural gas so cheaply we could give it away for free*, RECHARGE NEWS (Sept. 30, 2021), https://www.rechargenews.com/energy-transition/-we-will-make-zero-co2-hydrogen-from-natural-gas-so-cheaply-we-could-give-it-away-for-free-/2-1-1075224; Shayne Willette, *Don't Forget About Biomass Gasification For Hydrogen*, FORBES (Apr. 22, 2022), https://www.forbes.com/sites/pikeresearch/2020/04/22/dont-forget-about-biomass-gasification-for-hydrogen/?sh=3f581413724f.

b. Electrolysis of Water

The quintessential "green" hydrogen is produced by the electrolysis of water powered with renewable electricity. In this method, renewable electricity is used to split water molecules (H_2O) into hydrogen and oxygen.[22] So-called "pink" hydrogen is made by electrolyzing water with nuclear energy.[23] In theory, this "green" hydrogen can be generated anywhere with access to renewable electricity and water. However, most agree that economies of scale will support concentrating production of green hydrogen where renewable electricity is cheapest and then transporting the hydrogen by pipe to where it will be consumed.[24] The alternative would be to transmit the renewable energy by cable to the point of water electrolysis, which would be more expensive and would also burden the existing electrical grid.[25] Therefore, hydrogen pipelines will become increasingly relevant as hydrogen is increasingly sourced from wind, solar, or nuclear sources.

B. Uses of Hydrogen

Just as hydrogen can be derived from numerous sources, it also has many applications. While fossil energy is the dominant use of hydrogen today, with renewable energy likely being the dominant use in the future, hydrogen also has many smaller, but essential non-energy applications. Hydrogen will remain needed in all these sectors after the transition from fossil sources to renewable ones.

1. Current Uses of Hydrogen

Numerous sectors of the economy rely on hydrogen. Currently, hydrogen's primary use is in the energy sector as an important input to fossil and renewable hydrocarbon fuels. Its second biggest use is in agriculture, where it used to grow half the world's food.[26] It also has other smaller, yet essential, applications.

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22. *Hydrogen Production: Electrolysis*, U.S. DEP'T OF ENERGY, HYDROGEN & FUEL CELL TECH. OFF., https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.

23. *The hydrogen colour spectrum*, NAT'L GRID, https://www.nationalgrid.com/stories/energy-explained/hydrogen-colour-spectrum.

24. *See* HYDROGEN COUNCIL AND MCKINSEY & CO., HYDROGEN INSIGHTS: A PERSPECTIVE ON HYDROGEN INVESTMENT, DEPLOYMENT AND COST COMPETITIVENESS 20 (Feb. 2021), https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021.pdf ("Hydrogen pipelines can effectively transport renewable hydrogen across long distances. They can transport 10 times the energy at one-eighth the cost associated with electricity transmission lines. Furthermore, hydrogen pipelines have a longer lifespan than electricity transmission lines and offer dual functionality, serving as both a transmission and storage medium for green energy"); *see also* Joshua D. Rhodes et al., White Paper, *Renewable Electrolysis in Texas: Pipelines versus Power Lines*, ENERGY INSTITUTE, THE UNIV. OF TEX. AT AUSTIN (2019), https://sites.utexas.edu/h2/files/2021/08/H2-White-Paper_Hydrogen-Pipelines-versus-Power-Lines.pdf (concluding that pipelines would be preferred even for movements across Texas).

25. HYDROGEN COUNCIL & MCKINSEY, *supra* note 24; Joshua D. Rhodes et al., *supra* note 24.

26. *See* discussion below in section VI.B.2.a.(i)-(iii).

a. Energy (Refining)

Every time we power an internal combustion engine with any sort of ubiquitous liquid fossil fuel, we are almost certainly also burning hydrogen that was at one point acquired by a refinery in its pure form. Refineries are by far the largest consumers of hydrogen today.[27] Importantly for our purposes, refiners use hydrogen for both its chemical *and* its energy properties. In fact, most hydrogen acquired by refiners is meant to become part of fuel that is eventually burned in internal combustion engines and jets. Hydrogen is directly essential to two key operations of refineries: hydrocracking (upgrading) and hydrotreating (removing impurities). In hydrocracking hydrogen is used to "upgrade" heavier products by joining hydrogen with split, or "cracked," hydrocarbon molecules, making them lighter. In hydrotreating, hydrogen is used to remove "heteroatom," impurities, primarily sulfur. For instance, to remove sulfur, refiners split molecules that contain sulfur and use some of the hydrogen to bond with the sulfur (to enable its removal in the form of hydrogen sulfide, H_2S) and some of the hydrogen to increase the hydrogen content of the remaining hydrocarbon molecules.[28] In this way, the typical car-owner is as much a consumer of hydrogen, as they are a consumer of crude oil. The specific facts of these refining operations are discussed in more detail in the section applying FERC's jurisdictional test to hydrogen.[29]

b. Agricultural & Other

In addition to the energy sector, hydrogen has numerous other essential uses. For instance, half of humanity's food is grown with the aid of ammonia fertilizer (NH_3) made with hydrogen.[30] This is the second largest application of hydrogen (though it is still dwarfed by refining).[31] In fact, the production of ammonia alone accounts for 1% of worldwide emissions.[32] Of note, there is already a large interstate ammonia pipeline network regulated by the STB. Hydrogen has other uses in the chemical and industrial sectors and is also used in laboratories. These consume a relatively small share of all hydrogen produced, but that hydrogen is nevertheless crucial and irreplaceable in those sectors. Demand for hydrogen in all these sectors will continue well past the transition from fossil fuels.

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27. ENERGY FUTURES INITIATIVE, THE FUTURE OF CLEAN HYDROGEN IN THE UNITED STATES: VIEWS FROM INDUSTRY, MARKET INNOVATORS, AND INVESTORS 21 (Sept. 2021), available for download at https://energyfuturesinitiative.org/reports/the-future-of-clean-hydrogen-in-the-united-states/.

28. *See* discussion below in section VI.B.2.

29. *See* discussion below in section VI.B.2.a.(i)-(iii).

30. *See* Leigh K. Boerne, *Industrial ammonia production emits more CO2 than any other chemical-making reaction. Chemists want to change that*, CHEMISTRY & ENG'G NEWS, (June 15, 2019), https://cen.acs.org/environment/green-chemistry/Industrial-ammonia-production-emits-CO2/97/i24.

31. ENERGY FUTURES INITIATIVE, *supra* note 27, at 21.

32. Robert F. Service, *New reactor could halve carbon dioxide emissions from ammonia production*, AM. ASS'N FOR THE ADVANCEMENT OF SCI. (Nov. 6, 2019), https://www.science.org/content/article/new-reactor-could-halve-carbon-dioxide-emissions-ammonia-production.

2. Uses of Hydrogen in a Net Zero Economy:

Consensus is building that hydrogen will play an important part in a net-zero economy. The recent Infrastructure Act correctly identifies that hydrogen "provides economic value and environmental benefits for diverse applications across multiple sectors of the economy."[33] Hydrogen can be perfectly clean and is uniquely versatile. It can power an electric fuel cell where the only emission is clean water, or it can be burned for heat and produce only water vapor and some nitrogen oxides. It can supply power wherever electric or thermal energy are needed. Hydrogen is a less efficient energy carrier than most batteries, so its most promising applications are where electrification via batteries is not feasible.[34] These industries include aviation, maritime shipping, mining, long-distance and heavy-duty transportation. It also includes heavy industrial sectors such as steel and concrete production that need high temperature that cannot be generated by electricity at all. In addition, hydrogen would still be irreplaceable in all its current applications, including non-energy applications, after the transition from fossil fuels.[35]

a. Increased Hydrogen Demand for Refining Biofuels

In some industries, such as aviation, there is a debate as to whether hydrogen or biofuels will take over from fossil fuels.[36] But hydrogen would still be needed to refine those biofuels. In fact, more hydrogen is needed to refine biofuels than to refine petroleum.[37] The exact mechanics are described further be-

33. Infrastructure Act § 40311, 135 Stat. at 1,006 (Congressional findings).

34. *See* Leigh Collins, *IPCC report: Clean hydrogen needed for net zero, but only where green electric solutions not feasible*, RECHARGE NEWS (Apr. 6, 2022) (discussing IPCC, MITIGATION OF CLIMATE CHANGE (2022)); HYDROGEN COUNCIL & MCKINSEY, *supra* note 24, at 26 (Exhibit 17, "Hydrogen competitiveness per end application in 2030").

35. *See* AMGAD ELGOWAINY ET AL., ARGONNE NAT'L LAB., ASSESSMENT OF POTENTIAL FUTURE DEMANDS FOR HYDROGEN IN THE UNITED STATES (2020) [hereinafter H2@SCALE].

36. *See, e.g.*, Hugo del Campo, et al., *The sky is the limit Perspectives on the emerging European commercial aircraft value chain recovery and beyond*, MCKINSEY & CO. (Oct. 20, 2021), https://www.mckinsey.com/industries/aerospace-and-defense/our-insights/the-sky-is-the-limit-perspectives-on-the-emerging-european-commercial-aircraft-value-chain-recovery-and-beyond?cid=other-pso-lkn-mip-mck-oth-2110&li_fat_id=80ddce9d-da08-49db-bd30-bd33aa31438f ("For narrow-body aircraft and regional jets, only about 50 percent believe SAF will dominate, while the other half see hydrogen as the dominant new sustainable fuel."). Another such industry is heavy trucking. *See* Jack Ewing, *Truck Makers Face a Tech Dilemma: Batteries or Hydrogen?* N.Y. TIMES (Apr. 11, 2022), https://www.nytimes.com/2022/04/11/business/electric-hydrogen-trucks.html; William Boston, *The Electric-Truck Battle to Come: Batteries Versus Hydrogen Fuel Cells*, WALL ST. J. (Nov. 9, 2021), https://www.wsj.com/articles/the-electric-truck-battle-to-come-batteries-versus-hydrogen-fuel-cells-11636466414.

37. U.S. DEP'T OF ENERGY, OFF. OF ENERGY EFFICIENCY & RENEWABLE ENERGY, SUSTAINABLE AVIATION FUEL: REVIEW OF TECHNICAL PATHWAYS 33 (2020), https://www.energy.gov/sites/prod/files/2020/09/f78/beto-sust-aviation-fuel-sep-2020.pdf ("Hydrogen demand is required for all routes (hydrocracking large molecules, building up small molecules, or saturating direct fermentation molecules)"); *id.* at 47 ("Hydrogen demand is high for all biofuels and unusually high for [sustainable aviation fuel]"); IEA, BIOENERGY, 'DROP-IN' BIOFUELS: THE KEY ROLE THAT CO-PROCESSING WILL PLAY IN ITS PRODUCTION (2019), https://www.ieabioenergy.com/wp-content/uploads/2019/09/Task-39-Drop-in-Biofuels-Full-Report-January-2019.pdf ("The important role of hydrogen in upgrading biological feedstocks was emphasised as a key challenge for the future development of drop-in biofuels. This is even more pertinent now, particularly finding cheap and renewable sources of hydrogen").

low,[38] but hydrogen is needed both for removing impurities and for upgrading the product wherein the hydrogen becomes a part of the hydrocarbon "drop-in" fuels that are compatible with existing engines. Even without clean hydrogen mandates, voluntary demand for clean hydrogen to make clean fuels has already created market opportunities.[39]

b. Combusted for Thermal Energy

Many promising applications of renewable hydrogen would involve combusting it for its direct heat, much like how natural gas is used today. This would be particularly important in heavy industries that require high temperatures that cannot be achieved with electrification. For example, glass, steel, and cement are all vital to our modern life—and are all needed to build our post-fossil fuel infrastructure. These industries account for a large share of industrial emissions, which is growing with increasing demand for these commodities. Hydrogen is seen as the most promising means of decarbonizing these sectors.[40]

Traditional utilities and power suppliers have also expressed great interest in hydrogen as a means of decarbonizing gas turbine power plants and even home gas distribution.[41] Using hydrogen or mixing hydrogen with natural gas to power a turbine generator would provide another means of transmitting and, importantly, storing of renewable energy. Many utilities are actively exploring this strategy, notably the Intermountain Power Project in Utah.[42]

c. Fuel Cell Energy

Hydrogen can also produce electric power when run through a fuel cell. In this way, hydrogen functions much like a battery, but with an importantly different set of weaknesses and strengths compared to lithium and other batteries. Like lithium batteries, hydrogen fuel cells are quiet and easy to maintain.[43] However, fuel cells are significantly less efficient at converting the energy used to split water molecules back into electricity, although this technology is improving.[44] So hydrogen is not preferred over batteries where batteries are feasible.

38. *See* discussion below in sections VI.B.2.a.(i)-(iii).

39. Camila Naschert, *Biofuel's thirst for green hydrogen opens new market for utilities*, S&P GLOBAL (Feb. 10, 2021), https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/biofuel-s-thirst-for-green-hydrogen-opens-new-market-for-utilities-62406439. For instance, a planned green hydrogen project centered on the Piedras Pintas salt dome in Duval County, Texas ("Hydrogen City") seeks to supply hydrogen as a feedstock for sustainable aviation fuel, in addition to ammonia, rocket fuel, and hydrogen fuel for power plants. *See* GREEN HYDROGEN INT'L CORP., PROJECTS: HYDROGEN CITY, TEXAS, https://www.ghi-corp.com/projects/hydrogen-city.

40. CHRIS BATAILLE, OECD, LOW AND ZERO EMISSIONS IN THE STEEL AND CEMENT INDUSTRIES: BARRIERS, TECHNOLOGIES AND POLICIES 14 (2019).

41. *See* HYDROGEN COUNCIL & MCKINSEY, *supra* note 24, at 27.

42. *See* Steve Griffin, *Intermountain Power Project's switch from coal to hydrogen could power rural Utah job growth*, THE SALT LAKE TRIB. (Oct. 5, 2021), https://www.sltrib.com/news/environment/2021/10/05/intermountain-power/ *see also* https://www.ipautah.com/ipp-renewed/.

43. U.S. DEP'T OF ENERGY, DEPARTMENT OF ENERGY HYDROGEN PROGRAM PLAN 29 (2021).

44. COPENHAGEN CTR. OF ENERGY EFFICIENCY, ANALYSIS OF HYDROGEN FUEL CELL AND BATTERY EFFICIENCY 6 (2019).

But there are many carbon-intense sectors where batteries simply cannot be used because the weight of the required batteries proves prohibitive. Hydrogen—the lightest element there is—does not present this obstacle.[45] For instance, hydrogen is seen by many as the preferred long-term solution for decarbonizing aviation, maritime travel, long distance and heavy surface transportation, and heavy industrial applications such as powering construction and mining equipment.[46] While fuel cells do not generate their power directly from heat, they can generate a significant amount of heat which can even be sufficient to support cogeneration, making the system's efficiency more comparable to a lithium battery system.[47]

C. Clear Regulation Is Increasingly Needed for Pipelines Carrying Hydrogen and Other Renewable Commodities

Pipelines have become synonymous with fossil fuels and climate change.[48] However, pipelines will remain crucially relevant as the economy replaces fossil fuels with renewable energy commodities. Because not all sectors of the economy can be electrified, hydrogen or other 'green fuels' will be needed to replace carbon-intense fossil fuels.[49] And pipelines will remain the safest, cleanest, and most efficient means of transporting these liquid and gaseous commodities. Building a new pipeline, or converting an existing one, is a large and financially risky undertaking that must be backed by a degree of regulatory certainty. This article attempts to contribute as much certainty as it can, or at least begin the process of removing some uncertainty. First, this article describes how regulatory jurisdiction over pipelines is determined based on the commodity that pipeline carries. Second, this article provides an argument that FERC, the agency with the more relevant expertise and more developed body of pipeline precedent, can and should regulate hydrogen pipelines.

1. Increased Pipeline Demand for Green Hydrogen in All Scenarios

As hydrogen is increasingly derived from sources other than natural gas, dedicated hydrogen pipelines will increasingly become economically justified.[50] Even if biofuels are chosen over hydrogen fuel cells for every sector of the economy, refining these fuels will require much more hydrogen than we currently use to refine their fossil equivalents. And if this hydrogen is "green," dedicated pipelines will be the most efficient means of transporting it from sources of re-

45. *Id.* at 1.

46. *See* HYDROGEN COUNCIL & MCKINSEY, *supra* note 24 at 28; U.S. DEP'T OF ENERGY, DEPARTMENT OF ENERGY HYDROGEN PROGRAM PLAN 28 (2021).

47. *See* Order No. 874, *Fuel Cell Thermal Energy Output*, 173 FERC ¶ 61,226 at PP 8-9 (2021); U.S. DEP'T OF ENERGY, FUEL CELL TECH. OFFICE, FUEL CELLS 1 (2015), https://www.energy.gov/sites/prod/files/2015/11/f27/fcto_fuel_cells_fact_sheet.pdf.

48. *See, e.g.*, ANDREAS MALM, HOW TO BLOW UP A PIPELINE (2021) which, despite its proactive title, is not limited to pipelines.

49. *See* NEAL KISSEL, QUAN LI, & DRAKE HERNANDEZ, CRA MARAKON HYDROGEN MARKET PRIMER 2, CHARLES RIVER ASSOC. (Jul. 22, 2021), available for download at https://www.crai.com/insights-events/publications/hydrogen-market-primer/.

50. *See* HYDROGEN COUNCIL & MCKINSEY, *supra* note 24, at 29.

newable electricity to refineries, industrial centers, and other end-users. Importantly, pipeline transportation would not burden the electrical grid. In one sense, virtually all hydrogen used today is already transported by pipeline in the form of natural gas, some of which is turned into hydrogen. Dedicated pipelines for carrying pure hydrogen currently only measure 1,600 miles, concentrated in the Gulf Coast refining centers.[51] Much more hydrogen pipeline infrastructure will be needed to combat climate change on all fronts.[52]

a. Hydrogen Can Utilize Existing Natural Gas Pipeline Infrastructure

Natural gas pipeline infrastructure presents a twofold opportunity for renewable hydrogen. First, the existing natural gas pipeline network could support blends of hydrogen with little to no modification.[53] By most accounts, the existing grid can safely accept a hydrogen blend of up to 20 percent.[54] This approach is seen as especially attractive in the near term, before demand justifies dedicated hydrogen infrastructure.[55] In fact, FERC recently endorsed a pipeline's estimate of climate impacts that "account[ed] for the limited, eventual penetration of hydrogen and renewable natural gas into the natural gas supply."[56] Second, the repurposing natural gas pipelines for hydrogen transportation is seen as an attractive alternative to building new pipelines from whole cloth.[57] Such conversions could cut costs in half or more compared to new construction.[58] This could also be an attractive option for natural gas and other pipeline owners who do not want to be stuck with a "stranded" asset after the economy moves on from fossil fuels.[59] As will be discussed further below, conversion of a natural gas pipeline to another use does not only require regulatory certainty, it requires regulatory permission in the form of FERC authorization to abandon its current purpose.

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51. PAUL W. PARFOMAK, CONG. RSCH. SERV., PIPELINE TRANSPORTATION OF HYDROGEN: REGULATION, RESEARCH, AND POLICY 6 (2021) [hereinafter CRS REPORT].

52. INT'L ENERGY AGENCY, GLOBAL HYDROGEN REVIEW 144 (2021), https://iea.blob.core.windows.net/assets/3a2ed84c-9ea0-458c-9421-d166a9510bc0/GlobalHydrogenReview2021.pdf.

53. *Id.* at 145-46; ENERGY FUTURES INITIATIVE, *supra* note 27, at 43 ("Blending hydrogen in natural gas pipelines is the most active area of investigation in the transport and storage value chain segment").

54. HYDROGEN COUNCIL & MCKINSEY, *supra* note 24, at 21; H2@SCALE, *supra* note 35, at 43-44; *see* M. W. MELAINA, O. ANTONIA, & M. PENEV, NAT'L RENEWABLE ENERGY LAB., BLENDING HYDROGEN INTO NATURAL GAS PIPELINE NETWORKS: A REVIEW OF KEY ISSUES 32 (2013), https://www.nrel.gov/docs/fy13osti/51995.pdf ("If less than 20% hydrogen is introduced into distribution system, the overall risk is not significant for both distribution mains and service lines, but the service lines are more impacted than mains because they are mostly in confined spaces."). Without significant modifications though, most natural gas pipelines cannot handle much more hydrogen without encountering issues such as steel embrittlement.

55. For an example of how businesses are actively pursuing this transportation method, *see, e.g.*, Molly Burgess, *Linde starts up 'world's first' plant for extracting hydrogen from natural gas pipelines*, GAS WORLD (Jan 20, 2022), https://www.gasworld.com/linde-starts-up-worlds-first-plant-for-extracting-hydrogen-from-natural-gas-pipelines/2022557.

56. *Iroquois Gas Transmission Sys., L.P.*, 178 FERC ¶ 61,200 at P 56 (2022).

57. INT'L ENERGY AGENCY, *supra* note 52, at 147-48; CRS REPORT, *supra* note 52, at 7-8.

58. CRS REPORT, *supra* note 51, at 8.

59. *Id.* (citing ENV'T DEF. FUND, MANAGING THE TRANSITION PROACTIVE SOLUTIONS FOR STRANDED GAS ASSET RISK IN CALIFORNIA (2019)).

The recent Infrastructure Act instructs the Secretary of Energy to support hydrogen "transmission by pipeline, including retrofitting the existing natural gas transportation infrastructure system to enable a transition to transport and deliver increasing levels of clean hydrogen, clean hydrogen blends, or clean hydrogen carriers."[60] The Secretary's national hydrogen strategy must also identify "opportunities to use, and barriers to using, existing infrastructure, including all components of the natural gas infrastructure system."[61] Even more recently, the Biden administration expressed an intent to leverage increased U.S. natural gas exports to Europe into a longer-term position for the U.S. as an exporter of hydrogen.[62] As part of its plan to supply Europe with natural gas, the White House committed to collaborating with the European Union on the uses of hydrogen and to work to build "clean and renewable *hydrogen-ready* infrastructure."[63]

2. Investment in Pipelines Requires Regulatory Certainty

Bringing hydrogen pipelines into operation, whether new or converted, requires significant investment. Lack of regulatory certainty has already been identified as a barrier dampening investment in hydrogen pipeline infrastructure.[64] This article seeks to help fix that misconception. It does this first by answering the question of how pipelines are regulated depending on the commodity they carry. This question does not appear to have been addressed in any systematic method before. No doubt there will be refinements as the transition from fossil fuels gathers momentum, but this article hopes to move the discussion forward.

The research shows that the federal system of pipeline regulation is—in terms of commodities other than water—comprehensive. Interstate pipelines carrying any commodity (other than water) are regulated under one of three legal authorities. Therefore, once a pipeline determines how this framework applies to the commodity it carries, it can move forward on regulatory terra firma. FERC has already addressed the jurisdictional status of biomethane and liquid biofuels, although some questions remain.

The article next seeks to place hydrogen within the existing regulatory regime. Because hydrogen is not natural gas (*i.e.* methane), it falls under the framework of the Hepburn Act, which regulates everything other than water and

60. Infrastructure Act § 40313, 135 Stat. at 1,007 (codified at 42 U.S.C. § 16161a(e)(6)(A)).

61. *Id.* § 40314, 135 Stat. at 1,010 (codified at 42 U.S.C. § 16161b(a)(2)(I)).

62. Jennifer A. Dlouhy & David R. Baker, *Biden Eyes Long-Term Hydrogen Breakthrough in Plan to Send Gas to EU*, BLOOMBERG (Mar. 25, 2022), https://www.bloomberg.com/news/articles/2022-03-25/biden-eyes-long-term-hydrogen-breakthrough-in-plan-for-gas-to-eu.

63. WHITE HOUSE, FACT SHEET: UNITED STATES AND EUROPEAN COMMISSION ANNOUNCE TASK FORCE TO REDUCE EUROPE'S DEPENDENCE ON RUSSIAN FOSSIL FUELS (Mar. 25, 2022), https://www.whitehouse.gov/briefing-room/statements-releases/2022/03/25/fact-sheet-united-states-and-european-commission-announce-task-force-to-reduce-europes-dependence-on-russian-fossil-fuels/ (emphasis added).

64. ENERGY FUTURES INITIATIVE, *supra* note 27, at 41 (describing accounts from interviews with stakeholders that "[u]ncertain regulatory and market environments are deterring hydrogen pipeline investment" and that even "[s]ome companies are looking to hydrogen carriers and hydrogen-based alternative fuels to avoid regulatory issues for hydrogen pipelines"); James Bowe & William Rice, *Building the Hydrogen Sector Will Require New Laws, Regs*, LAW360 (January 13, 2021), https://www.law360.com/articles/1342390/building-the-hydrogen-sector-will-require-new-laws-regs.

gas under either ICCTA or the ICA. The two Hepburn Act statutes are largely similar in substance. Therefore, for hydrogen pipelines, the question is not *if*—or even really *how*—they are regulated at the federal level. The only serious question is *who* regulates them: FERC or the STB. The question of which agency governs, though, will likely be consequential to this emerging industry and clarity should be provided sooner rather than later.

3. FERC Can and Should Regulate Interstate Hydrogen Pipelines

Hydrogen is the only renewable pipelined commodity that is currently misplaced in the pipeline regulatory regime. Globally, hydrogen has been called a "jump ball," as it is uncertain which nations will gain the first mover advantage. At home, it is also a regulatory "jump ball" as the statute and precedent arguably empower either of two agencies—FERC or the STB—to regulate its transportation by pipeline. Hydrogen's myriad sources and applications make it a promising renewable fuel. This also makes the jurisdictional analysis for hydrogen pipelines more interesting, but answerable. The current understanding is that the handful of interstate hydrogen pipelines are regulated by the STB on the—mistaken—basis that hydrogen is a non-energy resource.[65] This interpretation might be permissible (if *Chevron* deference applies) but is ultimately unsound.

Hydrogen should be regulated by FERC under the ICA because it is used for energy purposes and derived from petroleum resources. This interpretation is consistent with FERC's articulation that because ammonia is made from hydrogen, ammonia pipelines would be subject to FERC's ICA jurisdiction if ammonia were used for energy purposes.[66] As described herein, hydrogen's current uses in refining are every bit as much of an energy source as the crude oil it is combined with. And hydrogen's future energy applications are myriad. FERC also exercises ICA jurisdiction over renewable substitutes for energy petrochemicals, so FERC would retain jurisdiction over renewable hydrogen not derived from fossil resources. And on a practical level, FERC is simply the better agency to regulate this emerging energy resource, especially with its experience overseeing the conversion of natural gas pipelines to ICA uses, as well as pipeline capacity leases. In this way, FERC asserting jurisdiction over hydrogen pipelines under the ICA would provide a greater degree of regulatory certainty for those interested in developing or using hydrogen pipelines.

III. DEVELOPMENT OF THE PIPELINE REGULATORY FRAMEWORK

To understand how hydrogen fits within the pipeline regulatory framework, we must begin with the framework's inception. Since this topic has not been ad-

65. *See* CRS REPORT, *supra* note 51, at 10 ("Jurisdiction over rates for interstate hydrogen pipelines resides with the Surface Transportation Board (STB)."); *Statement Regarding a Coordinated Framework for Regul. of a Hydrogen Econ.*, 72 Fed. Reg. 609, 618 (U.S. Dep't of Transp., Jan. 5, 2007) [hereinafter Hydrogen Economy Statement] ("The statement recognizes that the Surface Transportation Board (STB), the Federal economic regulator of railroads, also regulates economic aspects of interstate hydrogen pipelines"); GOV'T ACCOUNTABILITY OFF., ISSUES ASSOCIATED WITH PIPELINE REGULATION BY THE SURFACE TRANSPORTATION BOARD, app. I (1998) [hereinafter GAO REPORT]; *see also* discussion below in section VI.

66. *See Gulf Cent. Pipeline Co.*, 50 FERC ¶ 61,381 (1990); CF Indus., Inc. v. FERC, 925 F.2d 476, 478 (D.C. Cir. 1991). *See also* discussion below in sections III.C.2.a-b and VI.B.1-3.

dressed before, this article provides a thorough history. The regulatory framework grew over more than a century with little coordination between the numerous congresses, multiple presidents, four agencies (half of which don't exist anymore), and courts all interpreting relatively broad and general language. While its development may appear somewhat messy or unguided, its key elements have remained remarkably constant, and the resulting jurisdictional test is clear and manageable.

The statutory foundation and agency precedent provide guidance as to how this framework can and should be applied to emerging fuels. Most importantly, the statutes and precedent tell us the pipeline regulatory framework is virtually comprehensive, covering every commodity except water. There are three pipeline regulatory regimes, which can be better understood as two regulatory paradigms, one of which is split between two agencies. The Natural Gas Act (NGA) paradigm extensively regulates the more narrowly defined (but also more numerous) set of pipelines. The Hepburn Act common carrier paradigm governs all other pipelines, with the Federal Energy Regulatory Commission (FERC) administering petrochemical energy pipelines and the Surface Transportation Board (the STB) regulating all others.[67]

A. Statutory Foundation and Legislative History of the Federal Pipeline Regulatory Framework

The legislative history of the pipeline regulatory framework is crucial to understanding how it may be applied by agencies to hydrogen and other emerging renewable energy commodities. This history reveals two key facts about the federal pipeline regulatory regime. First, the regime is comprehensive. Since 1938, interstate pipelines transporting every commodity besides water have been regulated. Therefore, the question is how—not if—pipelines carrying new commodities will be regulated. The second fact is that Congress drew clear distinctions between these regulatory regimes. But those distinctions were all made against the backdrop of a fossil fuel economy, making it difficult to tell where one regime ends, and another takes its place, in a post-fossil fuel economy. Still, one regulatory regime must apply, and the statutes and Congressional intent are the first place to determine where those lines should be drawn.

Federal pipeline regulation began in 1906. In that year, driven by outrage at Standard Oil's monopoly, Congress passed the Hepburn Act, bringing oil pipelines under the jurisdiction of the Interstate Commerce Commission (the ICC) through the Interstate Commerce Act (the ICA). However, the Hepburn Act explicitly went beyond oil and regulated all pipelines besides those carrying water and artificial or natural gas. Congress put off regulating gas pipelines until 1938, when it passed the Natural Gas Act (NGA) and charged the Federal Power Commission (FPC) with regulating pipelines carrying natural gas and artificial

67. The STB sometimes refers to the pipelines subject to its jurisdiction as "non-energy" pipelines. *See* U.S. SURF. TRANSP. BD., ABOUT STB, https://prod.stb.gov/about-stb/. This article will not use that terminology because it would presuppose the analysis to be applied. Moreover, the distinction is not fully accurate because the STB has jurisdiction over coal-slurry pipelines because they compete with coal transported by rail. *See* section III.A.3, below.

gas if it was mixed with natural gas. In the 1970s, Congress reorganized the FPC into the Federal Energy Regulatory Commission (FERC) and gave FERC authority over the ICA's regulation of pipeline carrying "oil"—broadly defined as energy petrochemicals.[68] In 1995, Congress replaced the ICC with the Surface Transportation Board (STB) and the ICA was recodified (except as it applies to FERC's oil pipelines) as the Interstate Commerce Commission Termination Act (ICCTA), without any substantive change in jurisdictional scope.[69] At no point in any of this history was the scope of pipeline regulation narrowed regarding commodities transported.

1. The Hepburn Act of 1906

The history of federal pipeline regulation begins with Ida M. Tarbell. The quintessential "muckraker," Tarbell was a legendary journalist whose legacy is not limited to pipelines.[70] But for our purposes, she is credited with being the journalist who exposed the business practices of the Standard Oil monopoly.[71] From 1902 to 1904 she authored a series of investigative exposés, that were eventually republished together as *The History of the Standard Oil Company*.[72] The hugely influential work meticulously documented the market abuses of John D. Rockefeller and Standard Oil. Tarbell ended it with the following call to action:

> And what are we going to do about it? for it is our business. We, the people of the United States, and nobody else, must cure whatever is wrong in the industrial situation, typified by this narrative of the growth of the Standard Oil Company. *That our first task is to secure free and equal transportation privileges by rail, pipe and waterway is evident. It is not an easy matter. It is one which may require operations which will* seem severe; but the whole system of discrimination has been nothing but violence, and those who have profited by it cannot complain if the curing of the evils they have wrought bring hardship in turn on them. *At all events, until the transportation matter is settled, and settled right, the monopolistic trust will be with us, a leech on our pockets, a barrier to our free efforts.*[73]

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68. *See* discussion in sections III.A.2, III.A.3, and III.A.3(a).

69. *See* discussion in section III.A.4.

70. *See, e.g.*, Leigh v. Salazar, 677 F.3d 892, 897 (9th Cir. 2012) ("Open government has been a hallmark of our democracy since our nation's founding. As James Madison wrote in 1822, 'a popular Government, without popular information, or the means of acquiring it, is but a Prologue to a Farce or a Tragedy; or, perhaps both.' Indeed, this transparency has made possible the vital work of Ida Tarbell, . . . and the countless other investigative journalists who have strengthened our government by exposing its flaws.") (internal citations omitted).

71. When Tarbell was growing up in Pennsylvania, John D. Rockefeller ran her father out of business by using the sort of business practices that she later uncovered and exposed, making her consequential journalism one of history's more wholesome stories of revenge.

72. IDA M. TARBELL, THE HISTORY OF THE STANDARD OIL COMPANY (1904); *see also* Jeff D. Makholm & Laura T. W. Olive, *The Politics of U.S. Oil Pipelines: The First Born Struggles to Learn from the Clever Younger Sibling*, 37 ENERGY L.J. 409, 412 n.10 (2016).

73. *See* TARBELL, *supra* note 72, VOL. II at 292 (emphasis added). *See also Williams Pipe Line Co.,* 21 FERC ¶ 61,260, at p. 61,594 n.176 (1982), *rev'd sub nom.* Farmers Union Cent. Exch., Inc. v. FERC, 734 F.2d 1486, 1506 (D.C. Cir. 1984) (relying on the work of Ida Tarbell in interpreting the purpose of the Hepburn Act). This conclusion was in line with some contemporary academic commenters who proposed com-mon carrier law as a way to curb monopoly abuse. *See* Bruce Wyman, *The Law of the Public Callings as a Solution of the Trust Problem*, 17 HARV. L. REV. 156, 166 (1904) ("Wherever virtual monopoly is found the situation de-

Tarbell's call was heard and taken seriously by many, including President Theodore Roosevelt and the progressives in Congress. In February 1905, the House unanimously requested an investigation into the "unusually large margins between the price of crude oil or petroleum and the selling price of refined oil and its by-products" and whether legislation or legal action was warranted.[74] In May 1906, the Commissioner of Corporations prepared a nearly 500-page report to Congress that echoed Tarbell's conclusions.[75] In transmitting the report to Congress, President Roosevelt identified the report as "of capital importance" in evaluating the Hepburn Act.[76] Tarbell's journalism, which turned public opinion against Standard Oil, is properly credited with the regulation of interstate oil pipelines along the lines she proposed.[77] Ultimately, the following language was included in the Hepburn Amendment to the Interstate Commerce Act (ICA) (hereinafter "Hepburn Act"),[78] passed in June of 1906:

> SEC. 1. That the provisions of [the Interstate Commerce Act] shall apply to any corporation or any person or persons engaged in the transportation of oil or other commodity, except water and except natural or artificial gas, by means of pipe lines . . .[79]

The effect of this language was to make oil pipelines common carriers regulated by the Interstate Commerce Commission (ICC). The defining feature of a common carrier is an obligation to carry another's product upon reasonable request, at a reasonable rate, and without discrimination. The Hepburn Act thus closely followed the spirit of Tarbell's proposal.

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mands this law that all who apply shall be served, with adequate facilities, for reasonable compensation and without discrimination; otherwise in crucial instances of oppression, inconvenience, extortion and injustice there will be no legal remedies for these industrial wrongs.").

74. H.R. 499, 58th Cong. (1905); 39 CONG. REC. 2666 (Feb. 15, 1905).

75. DEP'T OF COM. & LAB., REPORT OF THE COMMISSIONER OF CORPORATIONS ON THE TRANSPORTATION OF PETROLEUM, H.R. Doc. No. 59-812, at 37 (1st Sess. 1906) ("The Standard Oil company has all but a monopoly of the pipe lines in the United States. Its control of them is one of the chief sources of its power. . . . The Federal Government has not yet exercised any control over the pipe lines engaged in interstate commerce. The result is that the charges made by the Standard for transporting oil through its pipe lines for outside concerns are altogether excessive, and in practice largely prohibitive.").

76. MESSAGE FROM THE PRESIDENT OF THE UNITED STATES TRANSMITTING A REPORT BY THE COMMISSIONER OF THE BUREAU OF CORPORATIONS IN THE DEPARTMENT OF COMMERCE AND LABOR ON THE SUBJECT OF TRANSPORTATION AND FREIGHT RATES IN CONNECTION WITH THE OIL INDUSTRY, S. DOC. NO. 59-428 (1st Sess. 1906).

77. George Bittlingmayer, *The Stock Market and Early Antitrust Enforcement*, 36 J.L. & ECON. 1, 7-8 (1993); Makholm & Olive, *supra* note 72, at 409, 412. *But see* Alexandra B. Klass & Danielle Meinhardt, *Transporting Oil and Gas: U.S. Infrastructure Challenges*, 100 IOWA L. REV. 947, 960 (2015) (attributing the Act's genesis to Kansas refineries complaining to Congress).

78. Pub. L. No. 59-337, 34 Stat. 584 (1906) [hereinafter Hepburn Act]. President Roosevelt directly campaigned for the passage of the Hepburn Act—which was a large bill with much broader implications—in one of the earliest examples of his use of the "bully pulpit." *See* LIBR. OF CONG., Theodore Roosevelt, Theodore Roosevelt Papers: Series 5: Speeches and Executive Orders, -1918; Subseries 5B: "White House Volumes," 1901 to 1909; Vol. 11, 1905, Mar. 4-June 22. Retrieved from the Library of Congress, www.loc.gov/item/mss382990708.

79. Hepburn Act, 34 Stat. at 584 (codified as amended at 49 U.S.C. app. § 1(1)(b) (1988)). Note that this provision was modified slightly by the Transportation Act of 1920, Pub. L. No. 66-152, 41 Stat. 474. However, this language change has been held to not effect a substantive change. Valvoline Oil Co. v. United States, 308 U.S. 141, 145 (1939); *Interstate Energy Co.*, 32 FERC ¶ 61,294, at p. 61,692 n.4 (1985).

The driving motivation behind this statute was clearly to regulate the transportation of *oil*.[80] It is therefore remarkable that the statute explicitly covers all other commodities not specifically exempted. The statute could have been drafted to simply apply to the "transportation of oil by means of pipe lines." The debates in Congress indicate a clear understanding that the scope was comprehensive unless exemption were made.[81] The record also reveals little knowledge as to what else would be covered.[82] The Senate considered and rejected an amendment that would have reigned in the Hepburn Act's "comprehensive" scope.[83] In the end, the Hepburn Act singled out four categories of commodities: (1) oil; (2) other commodities; (3) water; and (4) natural or artificial gas. These distinctions within the Hepburn Act presage the current pipeline regulatory framework. Pipelines carrying each of these commodities would eventually be given their own regulatory regime (or in the case of water pipelines, remained unregulated).[84]

Equally notable is the Hepburn Act's exclusion of "natural or artificial gas." This exemption has a straightforward and timeless explanation: a friendly legislator was looking out for the interests of the burgeoning gas pipeline industry. That legislator was Senator Joseph P. Foraker of Ohio.[85] Senator Foraker did not want the ICA's obligations to be imposed on Cincinnati's gas utility, whose pipelines partially crossed state lines.[86] Various amendments would have more narrowly tailored the proposed exemptions to Senator Foraker's concerns by only transportation for "municipal purposes."[87] However, these were rejected.[88]

80. CONFERENCE REPORT TO ACCOMPANY H.R. 12987, S. DOC. NO. 59-476, at 1 (1st Sess. 1906) (Conf. Rep.) (house bill sent over to the Senate initially only covered "the transportation of oil by pipeline"). *See also* 40 CONG. REC. 6368 (May 4, 1906) (statement of Sen. Lodge) ("All I want to get at is the transportation of oil, for that is where the great abuse is."). Further, neither the HISTORY OF THE STANDARD OIL COMPANY nor the Commissioner of Corporations report have any discussion of natural gas or other piped commodities. Indeed, it is quite clear that the original target of the legislation was not only one commodity, but in fact one company: Standard Oil. 40 CONG. REC. 7000 (May 17, 1906) (statement of Sen. Lodge) ("My object, I state frankly, in this amendment is to bring the pipe lines of the Standard Oil Company within the jurisdiction of the Interstate Commerce Commission . . . I care little about the natural-gas feature of this amendment.") (partially quoted in *Williams Pipe Line Co.,* 21 FERC ¶ 61,260, at p. 61,596 n.196 (1982)).

81. 40 CONG. REC. 6369 (May 4, 1906) (Sen. Foraker) ("If I understand, the Senator from Montana has offered an amendment striking out the words 'or other commodity.' If that should be adopted, of course my amendment inserting the words 'except natural gas' would not be necessary. Therefore I am willing to withdraw my amendment for the present, if I may do so.").

82. 40 CONG. REC. at 6368 (May 4, 1906) (Sen. Carter) ("I should think that it would be better to have it apply to oil alone. I do not know, nor does anyone know, what the term 'other commodity' in that connection would include beyond gas and water.").

83. S. JOURNAL, 59th Cong., 1st Sess. 465-66 (1905-1906) (senate rejecting an amendment to strike the words "or other commodity" by a vote of 53 to 22). *See also* 40 CONG. REC. 6369-70 (senate debate of the amendment).

84. That is, unregulated in terms of economic practices. *See* note 4, *supra*.

85. Makholm & Olive, *supra* note 72, at 409, 415.

86. 40 CONG. REC. 6361-71 (May 4, 1906).

87. 40 CONG. REC. 7006 (May 17, 1906) (statements of Sens. Taliafero and Beverage). *See also* 40 CONG. REC. at 6999-7005.

88. S. JOURNAL, 59th Cong., 1st Sess. 505 (1905-1906).

The Senate eventually adopted an exemption in line with Senator Foraker's proposal exempting all natural and artificial gas transportation by pipeline.[89]

We therefore have a sense of the *purpose* of exempting natural and artificial gas from the Hepburn Act's scope: to protect the burgeoning gas utilities. But the Act did not provide a *definition* for either natural or artificial gas. We do have contemporary government and legislative documents that confirm that natural gas had the same meaning it does today: a fuel gas associated with oil reserves primarily composed of methane—which was then often called "marsh gas" because of its association with anaerobic plant decay.[90] And artificial gas was understood to be a substitute in competition with natural gas.[91]

Interestingly, the motivation to exempt water pipelines from the Hepburn Act does not appear to have been to protect local utilities from federal regulation.[92] Rather, the legislative debate reveals that the purpose of exempting water pipelines was to not regulate large Western irrigation projects.[93] The credit for

89. 40 CONG. REC. 6373 (May 4, 1906). Another commenter refers to this moment as "the day in history when U.S. oil and gas pipelines embarked on separate evolutionary paths." *See* Makholm & Olive, *supra* note 72, at 415.

90. U.S. GEOL. SURV., BULL. 300: ECONOMIC GEOLOGY OF AMITY QUADRANGLE, PA., H.R. DOC. NO. 59-53, at 66 (2d Sess. 1906) ("The chief constituent is methane (CH4), the lowest member of the paraffin series of hydrocarbons. Methane is one of the products of the destructive distillation of coal and consequently constitutes a large proportion of ordinary coal gas. It is also produced in association with hydrogen when plants decay at the bottom of rivers and swamps. The name 'marsh gas' is therefore sometimes applied to it . . . Occasionally a well yields this gas in a nearly pure condition. Generally, however, there is quite a proportion of impurities."); U.S. GEOL. SURV., BULL. 296: ECONOMIC GEOLOGY OF INDEPENDENCE QUADRANGLE, KANS., H.R. DOC. NO. 59-935, at 45 (1st Sess. 1906) ("Natural gas is principally composed of marsh gas, CH4."); *see also* U.S. GEOL. SURV., MINERAL RESOURCES OF THE UNITED STATES, H.R. DOC. NO. 59-21, at 807 (2d Sess. 1905) (table showing the "Composition of Natural and Manufactured Gas" with "Marsh gas, CH4" listed first).

91. U.S. GEOL. SURV., MINERAL RESOURCES OF THE UNITED STATES, H.R DOC. NO. 59-21, at 770 (2d Sess. 1905) ("It will be observed that prices for artificial gas are usually low in the States where it comes into competition with natural gas"). U.S. GEOL. SURV., MINERAL RESOURCES OF THE UNITED STATES, H.R. DOC. NO. 59-21, at 770 (2d Sess. 1905) ("It will be observed that prices for artificial gas are usually low in the States where it comes into competition with natural gas").

92. Although, there was some debate as to the meaning of the exemption when only transporting "for municipal purposes" was briefly considered. *See* 40 CONG. REC. 6371 (May 4, 1906) (Sen. Aldridge asking Sen. Lodge if such an exemption would "include water for drinking purposes . . . [and] bathing purposes.").

93. 40 CONG. REC. 6367 (May 4, 1906) (Sen. Carter and Sen. Lodge) ("The Senator very wisely seeks to remedy an evil from which the people of New England suffer and from which the people in all other sections of the country suffer, but will he, pray, tell us why, after dealing with the subject-matter which he seeks to remedy, does he use the broad and comprehensive term 'or other commodity' . . . I am not prepared to say that that will not Inject the Interstate Commerce Commission as a ruling factor in the management of the two large irrigation schemes partly in the State of Montana. One of them passes out of the jurisdiction of the United States into Canada, and the other crosses the line of the State of North Dakota from our State. Is the Senator from Massachusetts prepared to say, without further consideration, that this water, not for municipal purposes, because the Senator has guarded that— Mr. LODGE. Will the Senator allow me to interrupt him? Mr. CARTER. Yes. Mr. LODGE. If the Senator from Montana is disturbed about the Interstate Commerce Commission carrying water by pipe lines, I will say that I am perfectly willing to except water."); *see also* 40 CONG. REC. 6372 (May 4, 1906) (Sen. Carter) ("In reply to the inquiry of the Senator from Virginia, so far as it applies to the transportation of water, I desire to say that my special solicitude in that behalf is to leave our irrigation canals subject to the local jurisprudence which is especially applicable thereto. For instance, one large system or canals conducting water from Idaho into Utah utilizes pipe lines to the extent of several miles. Therefore, it would be unquestionably true, if this exception were not made, that the pipe lines and the canals thus constructed would be subject to the regulations of the Interstate Commerce Commission. The same would be true with ref-

this exemption appears to belong to Senator Carter of Montana.[94] While there does not appear to be any precedent interpreting this exemption, the sort of projects Congress had in mind in 1906 bear a striking similarity to the interstate water pipelines envisioned today as a possible response to climate change.

Ultimately, it was the Sherman Act, not the Hepburn Act, which defeated Standard Oil. In 1911, the Supreme Court upheld an order under that act to break up the company.[95] Until that time, the Hepburn Act had not been a meaningful check on Standard's monopoly because the company had adopted some transparent maneuvers to attempt to avoid jurisdiction.[96] In fact, it wasn't until June 1911—perhaps emboldened by the Supreme Court's *Standard Oil* decision the previous month—that the ICC instituted an investigation: *In the Matter of Pipe Lines*.[97] Ultimately, the ICC determined the pipelines were common carriers and ordered them to file tariffs containing their rates for transportation at the Commission.[98] The now defunct Commerce Court found this to work an unconstitutional "taking" of property without just compensation.[99] However, the Supreme Court reversed this decision in a short decision authored by Oliver Wendell Holmes.[100] Since that time, oil pipelines have been regulated as common carriers under the ICA.

2. The Natural Gas Act of 1938

Before the eventual passage of the Natural Gas Act, Congress repeatedly considered whether and how gas pipelines should be regulated. As described above, Congress declined to regulate natural gas pipelines as common carriers under the Hepburn Act in 1906. Less than a decade after passage of Hepburn Act, Congress considered the issue again. Senate Bill 3445 sought to make gas pipelines common carriers by adding "natural gas" to the list of commodities covered by the Hepburn Act provision discussed above.[101] The discussions in

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erence to a general scheme of irrigation involving flumes, pipes, canals extending across the line of North Dakota from the State of Montana."); *see also* 40 CONG. REC. 7002-03, 7006-07 (May 17, 1906).

94. *Id.*

95. Standard Oil Co. v. United States, 221 U.S. 1 (1911). Of note, Standard Oil's gas pipelines were not subject to this enforcement so all of Standard's gas infrastructure remained with Standard Oil (New Jersey); Klass & Meinhardt, *supra* note 77, at 947, 992 n.300.

96. *See* Klass & Meinhardt, *supra* note 77, at 960-961. *See also* The Pipe Line Cases, 234 U.S. 548, 559 (1914) ("the Standard Oil Company refused, through its subordinates, to carry any oil unless the same was sold to it or to them, and through them to it, on terms more or less dictated by itself.").

97. 24 I.C.C. 1 (1912), *vacated* Prairie Oil & Gas Co. v. United States, 204 F. 798, 800 (Comm. Ct. 1913), *rev'd in relevant part sub nom. The Pipe Line Cases*, 234 U.S. 548.

98. *Id.*

99. *Prairie Oil & Gas Co.*, 204 F. at 825.

100. *The Pipe Line Cases*, 234 U.S. at 560-61 ("The situation that we have described would make it illusory to deny the title of commerce to such transportation, beginning in purchase and ending in sale, for the same reasons that make it transportation within the act. . . . The whole case is that the appellees, if they carry, must do it in a way that they do not like. There is no taking and it does not become necessary to consider how far Congress could subject them to pecuniary loss without compensation in order to accomplish the end in view."). The specific facts of this decision also created a narrow exception for truly self-contained pipeline systems called the Uncle Sam exemption, discussed further below. *Id.* at 561-62.

101. S. 3345, 63d Cong., 1st Sess., 50 CONG. REC. 5847, 5847-49 (1913).

Congress corroborate the intuitive understanding that this bill was meant to remove gas from the exempted products, leaving only water unregulated.[102] Ultimately, the proposal died in the House after another vigorous defense by gas pipeline interests.[103] Again, the argument was that gas pipelines primarily operated as local utilities, whose service would be disrupted by common carriage obligations, and that state utility regulation was adequate to protect consumers.[104]

Then the Supreme Court issued three decisions that precluded state regulation of interstate gas pipelines, creating a regulatory gap.[105] Opponents of regulation could no longer point to state regulation as an adequate protector of consumer interests. Still, Congress took a while to settle on a solution to this problem.[106] Congress directed the Federal Trade Commission (FTC) to investigate natural gas transportation in 1928.[107] This massive and far-reaching report, "Report No. 84-A," was delivered to Congress on New Year's Eve 1935.[108] Each year between 1935 and 1937 a different version of the Natural Gas Act (NGA) was considered before the final version was passed in 1938.[109] Ultimately, the NGA gave the Federal Power Commission (FPC) jurisdiction over natural

102. *See To Make Gas Pipelines Common Carriers: Hearings on Sen. Bill 3345 Before the H. Comm. On Interstate and Foreign Commerce*, 63d Cong. 21 (1914) (statements of Sen. Reed of Missouri) [hereinafter S.B. 3345 Hearings].

103. William A. Mogel & John P. Gregg, *Appropriateness of Imposing Common Carrier Status on Interstate Natural Gas Pipelines*, 25 ENERGY L.J. 21, 35-36 (2004). *See also* S.B. 3345 Hearings, *supra* note 102, at 73-156.

104. *See, e.g.*, S.B. 3345 Hearings, *supra* note 102, at 143-44 (statement of Eugene Mackey, General Counsel, Kansas Natural Gas Company); *id.* at 150 (statement of Samuel S. Wyer, Am. Inst. of Mining Eng'rs); *id.* at 9 (statement of Rep. Esch of Wisconsin) (noting that natural gas was more difficult to store than oil).

105. Missouri v. Kan. Nat. Gas Co., 265 U.S. 298 (1924); Public Utils. Comm'n of R.I. v. Attleboro Steam & Elec. Co., 273 U.S. 83 (1927); State Corp. Comm'n of Kansas v. Wichita Gas Co., 290 U.S. 561, 563 (1934); *see also* United Distrib. Cos. v. FERC, 88 F.3d 1105, 1122 (D.C. Cir. 1996) ("The NGA was intended to fill the regulatory gap left by a series of Supreme Court decisions that interpreted the dormant Commerce Clause to preclude state regulation . . . ."). *See also* Phillips Petroleum Co. v. Wisconsin, 347 U.S. 672, 682–83 (1954) ("There can be no dispute that the overriding congressional purpose was to plug the 'gap' in regulation of natural-gas companies resulting from judicial decisions prohibiting, on federal constitutional grounds, state regulation of many of the interstate commerce aspects of the natural-gas business."); Jim Rossi, *The Brave New Path of Energy Federalism*, 95 TEX. L. REV. 399 (2016) (describing the overriding purpose of the NGA was to close a regulatory gap but not discussing the Hepburn Act except as applied to railroads). This article takes the position that this gap was created first by the exemption of natural gas from Hepburn Act and then later by these dormant Commerce Clause orders from the Supreme Court.

106. *See generally* Donald J. Libert, *Legislative History of the Natural Gas* Act, 44 GEO. L. J. 695, 699 (1956); *see also* Associated Gas Distribs. v. FERC, 824 F.2d 981, 997 (D.C. Cir. 1987) ("The legislative history here consists entirely of congressional inaction.") (finding that Congress never elected to impose common carrier status on natural gas pipelines).

107. S. RES. NO. 83, 70th Cong. (1928); 69 CONG. REC. 3054 (Feb. 15, 1928). *See also* Libert, *supra* note 106, at 697-98. The House of Representatives also commissioned a report about this time which focused on oil and gasoline pipelines, but recommended regulation of interstate natural gas pipelines as well. *Id.* at 698 (discussing H.R. RES. NO. 72-59, CONG. REC. 2259, 2263 (1st Sess. 1932); REPORT ON PIPELINES, H.R. REP. NO. 72-2192 (2d Sess. 1933)).

108. FED. TRADE COMM'N, FINAL REPORT NO. 84-A, ECONOMIC, CORPORATE, OPERATING AND FINANCIAL PHASES OF THE NATURAL-GAS-PRODUCING, PIPELINE, AND UTILITY INDUSTRIES, WITH CONCLUSIONS AND RECOMMENDATIONS, S. DOC. NO. 70-92 (1st Sess. 1936) [hereinafter REPORT NO. 84-A].

109. Libert, *supra* note 106, at 696-97 (noting that the 1937 version was ultimately passed in 1938).

gas pipelines.[110] It included the following definition of "natural gas" which remains unchanged to this day,

> "Natural gas" means either natural gas unmixed, or any mixture of natural and artificial gas. [111]

This circular definition of natural gas is plainly unhelpful for our purposes. However, if the terms artificial gas and natural gas have the same meaning in the NGA as the Hepburn Act, then all commodities other than water were now regulated with the NGA's passage. In other words, any commodity must either be natural or artificial gas, and be regulated by the NGA,[112] or it must be something other than natural or artificial gas, and thus be regulated under the Hepburn Act. There is contemporary support for this understanding in the legislative record.[113] It appears that the NGA was understood to be closing the gap left by the Hepburn Act's exemption of natural and artificial gas as well as the Supreme Court decisions.[114]

Perhaps the best indication of what the term "natural gas" means comes from the comprehensive Report No. 84-A, which surveyed the entire gas industry, and which was the explicit basis for Congress' passing the NGA.[115] The report contains several definitions for natural gas that all match the common definition that has been consistent from the turn of the last century to today.[116] For

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110. 15 U.S.C § 717a(5). While in some parts modelled off the ICA and addressing a similar problem, the NGA regulated pipelines under a different, more comprehensive regulatory regime. *See* California v. Southland Royalty Co., 436 U.S. 519, 523 (1978) ("[t]he fundamental purpose of the Natural Gas Act is to assure an adequate and reliable supply of gas at reasonable prices."). A fulsome comparison of the substance of the NGA and Hepburn Act is beyond the scope of this article, but the different jurisdiction scopes are briefly discussed in section V, *infra*.

111. Natural Gas Act, Pub. L. No. 75-688, 52 Stat. 821, 822 (1938) (codified at 15 U.S.C. § 717a(5)) [hereinafter NGA].

112. Or potentially regulated, in the case of artificial gas.

113. *See Hearings Before the House Committee on Interstate and Foreign Commerce on House Bill 2008, To Regulate the Transportation and Sale of Natural Gas in Interstate Commerce and for Other Purposes*, 75th Congress 1st session (1937) [hereinafter NGA Hearings] (Statement of W.L. Dickey, Director of Law, National Association of Railroad and Utilities Commissioners) ("*Our present Federal laws exclude pipelines engaged in interstate commerce carrying gas from the jurisdiction of the Interstate Commerce Commission*. This is made specific in legislation or laws governing other utilities engaged in interstate commerce, and if they are not within the jurisdiction of State laws through which they operate, they are not subject to any regulation, either State or National. It is for these reasons that we are heartily in favor of the passage of [the NGA].") (emphasis added); *id.* at 97 (Dickey) ("And I might say here that the natural-gas companies, as far as I am able to discover, are the only utilities that were not included in national or State legislation for the purpose of regulating interstate commerce. I do not know how that happened, but, nevertheless, they were not regulated by the Interstate Commerce Commission. And we are attempting to regulate them in Ohio through the utilities commission, and that is why we are in the United States court").

114. *Id.*

115. NGA, , 52 Stat. at 822 (codified at 15 U.S.C. §717(a)) ("SECTION 1(a) As disclosed in reports of the Federal Trade Commission made pursuant to S. Res. 83 (Seventieth Congress, first session) and other reports made pursuant to the authority of Congress, it is hereby declared that the business of transporting and selling natural gas for ultimate distribution to the public is affected with the public interest, and that Federal regulation in matters relating to the transportation of natural and gas and the sale thereof in interstate and foreign commerce is necessary in the public interest").

116. REPORT NO. 84-A, *supra* note 108, *see also* ENERGY INFO. ADMIN., NATURAL GAS EXPLAINED, https://www.eia.gov/energyexplained/natural-gas/ ("Natural gas contains many different compounds. The largest

instance, in discussing the "Origin, Occurrence, and Composition of Natural Gas," Report No. 84-A notes that:

> Natural gas normally consists principally of methane (marsh gas), together with varying quantities of other hydrocarbon gases, such as ethane, propane, butane, etc., and nitrogen, as the principal constituents of the mixtures occurring in most natural gases. In addition, natural gases from certain fields contain carbon dioxide (sometimes in important quantities) and small quantities of other gases.[117]

Other legislative sources buttress this understanding. During the years when it was considering how to regulate gas pipelines, Congress was provided a "Minerals Yearbook" by the Department of Interior.[118] In each of these yearbooks from 1935 to 1938, natural gas received its own section whereas other sections covered carbon dioxide, helium, and other naturally occurring gases.[119] This further confirms the understanding that natural gas had a specific understanding other than simply a gas that occurs naturally. These reports also discussed uses of hydrogen in various applications, primarily the generation of synthetic fuels, but never in the context of being natural gas.[120] An earlier edition of the Mineral Yearbook from 1929 identified that "[a]verage natural gas is mainly methane."[121]

The more confounding, and eventually more litigated, question is what constitutes "artificial gas" as opposed to "natural gas." By the terms of the statute, artificial gas unmixed with natural is not covered by the NGA. The most logical differentiation between these two is on the basis of origin rather than composi-

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component of natural gas is methane, Natural gas also contains smaller amounts of natural gas liquids (NGL, which are also hydrocarbon gas liquids), and nonhydrocarbon gases."). *See also* CHRISTOPHER J. CASTANEDA, INVISIBLE FUEL: MANUFACTURED AND NATURAL GAS IN AMERICA, 1800-2000 3 (1999) ("Natural gas is composed primarily of methane, a hydrocarbon that has the composition of one carbon atom and four hydrogen atoms, or CH_4. As a 'fossil fuel,' natural gas flowing from the earth is rarely pure. It is often associated with petroleum and may contain other hydrocarbon gases and liquids, including ethane, propane, and butane.").

117. REPORT NO. 84-A, *supra* note 108, at app. II at 3536. *See also id.* at 15-19 (discussing the "Origin, Occurrence, and Composition of Natural Gas" and noting that "Methane and ethane are the principal constituents of ordinary commercial natural gas, but such gases may also contain, in varying proportions other chemical compositions, such as propane and butane.").

118. U.S. DEP'T OF INTERIOR, MINERALS YEARBOOK 1938, H.R. DOC. NO. 75-411, at 907-44, 973-76, 1299-1301 (2d Sess. 1938) (discussing natural gas, helium, and carbon dioxide as a "minor non-metal"). *See also* U.S. DEP'T OF INTERIOR, MINERALS YEARBOOK 1937, H.R. DOC. NO. 75-320, at 1055-90, 1119-22 (1st Sess. 1937) (discussing natural gas and helium); U.S. DEP'T OF INTERIOR, MINERALS YEARBOOK 1936, H.R. DOC. NO. 75-42, at 724-48, 771-74 (1st Sess. 1937) (discussing natural gas and helium); U.S. DEP'T OF INTERIOR, MINERALS YEARBOOK 1935, H.R. DOC. NO. 74-352, at 795-819, 843-66, 867-70 (2d Sess. 1936) [hereinafter 1935 MINERALS YEARBOOK] (discussing natural gas, "miscellaneous commercial gases," and helium).

119. *Id.*

120. 1935 MINERALS YEARBOOK, *supra* note 118, at 857-60 (1936) (surveying hydrogen under "miscellaneous commercial gases"). At the time of the Hepburn Act, as with the NGA, Congress primarily understood hydrogen as a potential aerospace resource for lighter-than-air travel. *See* U.S. DEPT. OF AG., REPORT OF THE CHIEF OF THE WEATHER BUREAU, H.R. DOC. NO. 59-814, at XIII (2d Sess. 1906) (mentioning "electrolyzer for the manufacture of the hydrogen gas employed in the kite balloon and the small rubber balloons.").

121. U.S. DEP'T OF INTERIOR, MINERALS YEARBOOK 1929, H.R. DOC. NO. 71-538, at Vol. II pp. 53-54 (3d Sess. 1932). In addition, a 1920 geological survey identified that "[i]n all cases . . . methane is the preponderating constituent, the characteristic hydrocarbon of natural gas." *See* U.S. GEOL. SURV., BULL. 695: THE DATA OF GEOCHEMISTRY, H.R. DOC. NO. 66-402, at 723 (2d Sess. 1920).

tion, as has been confirmed by the courts.[122] The legislative history reveals little of what Congress had in mind for "artificial gas" besides that it was understood to be an inferior substitute for natural gas.[123] Artificial gas was generally understood at the time to be relatively hydrogen-rich and derived mainly from coal.[124] However, "hydrogen gas" itself was understood to be an entirely distinct resource with agricultural, industrial, chemical, and even aeronautical applications, as well as the (then) theoretical potential to make liquid fuels.[125]

Congress focused on "natural" gas because naturally occurring gas needs to be transported by pipelines, whereas artificial gas can be manufactured near where it is consumed. The legislative history provides a good deal of insight into this point.[126] It appears that by the time the NGA was passed, artificial gas—once the dominant source of gas in the country[127]—was now only relied upon by utilities as a holdover measure when the supply of natural gas by pipeline became constrained or disrupted.[128] The view in Congress was that pipeline transportation of artificial gas was not required because "manufactured gas [was] not

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122. *See* Henry v. FPC, 513 F.2d 398, 400 (D.C. Cir. 1975).

123. NGA Hearings, *supra* note 113, at 103 (statement of Floyd C. Brown, Vice President and General Manager of Natural Gas Pipeline Company of America, and Texoma Natural Gas Company) ("so far as the heating value is concerned, . . . [m]anufactured, or artificial gas as it is often termed, is much lower in heating value than natural gas.").

124. 1935 MINERALS YEARBOOK, *supra* note 118, at 756; U.S. GEOL. SURV., BULL, NO. 695, DATA OF GEOCHEMISTRY, H.R. DOC. NO. 66-402, at 723 (2d Sess. 1920) ("high figures for hydrogen are unusual [for natural gas] and a suggest a resemblance to coal gas"); *see also* CRS REPORT, *supra* note 51, at 6 ("Commonly referred to as 'town gas' or 'water gas,' it typically consisted of hydrogen, methane, carbon monoxide, and small amounts of carbon dioxide and nitrogen. The hydrogen content of town gas ranged from 10% to 50%. . . . Today, Hawaii Gas is the only natural gas utility in the United States distributing manufactured (synthetic) gas with a significant hydrogen concentration.").

125. 1935 MINERALS YEARBOOK, *supra* note 118, at 857-60 (noting the potential of "changing coal into oil by treatment with hydrogen under pressure").

126. *See, e.g.*, REPORT NO. 84-A, *supra* note 108, at 4 ("While the report deals generally with natural gas, it is necessary to give some attention to the manufactured-gas industry, particularly where these two kinds of gas are used in the form of mixed gas.").

127. *See* CASTANEDA, *supra* note 116, at 35, 1-65.

128. NGA Hearings, *supra* note 113, at 104 (statement of Col. William T. Chantland, Attorney in Charge of Legal Work, Fed. Trade Comm'n Utilities Investigation) (statement of Floyd C. Brown, Vice President and General Manager of Natural Gas Pipeline Company of America, and Texoma Natural Gas Company) ("Many of the gas plants are being worked over and converted so that they can make oil-gas as a substitute for natural gas and to help take off some of the peak loads when the pipe line is unable to supply the full requirement.") (quoted in Henry v. FPC, 513 F.2d 398, 400 (D.C. Cir. 1975)). *See also* REPORT NO. 84-A, *supra* note 108, at 574 ("The situation at Denver is analogous to most of the large cities distant from gas fields which are now supplied in whole or large part with natural gas from a single pipe line. The former artificial gas-making equipment is maintained ready to produce in case of shutoff of the natural gas supply, or it is operated in part all of the time and its output mixed with natural gas, the resulting mixture having a lower British-thermal-unit content than the straight natural gas. . . . The necessity of maintaining these safe-guarding investments is a primary reason why the final selling price of natural gas in communities so situated cannot be as low as the delivered cost of the natural gas alone might justify. Such stand-by equipment, however, is apt to be far cheaper than a second adequate pipeline supply brought in over a sufficiently different route to minimize damage to both lines by the same natural destructive force. Most of the large American cities now supplied with natural gas retain the manufactured-gas plants in reserve or for partial supply. . . . only those cities supplied by duplicate pipe lines from different sources of supply and relatively close to the gas fields can take the risk of going without local production facilities.").

transported" because it could not "be profitably transported."[129] This makes intuitive sense as artificial gas could be manufactured where needed,[130] whereas efficient transportation of, cheaper and superior, natural gas requires pipelines.[131] There was a concern in Congress, though, that pipelines might try to avoid jurisdiction by mixing in a nominal amount of artificial gas.[132] Therefore, the definition of natural gas was broadened to include both natural gas and mixtures of natural and artificial gas, while pure artificial gas remained unregulated until mixed with natural gas. Natural gas regulation has changed dramatically in the decades since 1938.[133] But this original definition of natural gas has remained constant.

a. Natural Gas Policy Act of 1978

Perhaps the most dramatic change in natural gas regulation since the passage of the NGA was the Natural Gas Policy Act of 1978 (NGPA).[134] Generally speaking, the NGPA began the messy process of moving away from comprehensive regulation of the natural gas industry, including regulation of production, towards regulation focused on pipeline transportation.[135] One thing that was *not*

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129. 81 CONG. REC. 9315-16 (1937) (statement of Sen. Wheeler) (quoted in *Henry*, 513 F.2d at 401) (continuing, "[i]n other words, the gas produced in the city of Chicago cannot be profitably shipped out. The only kind of gas that can be profitably shipped in interstate commerce is natural gas.").

130. *See* REPORT NO. 84-A, *supra* note 108, at 4 ("Where manufactured gas is used it is almost always made from coal or oil at the local gas works by the distributing utility. Sometimes, however, gas may be purchased from 'byproduct' coke plants operating in the same locality, and in some cases from petroleum refineries. Normally, gas pipe lines are not required, except for local distribution."); *id.* at 360 ("There is no essential difference between a natural-gas distributing company and a manufactured-gas distributing company except that the latter usually has a plant in which to generate the manufactured gas."); *id.* at 592 ("Involved in these situations is the effect of cheap natural gas with higher heating value on the rate base and financial structure of companies distributing higher-priced manufactured gas. It is claimed that natural gas from Texas and Kansas can be produced, transported, and wholesaled at city gates in Illinois and Indiana for 30 cents or less, as against frequent domestic rates for manufactured gas (having approximately but half the heating value of natural gas) of 75 cents to $1, or even higher.").

131. *Id.* at 609-10 ("Only through pipe lines can natural-gas producers and consumers deal with each other.").

132. NGA Hearings, *supra* note 113, at 90 (Statement of John E. Benton, General Solicitor, National Association of Railroad and Utilities Commissioners) ("If the act is made applicable to natural gas only, as it now stands, utility lawyers are certain to take the position that it does not apply to a mixture of natural gas and artificial gas, and whether it applies or not, whether that proposition is frivolous or not, it can be resolved only by litigation through the courts to the United States Supreme Court. That litigation, as I said, is certain to arise if a loophole is left for the making of that contention. It can be rendered impossible by the very simple expedient of making this act apply to all wholesale interstate gas service, making the act applicable to such gas services whether it is natural gas, or artificial gas, or a mixture of both.").

133. One of the more important changes is that in 1977 Congress created the Federal Energy Regulatory Commission within the Department of Energy and transferred all the FPC's responsibilities, including the NGA, to that agency. *See* Department of Energy Organization Act § 402, Pub. L. No. 95-91, 91 Stat. 565, 583-585 (1977) (codified at 42 U.S.C. § 7172 (2022)) [hereinafter DOE Act].

134. Natural Gas Policy Act of 1978, Pub. L. No. 95-621, 92 Stat. 3350.

135. Richard J. Pierce Jr., *Reconstituting the Natural Gas Industry from Wellhead to Burnertip*, 25 ENERGY L.J. 57, 65-71 (2004); *see also* General Motors Corp. v. Tracy, 519 U.S. 278, 283 (1997) ("Congress took a first step toward increasing competition in the natural gas market by enacting the Natural Gas Policy Act of 1978, which was designed to phase out regulation of wellhead prices charged by producers of natural gas, and to promote gas transportation by interstate and intrastate pipelines for third parties.") (cleaned up).

changed by the NPGA was the definition of natural gas contained in the NGA of 1938. In fact, to ensure that fact was clear, the Joint Explanatory Statement of the NGPA Conference Committee included the following disclaimer:

> The definition of natural gas is identical to the definition of natural gas as provided in the Natural Gas Act. It is not intended to extend the provisions of the Act to facilities for the production of synthetic natural gas, or facilities for methane gas generated by the decomposition of organic waste.[136]

As will be discussed further below, this statement may have important consequences for FERC's ability to construe renewable natural gas and other forms of biomethane as "natural gas" rather than "artificial gas."

3. Department of Energy Organization Act of 1977

In 1977 Congress passed the Department of Energy Organization Act, creating FERC and transferring the FPC's regulatory responsibilities to it. In addition, as part of its stated purpose of "assuring coordinated and effective administration of Federal energy policy and programs,"[137] Congress transferred to FERC:

> such functions set forth in the Interstate Commerce Act and vested by law in the Interstate Commerce Commission or the Chairman and members thereof as relate to transportation of oil by pipeline.[138]

Previously, oil and "other commodities" had been regulated alike, so there was never any need to draw distinctions between the two. Now, this distinction would determine whether a pipeline carrying a non-gas commodity would be regulated by the newly created FERC or continue to be regulated by the ICC. Some guidance was provided in the House and the Senate Conference Reports, which each stated:

> It is the intent of the conferees that the term "transportation of oil by pipeline" shall include pipeline transportation of crude and refined petroleum and petroleum byproducts, derivatives or petrochemicals.[139]

An earlier version of the bill would have also transferred coal slurry pipelines to FERC.[140] However, this measure was opposed by numerous organizations on the grounds that "coal slurry pipelines pose competitive threat to rail-

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136. H.R. REP. NO. 95-1752, at 69 (2d Sess. 1978) (Conf. Rep.) [hereinafter NGPA Conference Report].

137. DOE Act § 306, 91 Stat. at 581 (codified as amended at 42 U.S.C. 7112). *See also id.* § 101(4)-(5), 91 Stat. at 567 (codified at 42 U.S.C. § 7111) ("responsibility for energy policy, regulation, and research, development and demonstration is fragmented in many departments and agencies and thus does not allow for the comprehensive, centralized focus necessary for effective coordination of energy supply and conservation programs; and . . . formulation and implementation of a national energy program require the integration of major Federal energy functions into a single department in the executive branch.").

138. Technically, the DOE Act transferred the responsibilities to the Secretary of Energy, which were then delegated to FERC by executive order. *See* Exec. Order No. 12009, 42 Fed. Reg. 46,267 (September 13, 1977) (President Carter executing the transfer).

139. S. REP. NO. 95-367, at 69 (1st Sess. 1977) (Conf. Rep.); H.R. REP. NO. 95-539, at 69 (1st Sess. 1977) (Conf. Rep.) [together hereinafter DOE Act Conference Reports]. *See* CF Indus., Inc. v. FERC, 925 F.2d 476, 478 (D.C. Cir. 1991) ("Congress did not intend to transfer to FERC jurisdiction over pipeline-transported oil and leave the ICC with jurisdiction over pipeline-transported gasoline, kerosene, and diesel fuel").

140. DOE Act Conference Reports, *supra* note 139, at 35.

roads," which were regulated by the ICC, and therefore "the problem of coal slurry pipelines ought to be looked at from a transportation, not from an energy, point of view."[141] The legislative history reveals two clear statutory purposes. First, Congress wanted FERC to regulate energy pipelines. And second, FERC's jurisdiction over "oil" pipelines should be interpreted broadly but limited to commodities connected to petroleum.

a. ICA Statutory Housekeeping in the 1970s

Two other statutory developments bear on the ICA. These are largely non-substantive, but important to know to avoid confusion. First, soon after it transferred the regulation of oil pipelines to FERC, Congress froze the ICA in time—but only for oil pipelines—as the version in effect on October 1, 1977.[142] This version was published as an appendix of the U.S. code until 1988.[143]

Second, Congress recodified the normal ICA soon after the statutory ossification described above.[144] By the express terms of the Act, this change was not meant to work any substantive legal change on the ICA's regulatory regime.[145] But the new organization and wording has the effect of making FERC's oil pipeline authority seem archaic in comparison. Notably, Congress changed the wording of the (more modern) ICA's pipeline jurisdiction to exclude oil (now regulated by FERC under the 1977 ICA) and it truncated the exemption for natural and artificial gas into simply "gas."[146] The ICA then was read as conferring ICC jurisdiction over transportation:

> by pipeline . . . when transporting a commodity other than water, gas, or oil.[147]

4. The Interstate Commerce Commission Termination Act of 1995

The last change to the pipeline regulatory framework occurred in 1995. That year Congress passed the Interstate Commerce Commission Termination Act (ICCTA), which dissolved the ICC and replaced it with the Surface Transportation Board (STB).[148] It also generally moved towards more light-handed regulation of the industries now subject to STB jurisdiction. Under ICCTA, just as under the previous iteration of the ICA, the STB has:

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141. *Id.* at 16.

142. Act to Revise Without Substantive Change the ICA, Pub. L. No. 95-473, 92 Stat. 1337, 1470 (1978) [hereinafter 1978 ICA Revisions]. *See also* Farmers Union Cent. Exch., Inc. v. FERC, 734 F.2d 1486, 1493 n.18 (D.C. Cir. 1984) (describing how the ossified version of the statute applied to oil pipelines).

143. 49 U.S.C. app. §§ 1-27 (1988). *See also* Frontier Pipeline Co. v. FERC, 452 F.3d 774, 776 (D.C. Cir. 2006). Consequently, the statute by which oil pipelines are governed is no longer published in the US code or even available from major legal research services. Fortunately, FERC hosts a digital (mostly word-searchable) version on its website. *See* https://www.ferc.gov/sites/default/files/2020-06/ica.pdf.

144. 1978 ICA Revisions, 92 Stat. 1337.

145. *Id.* at 1337 ("without substantive change"); *see also*, *Cortez Pipeline Co.*, 45 Fed. Reg. 85177 (I.C.C. Dec. 24, 1980).

146. *See Cortez*, 45 Fed. Reg. at 85178 (noting that this truncation was simply the elimination of "surplusage").

147. 1978 ICA Revisions § 10501, Pub. L. No. 95-473, 92 Stat. at 1359.

148. Interstate Commerce Commission Termination Act of 1995, §§ 202, 301, 1162, 303(2), 305(a)(1), Pub. L. No. 104-88, 109 Stat. 803, 940, 943-44 [hereinafter ICCTA].

jurisdiction over transportation by pipeline . . . when transporting a commodity other than water, gas, or oil.[149]

This jurisdiction over pipelines continues to be expressly comprehensive, covering all miscellaneous commodities. The legislative record confirms the use of the singular word "gas" (rather than "natural" and "artificial" gas) was *not* meant to exempt other gaseous commodities.[150] The bill's Conference Report expressed that Congress was "particularly concerned about the impact of regulations on the transportation of anhydrous ammonia," which is a gas.[151] And Congress requested the Government Accountability Office (GAO) to report back in three years on the impacts of competition on those pipelines subject to STB regulation.[152] The GAO submitted its report April 21, 1998.[153] In that report, it identified five commodities (three gases and two slurries) currently being transported by interstate pipelines subject to STB jurisdiction: anhydrous ammonia, carbon dioxide, coal slurry, hydrogen, and phosphate slurry.[154]

5. Conclusion: Three Pipeline Regulatory Regimes

That is the statutory foundation of our interstate pipeline regulatory regime. Since 1938, interstate pipelines carrying anything other than water have been regulated to some degree. Since 1977, we have had the current setup where two agencies administer three regimes, two of which are largely identical. The development of this framework over decades of shifting laws and agencies creates the potential for confusion. Especially when one regime is examined in isolation. Despite this convoluted statutory background, however, the agencies administering this paradigm have arrived at relatively consistent and clear jurisdictional delineations. And, with the current exception of hydrogen, these delineations have carried out the legislative intent described above.

B. The Significance of this Legislative History and Agency Precedent

Since the framework described above is comprehensive in scope, hydrogen and renewable fuels must fall somewhere within it. While clearly delineated against the backdrop of conventional fossil fuels, application of this framework to hydrogen and renewable fuels will require a degree of agency discretion, which has yet been subject to judicial scrutiny.[155] FERC and the STB have significant discretion to interpret the ambiguous provisions in administering these statutes. However, this deference may be precarious where FERC and the STB interpret the same statutory provision, especially if they do so differently.[156] Fur-

149. 49 U.S.C. § 15301(a).

150. *See* discussion in section III.C.3.a, *infra*.

151. H.R. REP. NO. 104-422, at 230 (1st Sess. 1995) (Conf. Rep.).

152. *Id.*

153. GAO REPORT, *supra* note 65, at 1.

154. *Id.* at app. I.

155. For instance, the proceedings discussed below where FERC asserted jurisdiction over renewable fuels under the ICA and the NGA were neither contested before the agency nor appealed to the Courts. *See* sections III.C.1.c and III.C.2c-d, *infra*.

156. CF Indus., Inc. v. FERC, 925 F.2d 476, 478-79 (D.C. Cir. 1991), and discussion *supra*.

ther, this authority is cabined by both (1) the clear intent of Congress expressed above in the legislative history, and (2) the agencies' obligation to either adhere to their own precedent or explain their departure from it.[157]

1. Agencies May Reasonably Interpret Ambiguous Statutes

FERC's and the STB's interpretations of the relevant statutes will be judged against the *Chevron* framework.[158] Under *Chevron*, courts will defer to an agency's reasonable interpretation of an ambiguous statute.[159] This deference extends to agencies interpreting the scope of their own jurisdiction.[160] The *Chevron* framework involves a two-step analysis.[161] First, the court must determine whether "Congress has directly spoken to the precise question at issue," and where "the intent of Congress is clear, that is the end of the matter."[162] Second, if "the statute is silent or ambiguous with respect to the specific issue," then the court must determine "whether the agency's answer is based on a permissible construction of the statute."[163]

While often generous, this deference has its limits. First, as the rule states, no deference is owed when Congress's intent is clear, that is, where the statute is not ambiguous.[164] Importantly, *Chevron* "step one" requires courts to "employ[] traditional tools of statutory construction" before concluding a statute is ambiguous.[165] Second, an agency is not entitled to deference when its interpretation of the statute is "unreasonable"—an analysis that can be conflated with ordinary arbitrary and capricious review.[166] At *Chevron* "step two," courts require that the agency provide a "reasonable explanation of how its interpretation serves the Act's objectives."[167]

Certain canons of construction are particularly relevant in interpreting the purpose of the NGA, the ICA, and ICCTA and in assessing whether each is am-

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157. For our purposes, some further explanation is required to clarify which agency is actually bound to what precedent regulating pipelines. *See* section III.B.2, *infra*. S*ee generally* National Cable & Telecomms. Ass'n v. Brand X Internet Servs., 545 U.S. 967 (2005).

158. *See, e.g.*, Associated Gas Distribs. v. FERC, 824 F.2d 981, 1003 (D.C. Cir. 1987) (deferring to FERC's interpretation of the NGA and NGPA); BP W. Coast Prod., L.L.C. v. FERC, 374 F.3d 1263, 1273 (D.C. Cir. 2004) (deferring to FERC's interpretation of the ICA and the Energy Policy Act of 1992); Riffin v. STB, 733 F.3d 340, 344 (D.C. Cir. 2013) (deferring to STB's interpretation of ICCTA).

159. Chevron, U.S.A., Inc. v. Nat. Res. Def. Council, Inc., 467 U.S. 837 (1984).

160. City of Arlington v. FCC, 569 U.S. 290, 296-97 (2013). *See also* Tesoro Alaska Co. v. FERC, 778 F.3d 1034, 1039 (D.C. Cir. 2015) (deferring to FERC's scope of authority under the ICA to incidentally regulate *intra*state transportation); Reiter v. Cooper, 507 U.S. 258, 258 (1993) (applying *Chevron* to the ICC's determination that statute did not grant it "initial jurisdiction with respect to the award of reparations") (cleaned up).

161. *See* City of Clarksville v. FERC, 888 F.3d 477, 482 (D.C. Cir. 2018); Pub. Serv. Auth. v. FERC, 762 F.3d 41, 54 (D.C. Cir. 2014) (per curiam).

162. *Chevron*, 467 U.S. at 842.

163. *Id.* at 843.

164. Flint Hills Res. Alaska, LLC v. FERC, 631 F.3d 543, 545 (D.C. Cir. 2011).

165. *Chevron*, 467 U.S. at 843 n.9.

166. Pharmaceutical Research & Mfrs. of Am. v. FTC, 790 F.3d 198, 204 (D.C. Cir. 2015).

167. Mako Commc'ns, LLC v. FCC, 835 F.3d 146, 151 (D.C. Cir. 2016) (cleaned up) (quoting Northpoint Tech., Ltd. v. FCC, 412 F.3d 145, 151 (D.C. Cir. 2005)).

biguous as to their scope. The first such interpretive tool is the starting assumption that Congress meant for terms to have their ordinary meaning.[168] For our purposes, the D.C. Circuit has found that "natural gas" can be understood to have its ordinary meaning,[169] but "oil" cannot.[170] Another, somewhat controversial, canon is that exemptions to statutes should be read narrowly, at least for "remedial" statutes.[171] The actual sequence of statutory development described above is important in applying this canon. Specifically, the statutory categories of "natural gas" and "artificial gas" were not created by defining the scope of the NGA, but rather the terms were created by defining an exemption from the Hepburn Act. Therefore, these terms should be construed narrowly—as has been the case—against the backdrop of the Hepburn Act's otherwise comprehensive regulation.

In addition, the "major questions" doctrine states that agencies cannot interpret a statute to work a radical regulatory change that Congress would not have foreseen,[172] including a deregulatory change.[173] Finally, and relatedly, interpreta-

168. California Indep. Sys. Operator Corp. v. FERC, 372 F.3d 395, 400 (D.C. Cir. 2004).

169. Henry v. FPC, 513 F.2d 395, 399 (D.C. Cir. 1975) (finding that §2(5) was "clear and unambiguous language" at least as far as the distinction between natural and artificial gas); *see also* National Cable & Telecomms. Ass'n v. Brand X Internet Servs., 545 U.S. 967, 982 (2005) ("A court's prior judicial construction of a statute trumps an agency construction otherwise entitled to Chevron deference only if the prior court decision holds that its construction follows from the unambiguous terms of the statute and thus leaves no room for agency discretion.").

170. CF Indus., Inc v. FERC, 925 F.2d 476, 478 (D.C. Cir. 1991) ("Congress intended a broader meaning of 'oil' . . . The legislative history, moreover, confirms that 'oil' was not to be given a dictionary meaning").

171. William N. Eskridge, Jr. & Philip P. Frickey, *Foreword: Law As Equilibrium*, 108 HARV. L. REV. 26, 105 (1994) (describing as statute-based canon the "narrow interpretation of statutory exemptions"); *see* ExxonMobil Gas Mktg. Co. v. FERC, 297 F.3d 1071, 1076 (D.C. Cir. 2002) ("The Natural Gas Act does not define either 'transportation,' which falls within the Commission's jurisdiction, or 'gathering,' which is exempt from FERC authority under the Act. The Supreme Court has, however, held that exceptions to the primary grant of jurisdiction in the section are to be strictly construed. Thus, the Supreme Court has consistently held that 'production' and 'gathering' are terms narrowly confined to the physical acts of drawing the gas from the earth and preparing it for the first stages of distribution.") (cleaned up) (quoting Interstate Natural Gas Co. v. FPC, 331 U.S. 682, 690–91 (1947) (construing 15 U.S.C. § 717(b) (2021)) and Northern Nat'l Gas Co. v. State Corp. Comm'n, 372 U.S. 84, 90, 101 (1963)); Boynton v. Virginia, 364 U.S. 454, 457-58, 460, 469 (1960) (requiring a broad reading of the ICA's jurisdiction over transportation "facilities" in order to prevent racial discrimination against interstate bus passengers). *See also* A.H. Phillips, Inc. v. Walling, 324 U.S. 490, 493 (1945) ("Any exemption from such humanitarian and remedial legislation must be narrowly construed") (cleaned up); *see also* Corbett v. Transp. Sec. Admin., 19 F.4th 478, 487 (D.C. Cir. 2021) ("If there is any ambiguity in [an] expansive grant of authority to [the agency], there is 'a presumption that Congress . . . desired the agency (rather than the courts) to possess whatever degree of discretion the ambiguity allows.'") (quoting Smiley v. Citibank (S.D.), N.A., 517 U.S. 735, 740-41 (1996)) (upholding the TSA's mask mandate).

172. Cass Sunstein, *There Are Two "Major Questions" Doctrines*, 73 ADMIN. L. REV. 475 (2021) (arguing that there are two distinct versions of this doctrine—a "soft" and "hard" version). In addition, the Supreme Court recently invalidated the Biden administration's vaccine mandate under this theory. National Fed'n of Indep. Bus. v. OSHA, 142 S. Ct. 661, 665 (2022).

173. *See* Farmers Union Cent. Exch., Inc., v. FERC, 734 F.2d 1486, 1507 (D.C. Cir. 1984) (vacating FERC's interpretation of "just and reasonable" that amounted to "virtual deregulation of oil pipeline rates oversteps the proper bounds of agency discretion"). *See also* Hunter v. FERC, 711 F.3d 155, 160 (D.C. Cir. 2013) (recognizing the "strong presumption against implied repeals.").

tions that create regulatory gaps are disfavored.[174] Of course, the "need for regulation cannot, of its own force, expand the reach of [an agency's] jurisdiction" where the "claimed jurisdiction cannot be reconciled with the words of the statute as ordinarily used and as likely to have been understood by Congress."[175] Nonetheless these principles caution against second-guessing Congress's intent to comprehensively regulate all pipelines.

a. *Chevron* Deference May Not Apply When Two Agencies Interpret the Same Statutory Provision

There is one final wrinkle to *Chevron* deference that is somewhat particular to the subject of this article. In general, "deference may not apply to an agency's interpretation of a statute if Congress has entrusted more than one agency with administering the statute."[176] Here, two agencies, FERC and the STB, administer their pipeline regulatory regimes based on the scope of the DOE Act's transfer of some pipelines to FERC. In *Hunter v. FERC*, the D.C. Circuit held that deference is never owed "where two competing governmental entities assert *conflicting* jurisdictional claims."[177] Therefore, if FERC and the STB disagree on their respective authorities over pipelines carrying hydrogen, neither interpretation will be owed deference. However, in the *CF Industries* decision, discussed more thoroughly below, FERC and the ICC both *agreed* on the delineation between their respective jurisdiction over ammonia pipelines. Still, the D.C. Circuit noted that it might not be able to defer to these interpretations because both agencies were interpreting the same provision of the DOE Act.[178] The Court avoided the issue of deference by finding that the more natural reading of "oil" did not include anhydrous ammonia because it was not used as a fuel—consistent with the reasoning of both agencies.[179] Note that this holding implicitly deferred to the two agencies' factual determination that ammonia was not used as fuel. This wrinkle will remain a point of uncertainty going forward and may require a greater degree of statutory scrutiny—or perhaps coordination—from FERC and the STB. If the two agencies agree, but their interpretation is not what a court would consider the most natural reading, the court will have to confront the nov-

174. FPC v. La. Power & Light Co., 406 U.S. 621, 631 (1972) ("Although federal jurisdiction was not to be exclusive, FPC regulation was to be broadly complementary to that reserved to the States, so that there would be no 'gaps' for private interests to subvert the public welfare."); *see also* FERC v. Elec. Power Supply Ass'n, 577 U.S. 260, 262 (2016) (rejecting interpretation of FPA that would not allow any regulation of wholesale demand response).

175. Henry v. FPC, 513 F.2d 395, 402 (D.C. Cir. 1975).

176. CTIA-Wireless Ass'n v. FCC, 466 F.3d 105, 116 (D.C. Cir. 2006) (citing Association of Am. Phys. & Surgeons, Inc. v. Clinton, 997 F.2d 898, 913 (D.C. Cir. 1993)).

177. Hunter v. FERC, 711 F.3d 155, 157 (D.C. Cir. 2013) (emphasis added) (not deferring to FERC's interpretation of the relative scope of its jurisdiction under NGA and Commodities Futures Trading Commission's jurisdiction under the Commodities Exchange Act).

178. CF Indus., Inc. v. FERC, 925 F.2d 476, 479 n.1 (D.C. Cir. 1991).

179. *Id.* at 478 ("Because of these considerations, we will analyze the case as if deference were inappropriate. We think that the two agencies have the better reading of the statute—which, of course, makes unnecessary the resolution of the deference issue."). The Court was also troubled by the amount of deference owed to agency determinations of their own jurisdiction, which has since been resolved.

el question of whether deference is owed when two agencies agree on how to interpret an ambiguous statute.

2. Agencies Must Follow Their Precedent or Explain Any Changes

Another limit on deference to agencies' statutory interpretation is the requirement that an agency must acknowledge and explain policy changes.[180] In order for an agency to change its statutory interpretation, the new interpretation must be permissible under the statute, there must be good reasons for the change, and that the agency must believe the new interpretation to be better.[181] Agencies are even allowed to interpret statutory provisions differently than an earlier court, as long as that court did not find the provision to be unambiguous.[182] Prior agency holdings need not be explicit, either: an agency's "consistent practice, whether adopted expressly in a holding or established impliedly through repetition, sets the baseline from which future departures must be explained."[183]

For purposes of this article, a quick summary of pipeline agency "genealogy" may be helpful. As noted above, every pipeline regulatory regime—the NGA, the ICA, and ICCTA—has each been administered by a different pair of administrative agencies, each for different periods of time, and each involving an agency that no longer exists. In the interest of avoiding confusion and repeated explanations, the following maps out which pipeline regulatory precedent, during which eras, is currently binding on which agencies.

In interpreting the NGA, FERC is bound by the decisions of the FPC from 1938 until 1977 and from its own decisions since then.[184] In interpreting the ICA, FERC is bound by decisions of the ICC from 1887 to 1977 and by its own decision since then.[185] In interpreting ICCTA, the STB is bound by decisions of

180. Southwest Airlines Co. v. FERC, 926 F.3d 851, 856 (D.C. Cir. 2019) (the "agency need not demonstrate that the reasons for the new policy are better than the reasons for the old one, but it must at least acknowledge its seemingly inconsistent precedents and either offer a reason to distinguish them or explain its apparent rejection of their approach") (cleaned up) (citing FCC v. Fox Television Stations, Inc., 556 U.S. 502, 515 (2009); Tennessee Gas Pipeline Co. v. FERC, 867 F.2d 688, 692 (D.C. Cir. 1989)).

181. *FCC v. Fox*, 556 U.S. at 515. In addition, sometimes greater justification is required, for instance when the "new policy rests upon factual findings that contradict those which underlay its prior policy; or when its prior policy has engendered serious reliance interests that must be taken into account." *Id.* (citing Smiley v. Citibank (S.D.), N.A., 517 U.S. 735, 742 (1996)).

182. National Cable & Telecomms. Ass'n v. Brand X Internet Servs., 545 U.S. 967, 982 (2005); United States v. Home Concrete & Supply, LLC., 566 U.S. 478, 488-89 (2012).

183. *Southwest Airlines*, 926 F.3d at 858 (citing Atchison, Topeka & Santa Fe Ry. Co. v. Wichita Bd. of Trade, 412 U.S. 800, 807 (1973) (plurality opinion)).

184. DOE Act § 705(a), 91 Stat. at 606-07 (codified at 42 U.S.C. § 7295) (savings provision). *See also* Panhandle E. Pipe Line Co. v. FERC, 881 F.2d 1101, 1123 (D.C. Cir. 1989) (remanding order to FERC to consider consistency with FPC precedent); *see also* TransCanada PipeLines Ltd. v. FERC, 24 F.3d 305, 308, 311 (D.C. Cir. 1994) (remanding order to FERC to consider line of Commission precedent going back to the FPC). *See also* Office of Consumers' Couns. v. FERC, 655 F.2d 1132 (D.C. Cir. 1980) (treating FERC and FPC precedent interchangeably).

185. DOE Act § 705(a), 91 Stat. at 606-07 (codified at 42 U.S.C. § 7295) (savings provision). *See also* Frontier Pipeline Co. v. FERC, 452 F.3d 774, 776 (D.C. Cir. 2006) ("The parties agree that decisions of the ICC applying the ICA prior to the 1977 legislation are treated as if they were FERC decisions; *i.e.*, if FERC deviates from such a decision, it must at least justify the deviation as it would a deviation from a decision of its own") (citing Greater Boston Television Corp. v. FCC, 444 F.2d 841, 852 (D.C. Cir. 1970)).

the ICC from 1887 to 1995 and by its own decisions since then.[186] FERC and the STB must therefore be mindful of the following precedent when approaching the issue of which of them should regulate pipelines carrying hydrogen or any of the other emerging renewable commodities.

C. Precedent Delineating Jurisdiction Between the Three Pipeline Regulatory Regimes

As should be clear, the pipeline statutory and regulatory framework has been developed almost entirely against the backdrop of a fossil-fuel energy economy. Still, the precedent to date provides enough guidance to place established renewable fuels within this framework. Placing a commodity (other than water) within the pipeline regulatory framework involves two lines of inquiry. First, it must be determined "whether the commodity is natural (or artificial) gas and therefore exempt from the Hepburn Act but subject to the NGA." If a product is not natural or artificial gas, it is subject to the Hepburn Act so it must then be determined whether it is "oil." That is, did Congress intend to transfer its regulation to FERC in 1977 or was its regulation left with the ICC (not STB).

Under this framework "natural gas" has a narrow interpretation as naturally occurring methane, components included with it or added to it, including manufactured methane that has been mixed with it; "oil" has a broad interpretation as petrochemicals with energy uses and their non-petrochemical competitors; and every other commodity is regulated by the STB. There are no commodities (other than water and sometimes artificial gas) whose transportation by pipe is left unregulated.

1. The Scope of the NGA: What Is "Natural Gas" and "Artificial Gas"?

The scope of the NGA's jurisdiction can be visualized as the stream of methane flowing from naturally occurring reservoirs to their points of consumption.[187] This stream may include elements other than methane, and the entire stream is still "natural gas," but once those elements are pulled out of this stream, the NGA no longer applies to them. Likewise, once artificial methane or another commodity enters this stream it becomes subject to NGA jurisdiction, but not before. This rule carries out the intent of Congress recounted above, and it has been consistently applied in numerous contexts by FERC, and the FPC before it. The result is a much narrower jurisdictional scope compared to the Hepburn Act.

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186. ICCTA § 204(a)(1-2), 109 Stat. at 941 (codified at 49 U.S.C. § 1301) (providing that all ICC orders and regulations shall continue in effect until modified or revoked by the STB).

187. *See Deep S. Oil Co. of Tex.*, 14 F.P.C. 308, 324 (initial decision), *aff'd* Opinion No. 284, *Deep S. Oil Co. of Tex.*, 14 F.P.C. 83 (1955) (order on initial decision), *aff'd sub nom.* Deep S. Oil Co. of Tex. v. FPC, 247 F.2d 882 (5th Cir. 1957) ("Throughout all those changes the 'natural gas' flows continuously and without interruption, first with, and later without, those impurities and other components, through the interconnected pipe lines, including those which actually cross state boundaries, to the burner tips of the consumers thereof.").

a. Natural Gas Must be Primarily Methane

As described above, Congress had in mind methane-based fuel gases both when it exempted gas pipelines from regulation in 1906 and when it subjected them to regulation in 1938. FPC and FERC precedent confirm that the NGA is purely focused on methane. Three manifestations of this principle prove that to be the case. First, while pure methane and methane mixed with other elements is subject to the NGA, every single non-methane element found with natural gas is no longer subject to the NGA when it is extracted or isolated.[188] Second, naturally occurring gases that do not contain methane are not subject to the NGA.[189] And finally, the NGA continues to govern methane even if it is liquefied, that is, no longer a gas.[190]

Congress never provided a definitive chemical definition of natural gas.[191] However, regulatory focus on methane can be reached, among other ways, by process of elimination. NGA jurisdiction attaches with the presence of methane; it is also lost in its absence. When gas is extracted, it usually contains other elements. This raw gas is sometimes referred to as "casinghead" gas (referring to point at which it leaves the well) or "wet" gas (because it contains natural gas "liquids").[192] The NGA still applies to this gas notwithstanding the impurities and other gases.[193] And NGA jurisdiction is retained over the transportation of the methane gas as these other elements are removed from it.[194] However, there is no NGA jurisdiction over the transportation of any of these elements besides methane.[195] In fact, the non-methane elements included in a natural gas stream

188. *Id.* at 316, 325, 332.

189. *Id.* at 324.

190. *Id.* at 310.

191. *Id.* at 322-23 ("I am unable to see any rational basis for the conclusion that Congress intended that regulation under the Natural Gas Act be confined to fuel gas consisting 'almost entirely of methane and ethane'") (exercising jurisdiction over casinghead gas with other elements).

192. *Deep South Oil*, 14 F.P.C.at 324. Note that many of the natural gas "liquids" are actually gases at normal temperatures and ambient pressures.

193. Permian Basin Area Rate Cases, 390 U.S. 747, 761, 818 (1968).

194. *Deep South Oil*, 14 F.P.C. at 324 ("The extraction process to which the gas is subjected, both before and after delivery is made to the interstate pipe line, does not create, or add to the constituents of the casinghead gas, any amount of either of those components. Those processes merely extract and remove from the casinghead gas stream, by simple changes in their physical environment, impurities such as carbon dioxide, nitrogen, helium, compounds of sulphur and oxygen, water and water vapor, drilling mud, rust, sand, dirt and in addition liquid hydrocarbons. Throughout all those changes the 'natural gas' flows continuously and without interruption, first with, and later without, those impurities and other components, through the interconnected pipe lines, including those which actually cross state boundaries, to the burner tips of the consumers thereof.").

195. *See Northern Nat. Gas Co.*, 25 F.P.C. 1205, 1206 (1961) (denying petition of Mid-America Pipeline Company for FPC to assert jurisdiction over Northern Natural's proposed pipeline to transport propane and other NGLs); *Panhandle E. Pipe Line Co*., 30 F.P.C. 1260 (1963) ("the Commission has no jurisdiction over the transportation of hydrocarbons to be extracted, as liquids from the gas stream") (no jurisdiction over helium); *Southern Nat. Gas. Co.*, 50 F.P.C. 1286, 1289 (1973) ("The first question concerns our jurisdiction over the sale and transportation of the liquid hydrocarbon feedstocks. It matters not whether we speak of the light liquid hydrocarbons here involved, or the heavy condensates that will also be used. It is our view that we have no jurisdiction over the sale or transportation of either, and that both Commission and judicial precedents so hold.") (citing *Panhandle E. Pipe Line Co*., 12 F.P.C. 686 (1953)); *Texas E. Transmission Corp*., 17 F.P.C. 843 (1957); *Northern Nat. Gas Co*., 28 F.P.C. 1155 (1962); Mid-America Pipeline Co. v. FPC, 330 F. 2d 226 (D.C.

could even be sold separately in advance of commingled transportation without implicating the NGA's jurisdiction over sales of natural gas.[196]

Ethane is the second most common element of natural gas, yet pure ethane transportation by pipeline is not regulated by the NGA, unless mixed with methane.[197] Rather, pure ethane pipelines are subject to FERC's regulation under the ICA.[198] In fact, even when some methane is inadvertently included in these extracts, FERC has clarified there is "no necessity for the Commission to attempt to trace these stray molecules, much less regulate them."[199] The focus of the NGA is clearly methane.

There does not appear to be any instance where the NGA was applied to a pipeline that did not carry methane. When FERC was once confronted with this issue, it has disclaimed jurisdiction. In 1978, the Cortez carbon dioxide pipeline

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Cir. 1964); Mobil Oil Corp. v. FPC, 483 F. 2d 1238 (D.C. Cir. 1973); *Columbia LNG Corp.*, 50 F.P.C. 1943, 1944 (1973), *aff'd sub nom.* Public Serv. Comm'n v. FPC, 543 F.2d 392 (D.C. Cir. 1976) ("The feedstocks with which we are here dealing are not 'natural gas.' These feedstocks are natural gas liquids. Although they are derived from natural gas, natural gas liquids as such are not subject to our jurisdiction.").

196. *Panhandle E. Pipe Line Co*., 12 F.P.C. at 703 ("sale of ethane and the hydrocarbon gases heavier than ethane while in the gas stream is not a sale of natural gas as defined in the act, and is therefore not subject to the jurisdiction of the commission"). Note that ethane is the second-lightest hydrocarbon and methane is the lightest so "ethane and the hydrocarbon gases heavier than ethane" would include every non-methane hydrocarbon. *See also Dorchester Gas Producing Co.*, 58 F.P.C. 2765, 2767 (1977) ("It is often said in the decided cases that extraction of liquids is a non-jurisdictional activity and [producer] relies on such language to support its position that the extent of its extractions from the gas it sells to [the pipeline] is a private contractual matter between itself and [the pipeline]. The Commission agrees that extraction of liquids is a non-jurisdictional activity. To the extent it is provided for in the contract originally dedicating gas to interstate commerce, the hydrocarbons liquefied pursuant to the contract are considered as having been reserved from the interstate sale, and as not being dedicated to interstate commerce.") (citing *Phillips Petroleum Co.*, 24 F.P.C. 537 (1960)); *Mobil Oil Corp.*, 483 F.2d at 1241 ("The contractual aspects of natural gas production have evolved with due regard to these natural and economic phenomena. The producer and the pipeline frequently agree that the producer will sell the gas from the well but reserve title to all the liquids and liquefiables transported. The gas pipeline company transports, along with the gas it purchased, various quantities of liquids and liquefiables that are still owned by the producer."); *Distrigas Corp.*, 47 F.P.C. 752, 816 (1972) ("Those cases, cited by Shell, where the sale of heavier hydrocarbon from a gas stream in a liquid form were found not to be jurisdictional, was because the sales were not an incident in the sale of natural gas and did not turn on the fact that the heavier hydrocarbons were extracted in the liquid state."); *see also Trunkline Gas Co*., 14 FERC ¶ 61,222, at p. 61,417 (1981) (noting cost allocation is required to account for "removal of these [liquid and liquefiable] non-methane constituents from the gas stream").

197. *Columbia Gas Transmission Corp.*, 17 FERC ¶ 61,020, at p. 61,036 (1981) ("Although ethane is itself nonjurisdictional, the sale or transportation of vaporized ethane which is commingled with natural gas is subject to Commission jurisdiction."). *See also Paiute Pipeline Co.*, 52 FERC ¶ 61,311, at p. 62,253 (1990) ("Propane is a hydrocarbon that is produced by separating it from a naturally occurring mixture of hydrocarbons and as such is the product of an engineering process. When commingled as part of natural gas, propane would be part of the natural gas, the transportation of which is subject to the NGA. When it is separated, it is not natural gas as that term is used under the NGA.").

198. *Williams Olefins Feedstock Pipelines, L.L.C.*, 145 FERC ¶ 61,303 (2013).

199. *South Jersey Gas Co*., 47 FERC ¶ 61,031, at p. 61,095 (1989). *See also Northern Nat. Gas Co*., 28 F.P.C. at 1192 (approving tariff that would give gas pipeline the "right to process its gas for certain specified hydrocarbons such as sulpher compounds, helium, nitrogen, natural gasoline, carbon dioxide, ethane, butane, propane, and other hydrocarbons, including methane, the basic constitutent [sic] of natural gas, but only insofar as the latter was incidental to the extraction of any other component"). There does not appear to be an equivalent threshold consideration as to whether gas is natural gas or "artificial gas unmixed."

requested FERC disclaim NGA jurisdiction over its proposed pipeline.[200] In evaluating the question, FERC noted that the legislative history does not clarify the meaning of natural gas and that it was "likely that Congress used the common meaning of 'natural gas' of a mixture of gases, including a sufficient component of hydrocarbons to give it heating value."[201] After, "considering the source of the production, the use of the production, and the actual chemical composition of the production involved, in light of the goals of the NGA," FERC concluded that carbon dioxide pipelines should not be subject to NGA regulation because doing so "would advance no goal or purpose of the NGA."[202]

If there was any doubt that methane is the key concern of the NGA, NGA jurisdiction is not lost when the methane is liquified, *i.e.*, is no longer a "gas" in the literal sense.[203] Further, there is no NGA jurisdiction over the non-methane components of a gas stream once extracted, even if the sole purpose of removing those non-methane elements is to use them to manufacture methane that will be returned to the same jurisdictional gas stream.[204] More recently, FERC's policy on gas interchangeability notes that natural gas is "principally methane."[205] All of this shows that FERC and the FPC's "settled course of behavior embodies that agency's informed judgment that"[206] natural gas means naturally occurring methane, with or without other elements.

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200. *Cortez Pipeline Co.*, 7 FERC ¶ 61,024 (1979). Of note, Cortez did not ask FERC to disclaim jurisdiction under its ICA authority.

201. *Id.* at 61,041. *See also id.* at 61,042 ("From the statute itself, it appears that Congress was enacting legislation to regulate a burgeoning industry and was concerned with a salable commodity and its effect on the public.") (citing FPC v. La. Power & Light Co., 406 U.S. 621, 638 (1972)).

202. *Cortez*, 7 FERC ¶ 61,024 at 61,042. *See also Paiute Pipeline Co.*, 52 FERC ¶ 61,311, at 62,253 ("not every gas that occurs naturally is subject to the NGA. A review of the legislative history of the NGA leads to the conclusion that natural gas within the meaning of the NGA has to be a hydrocarbon or mixture of hydrocarbons, but not every hydrocarbon, which can exist as a gas when it occurs alone, is necessarily natural gas within the meaning of the NGA."); *Gulf Cent. Pipeline Co.*, 50 FERC ¶ 61,381, at p. 62,166 (1990) ("In *Cortez Pipeline Co.*, this Commission issued a declaratory order stating that a proposed CO_2 pipeline was not subject to the Commission's jurisdiction under the NGA . . . the Commission concluded that Congress was referring to gas with sufficient hydrocarbons to have heating value since heating was the matter of statutory concern. The Commission therefore resolved this jurisdictional issue by applying the purpose of the NGA."). While FERC's phrasing by itself could imply that a gas with heating content could be categorized as natural gas even without methane, that has never occurred.

203. *Dynegy LNG Prod. Terminal, L.P.*, 97 FERC ¶ 61,231, at p. 62,055 (2001) (finding that FERC "retains its long-held authority to review LNG import facilities under section 3 of the NGA") (citing *Distrigas Corp.*, 47 F.P.C. 752 (1972)); *Distrigas*, 47 F.P.C. 752 (noting the dictionary definition of natural gas and LNG); *see also Kansas-Nebraska Nat. Gas Co., Inc.*, 22 FERC ¶ 61,176, at p. 61,307 & n.7 (1983) (citing *Distrigas*, 47 F.P.C. at 759) (natural gas "remains [jurisdictional] through ultimate consumption despite changes in pressure or storage."); *but see Air Prods. & Chems., Inc.*, 58 FERC ¶ 61,199, at p. 61,619 (1992) (disclaiming jurisdiction over facility to liquify natural gas for purposes of fueling trains).

204. *Columbia LNG Corp.*, 50 F.P.C. 1252, 1944, *aff'd* 50 F.P.C. 1943 (1973), *aff'd sub nom.* Public Serv. Comm'n v. FP*C*, 543 F.2d 392 (D.C. Cir. 1976).

205. *Natural Gas Interchangeability*, 115 FERC ¶ 61,325 at P 4 & n.2 (2006). *Id.* at P 5 (noting that producers evaluate whether to extract the non-methane elements depends on the relative price of "natural gas over other hydrocarbons").

206. Southwest Airlines Co. v. FERC, 926 F.3d 851, 858 (D.C. Cir. 2019) (cleaned up) (citing Atchison, Topeka & Santa Fe Ry. Co. v. Wichita Bd. of Trade, 412 U.S. 800, 807 (1973) (plurality opinion)).

b. Natural Gas Must Not Be Manufactured

The other requirement of NGA jurisdiction is that the gas must be either "natural" gas "unmixed" or a "mixture of natural and artificial gas."[207] This has been the more thoroughly vetted issue, with several bright line determinations. Of note, courts have found Congress used "clear and unambiguous language" in this statutory provision.[208] Therefore, FERC has less discretion in interpreting this provision than perhaps others.[209] Interestingly, FERC has some conflicting precedent regarding how this limitation applies to renewable sources of methane.

The starting point for this analysis is that the terms "natural" and "artificial" are comprehensive and mutually exclusive.[210] The FPC has found that Congress "viewed gas as being of two kinds—natural gas and artificial gas [and] contemplated within the meaning of 'natural gas' all gas which was not artificial."[211] The FPC also reasoned that the meanings of "natural" and "artificial" were "mutually exclusive" and that "that which is artificial can never be natural, no matter how perfect the imitation of nature."[212] Therefore, "whether or not the gas is 'manufactured' is the jurisdictional test."[213] Since the NGA covers artificial gas when mixed with natural gas, all that is needed to establish NGA jurisdiction over a pipeline is for *some* gas transported by it to be "natural."[214]

Historically, the FPC and courts looked to whether there was a molecular level change to the gas to determine if it was manufactured. For instance, the removal of non-methane molecules from a gas stream is not the "manufacture" of a cleaner natural gas.[215] Rather, creating methane molecules from other mate-

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207. 15 U.S.C. § 717a(5).

208. Henry v. FPC, 513 F.2d, 513 F.2d 395, 399 (D.C. Cir. 1975).

209. *See, e.g.*, National Cable & Telecomms. Ass'n v. Brand X Internet Servs., 545 U.S. U.S. 967, 982 (2005) (noting that a court's prior holding that a statutory term is unambiguous is binding on an agency). *See also, e.g.*, Office of Consumers' Couns. v. FERC, 655 F.2d 1132, 1146 (D.C. Cir. 1980) (FERC cannot exercise corollary authority over synthetic gas production). Interestingly, the synthetic gas plant that was the subject of the *Office of Consumers' Counsel* appeal will soon be converted to a hydrogen production facility. James MacPherson, *North Dakota gas plant to be redeveloped for clean energy*, ASSOCIATED PRESS (Aug. 16, 2021), https://apnews.com/article/business-environment-and-nature-north-dakota-407b773f6891b0bf8cfc945f8e41c755.

210. This is also consistent with Congress's decision to change the Hepburn Act's exempting language from "except natural or artificial gas" to simply "other than . . . gas" without changing the substance.

211. *Deep S. Oil Co. of Tex.*, 14 F.P.C. 308, 323 (1955) (cited positively by *Distrigas Corp.*, 47 F.P.C. 752, 816-17 (1972)).

212. *Algonquin SNG, Inc.*, 48 F.P.C. 1216, 1231-32 (1972) (rejecting jurisdiction over synthetic natural "principally methane" and "'physical indistinguishable' from gas formed in the earth.").

213. Public Serv. Comm'n v. FPC, 543 F.2d 392, 394 (D.C. Cir. 1976) (citing *Algonquin SNG*, 48 F.P.C. 1216; *Henry*, 513 F.2d 395).

214. *See, e.g.*, Office of Consumers' Counsel, 655 F.2d at 1146 ("No one in this litigation has questioned FERC's authority to assert full regulatory authority including the power of rate and tariff setting over the transportation and sale of Great Plains synthetic gas subsequent to its creation and commingling with natural gas"); *Transwestern Pipeline Co.*, 53 F.P.C. 1287 (1975) (no such thing as artificial gas mixed with natural gas: once the two are mixed, it is all natural gas).

215. Deep S. Oil Co. of Tex. v. FPC, 247 F.2d 882, 888 (5th Cir. 1957); *Deep S. Oil Co. of Tex.*, 14 F.P.C. 83 (1955) (citing Eureka Pipe Line Co. v. Hallanan, 257 U.S. 265 (1921); Michigan-Wisconsin Pipe Line Co. v. Calvert, 347 U.S. 157 (1954)).

rials is. The FPC addressed this issue in *Algonquin SNG*.[216] The FPC found that methane created from naphtha[217] was not natural gas because "naphtha does not contain methane, the principal component of natural gas" and "the process of transforming naphtha into methane involves what is essentially a manufacturing process wherein the molecular structure of the components of the feedstock are rearranged and transformed."[218] The D.C. Circuit later upheld a similar finding stating that "[i]n any event methane, the principal component of 'natural gas' is not present until the feedstock liquids have undergone a complex chemical transformation. The product resulting from this molecular rearrangement is manufactured gas."[219] Later, in *El Paso Natural Gas*, the FPC found that methane created by coal methanization was manufactured gas even though the coal contained "contains trace amounts of methane."[220] The reasoning of these cases reinforces the NGA's singular focus on methane, and also articulates a potentially consequential rule.

c. NGA Jurisdiction Over Pipelines Carrying Biomethane Turns on Whether Biomethane Can Be Considered "Natural"

The precedent described above sets up an interesting question as to whether renewable methane can ever be "natural" gas. FERC has conflicting precedent on this point. In *Natural Gas Pipeline Co.*, the FPC was faced with the issue of how to categorize methane that is produced through controlled digestion of animal waste.[221] The FPC concluded that such biomethane was "beyond the contemplation of what Congress intended to regulate" because it was "artificially created by the agency of man."[222] The agency reasoned that the waste itself was not gas and reasoned that

> even if the feedstocks contain elements of methane, the end product gas results primarily from a process which basically transforms the molecular structure of the feedstock, and in so doing creates a product of radically different form, physical description, chemical makeup, appearance, and application than the material from which the gas is derived.[223]

216. *Algonquin SNG*, 48 F.P.C. 1216.

217. Naphtha is a liquid, intermediate product distilled from crude oil that is blended into finished gasoline. It should be noted that transportation of naphtha by pipeline is subject to the ICA. *See, e.g.*, *Mid-Am. Pipeline Co., LLC*, 136 FERC ¶ 61,087 (2011) (evaluating committed service proposal of pipeline carrying naphtha and other NGLs).

218. *Algonquin SNG*, 48 F.P.C. at 1221.

219. *Public Serv. Comm'n v. FPC*, 543 F.2d at 394 (citing *Algonquin SNG*, 48 F.P.C. 1216; *Henry*, 513 F.2d 395).

220. *El Paso Nat. Gas. Co.*, 50 F.P.C. 651, 658-60 (1973); *see also id.* at 660 (noting that the naturally occurring methane "plays no part in the chemical process, nor is the presence or absence of any methane in the coal a factor relevant to the gasification process nor is it the objective of the gasification process to capture it; instead, the gasification process synthesizes methane through a chemical process in virtual disregard of the natural methane remaining.").

221. *Natural Gas Pipeline Co. of Am.*, 53 F.P.C. 802 (1975).

222. *Id.* at 804.

223. *Id.*

Later, after transfer of NGA oversight to FERC and the passage of the NGPA,[224] FERC was faced with the issue of how to characterize methane that appeared spontaneously in landfills.[225] In that case "organic waste ha[d] been collected, compacted, and covered with earth at a landfill site" and after which the "decomposition methane gases [were] available for extraction."[226] FERC was heavily influenced by the NGPA Conference Committee Report which indicated Congress did not wish to expand jurisdiction over methane created from decomposition of waste.[227] FERC reasoned that the only difference between the digester gas and the landfill gas was that "in the first situation the human activity was purposely directed to the production of methane" while in the latter "the production of methane is a serendipitous by-product of human activity directed to another purpose."[228] Finding that this was not a meaningful distinction for purposes of the NGA, FERC disclaimed jurisdiction.[229]

Very recently, however, FERC quietly asserted NGA jurisdiction over pipeline transportation of landfill gas without much controversy.[230] In *Dominion Energy Transmission, Inc.*, FERC was faced with the issue of tariff changes to facilitate transportation of both "renewable natural gas" and "biogas."[231] Renewable Natural Gas (RNG) would have been defined as methane and other elements sourced from "decomposing waste at dairies, feedlots, landfills, publicly owned treatment works, sewage treatment plants, and wastewater plants."[232] "Biogas" would have been defined as RNG with non-methane elements removed sufficiently to meet gas quality standards.[233] Though the jurisdictional status of the biomethane does not seem to have been put in issue by any participant, FERC still found that "for jurisdictional purposes, both terms fall under the broader category of natural gas, which section 2(5) of the Natural Gas Act (NGA) defines as 'either natural gas unmixed, or any mixture of natural and artificial gas.'"[234] FERC did not acknowledge that it had previously addressed the issue or cite any authority besides the wording of the statute.

224. *See* section III.A.2.a, *supra*.

225. *Natural Gas Pipeline Co. of Am.*, 13 FERC ¶ 61,165 (1980).

226. *Id.* at 61,352.

227. *Id.* (discussing NGPA Conference Committee Report, *supra* note 136, at 69).

228. *Id.*

229. *Id.*

230. *See, e.g.*, *Eastern Shore Nat. Gas Co.*, 172 FERC ¶ 61,148 (2020) (letter order accepting unopposed tariff provision to facilitate lateral service for renewable natural gas (undefined)); *Southwest Gas Corp.*, 172 FERC ¶ 62,106 (2020) (approving request of Hinshaw pipeline and local distribution company to transport renewable natural gas from production facilities to interstate pipelines). *See also Dominion Energy Transmission, Inc.*, 173 FERC ¶ 61,188 at P 15 (2020) (suspension order) ("we recognize that the issues pertaining to RNG and its transportation on FERC-jurisdictional pipelines are unique, new, and worthy of further consideration by the Commission.").

231. *Dominion Energy Transmission, Inc.*, 175 FERC ¶ 61,091 (2021). FERC has also faced this issue in *Paiute Pipeline Co.*, 176 FERC ¶ 61,134 (2021), but that tariff was rejected without prejudice on procedural grounds without discussing jurisdiction.

232. *Dominion*, 175 FERC ¶ 61,091 at P 2.

233. *Id.*

234. *Id.* at P 2 n.5 (citing only 15 § U.S.C. 717a(5)).

It is unclear from this phrasing whether FERC's *Dominion* order meant to assert jurisdiction over biomethane as artificial gas that had been mixed with natural gas or as "unmixed" natural gas in its own right. The latter would contradict its prior 1980 decision, but the former meaning would not make sense in context. This holding has dubious force going forward as it addressed an uncontested issue without acknowledging apparently contradictory precedent.[235] However, it still may telegraph FERC's motivation going forward. If FERC revisits this issue, it may have a valid argument that jurisdiction over naturally occurring methane from landfills is not as unsound as the young agency seemed to believe. After all, the NGA legislative record indicates that the primary reason for exempting artificial gas was that artificial gas could be produced where consumed whereas natural gas, found underground, could not. Similarly, while waste digesters can be located where methane is needed, landfill methane must be transported, likely by pipe. The NGPA Conference Committee Report may cut against this being a permissible interpretation, even under the *Chevron* framework.[236]

Of course, the distinction between natural and artificial gas would be academic where biomethane is mixed with fossil natural gas, because the transportation would still be jurisdictional. Even so, it seems the economics might already support the transport of unmixed biomethane.[237] And at least one major gas distributor has announced plans to go carbon-neutral by replacing all its natural gas with biomethane and hydrogen.[238] So the question may not remain academic for long. In it order setting Dominion's RNG tariff for a technical conference, FERC noted that it considered these issues "worthy of further consideration."[239] If biomethane production grows as much as should be hoped, the finer points of this distinction should become clearer.

2. The Scope of the ICA: What Is "Oil"?

FERC's jurisdictional scope over "oil" pipelines is determined by section 302 the DOE Act passed in 1977.[240] In passing that law, Congress was clear the purpose was to centralize energy regulation with FERC.[241] After an uncertain

235. *See generally* Christopher A. Shrock, Note, *The Limits of Intra-Agency Precedent in Arbitrary-And-Capricious Review*, 42 ENERGY L. J. 399 (2021).

236. It should be noted though that the NGPA Conference Report only referred to expanding jurisdiction over "facilities for methane gas generated by the decomposition of organic waste," and, at that time, the FPC had only faced the issue of jurisdiction over methane made in digesters, not underground in landfills. So, FERC's reversal on this point would not necessarily contradict Congress' intent expressed in the Report. *See* NGPA Conference Committee Report, *supra* note 136, at 69; *Natural Gas Pipeline Co. of Am.*, 53 F.P.C. 802 (1975).

237. *See Southwest Gas Corp.*, 172 FERC ¶ 62,106 at P 3 (2020) ("Southwest Gas states that it has received several requests to provide transportation service for RNG *from potential production facilities* located in Arizona *to an interstate pipeline* for delivery into California") (emphasis added).

238. Ethan Howland, *Xcel first utility to adopt net zero carbon target across gas and electric operations, CEO says*, UTILITY DIVE (Nov. 1, 2021), https://www.utilitydive.com/news/xcel-natural-gas-zero-carbon-greenhouse-emissions-goal-/609211/.

239. *Dominion Energy Transmission, Inc.*, 173 FERC ¶ 61,188 at P 15 (2020).

240. CF Indus., Inc. v. FERC, 925 F.2d 476, 478 (D.C. Cir, 1991).

241. *See* discussion of legislative history above.

start, FERC has settled on a relatively clear approach to delineating its commodity-based jurisdiction under the ICA. There are still some remaining questions, but this article proposes a simple test based on a synthesis of the recent opinions applying different tests to different commodities. FERC has jurisdiction under the ICA over two categories of products: (1) petrochemicals with potential energy applications and (2) non-petrochemicals that directly compete with energy petrochemicals. Pipelines carrying petrochemicals without potential energy applications remain regulated by the STB under ICCTA.

a. The ICA Covers Petrochemicals with Potential Energy Applications, Including Natural Gas Derivatives

FERC's ICA jurisdiction over "oil" broadly applies to all non-methane petrochemicals with potential energy uses.[242] This interpretation is consistent with Congress's broad intent for FERC to regulate energy transportation and its directive that this should include pipelines carrying "*crude and refined petroleum and petroleum by-products, derivatives or petrochemicals*."[243] In contrast to the NGA framework, the ICA's scope over petrochemicals is much less selective. Many of the disputes over NGA jurisdiction discussed above would not have materialized in the context of FERC's jurisdiction over "oil." In particular, the ICA does not make any distinction between synthetic or naturally occurring commodities, and it also covers natural gas derivatives the same as "oil" derivatives. In fact, FERC has yet to implement a limiting definition of the word "petrochemical" in this context. It has only ever limited its jurisdiction over commodities when it focused on whether the commodity was used for energy purposes.

The ICA's jurisdiction over petrochemicals has always been understood to include natural gas derivatives. Even before it was split between FERC and the ICC, the ICA was known to cover the non-methane natural gas elements (such as ethane, propane, and butane).[244] These are called natural gas "liquids" (NGLs)—even though many are gases at room temperature. This is consistent with the lack of NGA jurisdiction over these products, discussed above. When FERC took over oil pipeline responsibilities from the ICC, it also took over NGL pipe-

242. *Williams Olefins Feedstock Pipelines, L.L.C.*, 145 FERC ¶ 61,303 (2013); *Texaco Petrochemical Pipeline LLC*, 107 FERC ¶ 61,151 at P 3 (2004) ("The Department of Energy Organization Act transferred regulatory authority over the pipeline transportation of oil and gas related products from the former Interstate Commerce Commission to the Department. That authority was then delegated to the Commission.") (internal citations omitted).

243. DOE Act Conference Reports, *supra* note 139, at 69.

244. *See Pipeline Demurrage & Minimum Shipment Rule on Propane*, 315 I.C.C. 443, 444 (1962) ("Propane, isobutane, and other liquefied petroleum gas, (LPG) such as normal butane and natural gasoline are extracted in processing natural gas or refining petroleum. To maintain them in a liquid condition pressure or refrigeration is required."); *id.* at 446 n.1 (describing how Mid-America Pipeline Company drew a distinction between the gas-derivatives used for fuel versus used for chemical manufacture); Mid-Am. Pipeline Co. v. FPC, 330 F.2d 226, 227 (D.C. Cir. 1964) ("Mid-America is exclusively an interstate common carrier of natural gas liquids . . . It is subject to regulation only by the Interstate Commerce Commission."). *See also Black Lake Pipe Line Co.*, 342 I.C.C. 399 (1971) (pipeline transporting a mix of crude oil and ethane added as a diluent).

lines. There never appears to have been any controversy over this, rather it was simply taken as given.[245]

The ICA does not distinguish between naturally occurring or synthetic petrochemicals. The archetypical "oil" pipeline carries crude oil, a feedstock which must be refined before it can be consumed.[246] But the ICA also covers refined petroleum products.[247] In addition, the ICA covers synthetic crude oil,[248] which is made by upgrading particularly heavy crude oils at the molecular level in order to facilitate transportation.[249] The ICA likewise covers "diluents," which are transported upstream to be mixed with heavy crude to facilitate transportation.[250] In short, unlike the NGA, the ICA covers petrochemicals that have undergone significant chemical changes, and just as importantly, the ICA covers petrochemicals that will undergo significant chemical changes before they can be used for energy purposes.

The issue becomes more complex when pushing the limit of what qualifies as a "petrochemical" for purposes of the DOE Act. This dilemma is illustrated by FERC and the ICC's dialogue over ammonia pipelines. After FERC was given authority over oil pipelines, it originally took the position that ammonia was covered by the ICA because it is derived from natural gas[251] and was therefore a petrochemical.[252] However, it was later asked to disclaim jurisdiction over ammonia pipelines because the commodity was not used for energy purposes. In trying to determine the scope of its authority over "petrochemicals,"[253] FERC employed dueling dictionary definitions and concluded that "there is sufficient ambiguity in the term 'petrochemical' that [FERC's] jurisdiction is more appro-

245. *See, e.g.*, *Powder River Corp.*, 6 FERC ¶ 62,151 (1979); *Powder River Corp*, 14 FERC ¶ 62,080, at p. 63,123 (1981); and *Dome Pipeline Corp.*, 15 FERC ¶ 62,054, at p. 63,077 (1981) through to *Targa NGL Pipeline Co. LLC*, 173 FERC ¶ 61,001 (2020) (approving committed service); and *Roaring Fork Midstream, LLC*, 173 FERC ¶ 61,276 (2020) (approving waiver of reporting requirements). *See also* Ass'n of Oil Pipe Lines v. FERC, 83 F.3d 1424, 1433 n.17 (D.C. Cir. 1996) ("Crude oil pipelines transport unrefined petroleum; product pipelines transport refined petroleum products and liquid hydrocarbons other than crude oil, such as gasoline, diesel fuel, and natural gas liquids.").

246. *See* discussion of hydrocracking and hydrotreating below in sections VI.B.2.a(i)-(ii).

247. *See Epsilon Trading, LLC v. Colonial Pipeline Co.*, 164 FERC ¶ 61,202 (2018) (setting for hearing rates for "transportation of refined petroleum products, including gasoline, jet fuel, and diesel fuel") (case remains ongoing).

248. *See, e.g.*, *Tesoro Refin. & Mktg. Co. v. Frontier Pipeline Co.*, 105 FERC ¶ 61,227 (2003), *Big W. Oil, LLC v. Express Pipeline LLC*, 100 FERC ¶ 61,171 (2002).

249. *See, e.g.*, *Northwest Pipeline Corp.*, 23 FERC ¶ 61,163, at p. 61,358 (1983) (noting that one use of natural gas is to produce hydrogen to be used for upgrading heavy crude into synthetic crude).

250. *See Enbridge Pipelines, LLC*, 144 FERC ¶ 61,044 (2013).

251. More specifically, ammonia is made by combining hydrogen (which is derived from natural gas) with nitrogen (which is not).

252. *See Gulf Cent. Pipeline Co.*, 5 FERC ¶ 62,075 (1978) (oil pipeline board instituting investigation into ammonia pipeline rate increases); *Gulf Cent. Pipeline Co.*, 8 FERC ¶ 63,015, at p. 65,181 n.2 (administrative law judge approving settlement and finding the intent of Congress to be "abundantly clear"), *aff'd* 8 FERC ¶ 61,305 (1979).

253. At this point, FERC does not seem to have put much emphasis on the word "derivatives" that was used in the Conference Report. *See Palmetto Prods. Pipe Line LLC*, 151 FERC ¶ 61,090 at P 30 (2015) ("[a]nhydrous ammonia is an agricultural fertilizer *derived from natural gas or petroleum refinery gas*.").

priately determined by examining the overall purposes of the DOE Act."[254] As discussed below, this analysis turned on whether the commodity being transported was used for energy. The ICC agreed with FERC's view,[255] and the D.C. Circuit confirmed that FERC was not required to regulate ammonia pipelines despite the agency's past practice and ammonia's petroleum derivative status.[256] FERC has yet to disclaim ICA jurisdiction over a commodity because it is not a petrochemical.[257]

b. The ICA Does Not Cover Products That Are Not Used for Energy Purposes, Even If They are Petrochemicals

The crux of FERC's ICA jurisdiction over a commodity is whether that commodity is used for energy purposes. This principle first emerged during the debate over which agency—FERC or the ICC (now STB)—should regulate pipelines carrying anhydrous ammonia. In this inquiry, unlike the definition of "petrochemical," FERC has provided some guidance and issued several limiting interpretations. What exactly qualifies as an energy purpose has not been conclusively defined. We do know, though, that it is sufficient that a commodity could be combusted on its own or blended with other fuels.

FERC regulated ammonia pipelines under the ICA from the agency's inception through the 1980s. In fact, FERC and the ICC formalized the transfer of these pipelines to FERC by both moving to substitute FERC for the ICC in a Seventh Circuit appeal regarding an ammonia pipeline order.[258] That changed in 1989, when an ammonia pipeline's shipper filed a complaint at FERC under the ICA, which FERC dismissed in spring 1990.[259] In dismissing the case, FERC differentiated anhydrous ammonia from typical "oil."[260] As discussed above, FERC found that it was ambiguous whether anhydrous ammonia was a petrochemical.[261] Therefore, FERC elected to determine its jurisdiction "by examining the overall purposes of the DOE Act and acting in a manner that facilitates the purposes of that Act."[262] To that end, FERC identified that "the purpose of

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254. *Gulf Cent. Pipeline Co.*, 50 FERC ¶ 61,381, at p. 62,165 (1990).

255. *Gulf Cent. Pipeline Co.*, 7 I.C.C.2d 52, 56 (1990) (describing FERC's conclusions that "a hypertechnical analysis of an ambiguous term is not likely to lead to rational public administration").

256. CF Indus., Inc. v. FERC, 925 F.2d 476, 477 (D.C. Cir. 1991).

257. *See Palmetto*, 151 FERC ¶ 61,090 (exercising jurisdiction over denatured fuel ethanol without acknowledging that ethanol is not a petrochemical).

258. *CF Indus., Inc. v. FERC*, 925 F.2d at 477 (discussing CF Indus., Inc. v. United States, No. 77-2150, 1978 BL 2094 (7th Cir. Aug. 29, 1978)).

259. *Gulf Cent. Pipeline Co.*, 50 FERC ¶ 61,381 (1990).

260. *Id.* at 62,164 ("Oil pipelines transporting organic, hydrocarbon based products state all volumes, including those for petrochemicals, in barrels, while the volumes of anhydrous ammonia pipelines are stated in tons. Anhydrous ammonia pipelines also operate within substantially different pressure and heat ranges and use electric compressors because, unlike oil and gas pipelines, the commodity itself cannot be used for compressor fuel. In other words, whatever ambiguity there may be about the regulatory status of anhydrous ammonia pipelines and those that are oil pipelines in the conventional sense of the term, this ambiguity is not reflected in the engineering aspects of their operations.").

261. *Id.* (noting that "[a]s a matter of common usage within the petrochemical industry, anhydrous ammonia is considered a petrochemical because it is derived from petroleum refinery gas or from natural gas.").

262. *Id.* at 62,165.

the Act was to provide more coordinated and systematic regulation of energy resources."[263] FERC noted that Congress declined to transfer coal pipelines to FERC because coal did not compete with gas or oil, and reasoned that oil was transferred to FERC because it more closely competes with natural gas.[264] FERC found that it should not regulate anhydrous ammonia pipelines because: (1) pipeline transportation of ammonia doesn't impact the energy markets; (2) ammonia does not compete with gas or oil for heating uses or pipeline facilities; and (3) ammonia has no heating value compared to fuel hydrocarbons.[265] Taking this into consideration, FERC concluded that "regulation of [ammonia's] transportation has no practical implication for energy matters."[266] The D.C. Circuit affirmed this decision in all regards.[267]

FERC's decisions since then have elaborated on the requirement that ICA commodities have energy applications and in so doing made clear that if a commodity is not used for energy, it does not matter if it is a petrochemical or not. In 2004, FERC disclaimed jurisdiction over an ethylene pipeline despite the fact that it "is unquestionably a hydrocarbon product."[268] FERC did so because the record in that proceeding demonstrated that ethylene was "not used for energy purposes."[269] Also in 2004, FERC likewise disclaimed jurisdiction over a pipeline carrying "Polymer Grade Propylene" for the same reasons.[270] And again in 2005.[271] In each of these orders, FERC noted that the commodities could not be used for energy purposes or even travel on the same pipelines for fear of contamination.[272] These subsequent holdings also strongly imply that anhydrous ammonia is a petrochemical or derivative that would be subject to ICA regulation if it had energy applications.[273] In fact, FERC later acknowledged in dicta that anhydrous ammonia was "derived from natural gas or petroleum refinery gas."[274]

Importantly, though, ICA jurisdiction only requires that a commodity have potential, not actual, energy uses. In 2013, a pipeline carrying ethane sought a waiver similar to the ethylene and propylene pipelines'.[275] The pipeline in question represented that it was configured such that the ethane would only be delivered to ethylene manufacturers.[276] Therefore, it argued that the "ethane to be

263. *Id.*

264. *Id.* at 62,165-66.

265. *Id.* at 62,166-67.

266. *Id.*

267. CF Indus., Inc. v. FERC, 925 F.2d 476, 477 (D.C. Cir. 1991).

268. *Texaco Petrochemical Pipeline L.L.C.*, 107 FERC ¶ 61,151 at P 5 (2004).

269. *Id.*

270. *Sabine Propylene Pipeline L.P.*, 109 FERC ¶ 61,025 (2004).

271. *Enterprise Lou-Tex Propylene Pipeline L.P.*, 111 FERC ¶ 61,068 (2005).

272. *Id.* at PP 10-11; *Sabine Propylene*, 109 FERC ¶ 61,025 at PP 8-9; *Texaco Petrochemical*, 107 FERC ¶ 61,151 at P 3.

273. *See Texaco Petrochemical*, 107 FERC ¶ 61,151 at P 5 ("*Gulf Central*, *supra*, *holds* that if a hydrocarbon product shipped by an oil pipeline is not used for energy purposes, the Commission lacks jurisdiction over the transportation of that product") (emphasis added). If ammonia were not a petroleum product, this would be dicta, rather than the *holding* of *Gulf Central*.

274. *Palmetto Prods. Pipe Line LLC*, 151 FERC ¶ 61,090 at P 30 (2015).

275. *Williams Olefins Feedstock Pipelines, L.L.C.*, 145 FERC ¶ 61,303 (2013).

276. *Id.* at P 5.

transported" on its pipeline would not serve any "fuel or energy purposes."[277] Despite the fact that the petition was unopposed, FERC denied it. FERC provided the following, clarified, jurisdictional test:

> whether the product being transported is a naturally-occurring hydrocarbon that is used or can be used for energy-related purposes, as opposed to having only a non-fuel, feedstock, function.[278]

FERC emphasized that it "considers both existing and potential energy uses" when answering this question.[279] FERC recounted numerous energy applications of ethane, that include burning for heat and blending with natural gas.[280] FERC also stated it will not "disclaim jurisdiction over interstate ethane transportation based on an applicant's assertion of the intended end-use" of the products transported.[281] In other words, if a product is ever covered by the ICA, FERC will assert jurisdiction over all pipelines carrying it.

FERC has yet to conclusively define what energy uses qualify for purposes of determining ICA jurisdiction. FERC clearly had combustion in mind when articulating this rule, but it's unclear if anything else could qualify. For instance, FERC asserted jurisdiction over ethane because it has "thermal heat content *and* current and future uses of ethane as a fuel."[282] Similarly, it noted that propylene is hazardous to burn, when finding it was not a fuel.[283] FERC has also referred to analyzing whether a product is "used as a fuel *or* energy source."[284] Therefore, thermal energy is a sufficient condition to finding energy purposes in evaluating ICA jurisdiction, but it is unclear if it is a necessary condition.

c. The ICA Covers Pipelines Carrying Non-Petrochemicals That Directly Compete with Energy Petrochemicals

FERC has also asserted ICA jurisdiction over non-petrochemical energy products that compete for pipeline space with energy petrochemicals. In 2015, the Palmetto Products Pipe Line (Palmetto) applied to FERC for approval of the terms for committed service on new pipeline capacity.[285] What made Palmetto unique is that one of the commodities it planned to transport was denatured fuel

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277. *Id.* at P 7.

278. *Id.* at P 15. Note that this appears to be the first time FERC has used the words "naturally-occurring" as part of this discussion—which, in the context of exercising jurisdiction over an ethane pipeline because of its potential energy uses, should be seen as dicta. As described above, FERC routinely exercises jurisdiction over manufactured hydrocarbons under the ICA. The exact mechanics of how these hydrocarbon molecules are manufactured is described below in section below in sections VI.B.2.a(i) regarding hydrocracking.

279. *Id.* at P 16.

280. *Id.* at PP 17-21. *Id.* at P 20 ("it is unquestionable that ethane has a thermal heat content and has the capability of being burned and used for fuel and energy purposes").

281. *Id.* at P 23.

282. *Id.* at P 22.

283. *Sabine Propylene Pipeline L.P.*, 109 FERC ¶ 61,025 at P 8 (2004) ("the product could be dangerous for use as a fuel, and it could have undesirable environmental effects so there are strict emission standards relating to its release"); *Enterprise Lou-Tex Propylene Pipeline L.P.*, 111 FERC ¶ 61,068 at P 10 (same).

284. *Gulf Cent. Pipeline Co.*, 50 FERC ¶ 61,381, at p. 62,166 (1990).

285. *Palmetto Prods. Pipe Line LLC*, 151 FERC ¶ 61,090 (2015).

ethanol.[286] Palmetto acknowledged in its application that "pure ethanol likely does not meet the technical or dictionary definition of the term 'oil' or 'petrochemical.'"[287] However, in its order grating the application, FERC did not address the ethanol's origins. It simply characterized the test from *Central Gulf*, as follows: "(1) whether the commodity is a fuel source in that it has heating value and is used for energy-related purposes; (2) whether the cost of transportation will have an impact on energy markets; and (3) whether the commodity will compete with oil or other refined products for capacity in the pipeline."[288]

FERC applied this test and found it had ICA jurisdiction over the transportation of ethanol. In finding ethanol was a fuel, FERC was informed by public policy. It noted that "federal law requires ethanol to be blended with transportation fuels" and that the Energy Information Administration "recognized that ethanol has its own energy content and has classified it as a fuel source."[289] FERC also found the cost of transporting ethanol would impact energy markets because ethanol made up 10 percent of gasoline sold.[290] And finally, FERC reasoned that ethanol competes for pipeline capacity with other FERC-regulated regulated commodities.[291] It should be noted that Palmetto's application was unopposed and there has yet been any adversarial determination at FERC regarding this extension of jurisdiction over biofuels, let alone judicial review.

Finally, it should be noted that the exact relationship between the different tests articulated in *Williams Olefins* and *Palmetto* has not yet been addressed by FERC. *Palmetto* was issued shortly after *Williams Olefins* and although it articulates a different test, it does not acknowledge the preceding order. This article proposes the following distinction: the *Williams Olefins* test is for petroleum derivatives (such as ethane or ethylene) and the *Palmetto* test is for non-petroleum-derivatives (such as ethanol). Some distinction is logically required: FERC's ICA jurisdiction cannot always be contingent on a commodity competing with another regulated commodity—some commodities must be jurisdictional in their own right. Against this backdrop, and the legislative history, the most logical reading is that *Williams Olefins* holds that energy petrochemicals are intrinsically subject to ICA jurisdiction, and the *Gulf Central* test as applied by *Palmetto* determines whether commodities that are not petrochemicals should still be subject to ICA jurisdiction based on their close nexus to regulated energy petrochemicals.

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286. *Id.*

287. Petition for Declaratory Order at 33, *Palmetto Prods. Pipe Line LLC*, Docket No. OR15-13-000 (Jan. 23, 2015).

288. *Palmetto*, 151 FERC ¶ 61,090 at P 30.

289. *Id.* at P 31.

290. *Id.* (also theorizing that increased demand for pipeline transportation of ethanol would drive up the cost of transporting other products). The author notes that FERC's conclusion seems misplaced because ICA-regulated pipelines are not supposed to be able to increase their prices in response to scarcity. It also ignores the fact that because ethanol should mostly displace gasoline volumes.

291. *Id.* (noting that the ethanol would be transported in "batches" in the same manner as other products on refined products).

d. ICA Jurisdiction Over Drop-In Biofuels May Depend on the Degree they Compete with Their Petroleum Counterparts

If the logic of FERC's *Palmetto* order is applied going forward, nearly all known drop-in biofuels would be subject to the ICA. Ethanol competes the least directly with fossil fuels for customers and for pipeline space. Ethanol is not a hydrocarbon and cannot be used directly in most vehicles. The degree to which it can compete with conventional gasoline is limited by the so-called "blend-wall"—the percentage of ethanol that gasoline can have and still run in a typical car.[292] Ethanol is also problematic to transport by pipeline because it tends to corrode most pipes.[293] In contrast, the defining characteristic of more advanced "drop-in" fuels such as renewable diesel, sustainable aviation fuel, and renewable gasoline is that they match the chemical specifications of their fossil counterparts.[294] These nearly indistinguishable renewable hydrocarbons can be transported through existing pipelines.[295] They compete with their fossil equivalent for pipeline space and for customers. Therefore, if ethanol is covered by the ICA, we can safely assume that most other renewable liquid fuels would be.[296] As new products emerge, FERC may draw sharper points of division. But for now, we can expect all existing, proven biofuels to be covered by the ICA.

Regulation of drop-in biofuel transportation under the ICA common carrier regime will have interesting implications as the emerging fuels begin to displace their fossil models. For one thing, the ICA obligates all pipelines, as common carriers, to provide transportation "upon reasonable request."[297] It also prohibits discrimination between shippers.[298] For instance, pipelines must justify changes made to the product specifications in their tariffs.[299] A pipeline's product specifications must be clear, and the pipeline must transport any product that meets

292. *See, e.g.*, Marc Chupka et al., *Peeking Over the Blendwall: An Analysis of the Proposed 2017 Renewable Volume Obli*gations, THE BRATTLE GRP. (July 11, 2016), https://www.brattle.com/wp-content/uploads/2017/10/7178_peeking_over_the_blendwall_-_an_analysis_of_the_proposed_2017_renewable_volume_obligations.pdf.

293. *See* U.S. DEP'T OF TRANSPORTATION, PHMSA, ETHANOL, https://primis.phmsa.dot.gov/comm/ethanol.htm.

294. U.S. DEP'T OF ENERGY, ALTERNATIVE FUELS DATA CENTER, RENEWABLE HYDROCARBON BIOFUELS, https://afdc.energy.gov/fuels/emerging_hydrocarbon.html.

295. *See Renewable Fuel Standard Program: Standards for 2014, 2015, and 2016 and Biomass-Based Diesel Volume for 2017*, 80 Fed. Reg. 77,420, 77,471-73 (2015) (describing fewer issues with distributing and consuming renewable diesel because of its similarity to petroleum based diesel as opposed to biodiesel, which is more different).

296. This was actually the case in the *Palmetto* docket, where the pipeline also carrier biodiesel and renewable diesel blends. Petition for Declaratory Order at 4, *Palmetto Prods. Pipe Line LLC*, Docket No. OR15-13-000 (Jan. 23, 2015).

297. 49 U.S.C. app. § 1(4) (1988).

298. *Id.* at § 3(1) (prohibiting discrimination against any "person, company, firm, corporation, association, locality, port, port district, gateway, transit point, region, district territory, or any particular description of traffic.").

299. *Colonial Pipeline Co.*, 160 FERC ¶ 61,051 at PP 14-15 (2017).

those specifications.[300] It is not hard to imagine the sort of disputes that may emerge under this common carrier framework regarding the transportation of renewable products.[301] For instance, shippers of drop-in renewable fuels may try to use the ICA to gain access to fossil pipeline infrastructure that pipeline operators, or incumbent shippers, may not want to give them.

3. The Scope of ICCTA: Is Any Commodity Left Unregulated?

The STB's catch-all jurisdiction over non-oil Hepburn Act pipelines is conterminous with FERC's jurisdiction over "oil" pipelines. As the ICC articulated in its ammonia ruling, discussed above, "[t]here is no question that the transportation of [non-gas commodities] is subject to regulation. Rather, the issue is whether regulation was transferred to FERC by the section 302 DOE Act. If not, it continues to reside with [the ICC]."[302] FERC has a similar understanding of the two agencies' domains.[303] The combined jurisdiction of the two agencies' is comprehensive over all commodities (other than water) not regulated by the NGA. The scope of the exemption as to "gas," however, has been the source of some unnecessary confusion, warranting a quick correction here.

a. ICCTA Gives the STB Jurisdiction Over Pipelines Carrying Commodities Not Covered by the ICA or NGA, Including Gaseous Ones

Under ICCTA's current iteration of the Hepburn Act, the STB jurisdiction has jurisdiction "over transportation by pipeline . . . when transporting a commodity other than water, gas, or oil."[304] The legislative record shows that "gas" was simply meant as a shortened wording for "natural gas and artificial gas."[305] This history, and the concurring agency precedent, also shows us that gas has a narrow meaning, first as a limit on the Hepburn Act's jurisdiction and then, later, as defining the scope of the NGA's jurisdiction. Nevertheless, much confusion has been caused by a cursory, uncontested—and explicitly disclaimed—decision of the ICC: *Cortez Pipeline*.[306] In that order, the ICC curtly agreed it could not regulate carbon dioxide pipelines because the commodity is gaseous.[307] However, the STB has since disclaimed the logic of *Cortez*, so all agencies are once again aligned in their understanding that the pipeline regulatory framework comprehensively covers all commodities other than water.

300. *Colonial Pipeline Co.*, 114 FERC ¶ 61,276 at P 9 (2006) ("a common carrier pipeline holding itself out to move [reformulated gasoline] containing [methyl tertiary butyl ether] must do so upon reasonable request in a not unduly discriminatory manner.").

301. Some disputes have already arisen. *See Colonial Pipeline Co.*, 162 FERC ¶ 61,158 (2018) (order on dispute over pipeline tariff provisions regarding biodiesel blending following a technical conference on the subject).

302. *Gulf Cent. Pipeline Co.*, 7 I.C.C.2d 52, 55 (1990).

303. *Sabine Propylene Pipeline L.P.*, 109 FERC ¶ 61,025, at P 11 (2004) (concluding that polymer grade propylene is not subject to FERC jurisdiction and therefore resides with STB).

304. 49 U.S.C. § 15301(a).

305. 1978 ICA Revisions, 92 Stat. at 1470.

306. *Cortez Pipeline Co.*, 45 Fed. Reg. 85,177 (I.C.C. Dec. 24, 1980).

307. *Id.*

i. The *Cortez* Aberration

In 1980, Cortez sought a declaratory order from the ICC that its pipeline was not subject to that agency's jurisdiction because the carbon dioxide it carried was a naturally occurring "gas" for purposes of the Hepburn Act.[308] This was the same pipeline that had just received a related declaration from FERC, discussed above, that the carbon dioxide it carried was "[*not*] 'natural gas' within the meaning of Section 2(5) of the NGA."[309] The ICC characterized the issue as "whether Congress intended to exclude from our jurisdiction all gas types regardless of origin or source."[310] The ICC issued notice in the Federal Register on December 24, 1980, describing its "tentative conclusion" that it lacked jurisdiction over carbon dioxide pipelines.[311] The ICC gave several reasons for this, none of which hold up to much scrutiny.

First, despite explicitly acknowledging that the words "natural or artificial" in the Hepburn Act were understood by Congress to be "surplusage," the ICC relied heavily on the distinction between natural and artificial gas in the Natural Gas Act.[312] The ICC noted that the distinction between natural and artificial gas in the NGA was "based on its origin and not its physical characteristics of heat value or methane content."[313] While true, this does not concern the provision (or even statute) that the ICC was asked to rule on. Second, and most curiously, the ICC reasoned that, even though "[t]he opinion of a sister agency should be given weight, if possible, so that related statutes can be coordinated," that was not necessary because FERC's *Cortez* disclaimer did "not construe or interpret the terms natural and artificial gas."[314] Rather, the ICC somehow found that FERC disclaimed jurisdiction solely because it would not serve the NGA's purpose of preventing exploitation by "natural gas companies."[315] Aside from implicitly acknowledging that carbon dioxide is not natural gas, this was a clear misreading of FERC's *Cortez* order, which explicitly turned on its interpretation of that term.[316] Nevertheless, after receiving no critical comments, the ICC confirmed its tentative conclusion.[317]

Even when it was issued, the *Cortez* order was irreconcilable with present practice. Most obviously, FERC had just found that the carbon dioxide Cortez carries was not natural gas or artificial gas whereas the ICC's *Cortez* decision then found the exact same pipeline was exempt from its jurisdiction because it was carrying natural gas. But it is also worth noting, as described above, that

308. *Id.*

309. *Cortez Pipeline Co.*, 7 FERC ¶ 61,024, at p. 61,041 (1979) (emphasis added).

310. *Cortez*, 45 Fed. Reg. at 85,178.

311. *Id.*

312. *Id.*

313. *Id.* (citing Henry v. FPC, 513 F. 2d 395, 399 (D.C. Cir., 1975)).

314. *Cortez*, 45 Fed. Reg. at 85,178.

315. *Id.* at 85,177-78.

316. *Cortez Pipeline Co.*, 7 FERC ¶ 61,024, at p. 61,041 (1979) ("It seems likely that Congress used the common meaning of 'natural gas' of a mixture of gases, including a sufficient component of hydrocarbons to give it heating value.").

317. *Cortez Pipeline Co.*, 46 Fed. Reg. 18805 (I.C.C. Mar. 26, 1981).

FERC was, at this time, actively regulating pipelines carrying—gaseous—anhydrous ammonia under statutory authority identical to the ICC's authority over Cortez. In fact, the month before the ICC issued its Notice of Filing for Cortez, FERC had issued an ammonia pipeline order.[318]

ii. *Cortez* Disclaimed

The ICC's *Cortez* order continued to become marginalized after the ICC re-assumed jurisdiction over ammonia pipelines. As described above, Congress expressed a particular interest in ammonia pipelines when passing ICCTA and the GAO subsequently concluded that carbon dioxide pipelines were also covered by that statute.[319] Finally, in 2000, the STB faced this inconsistency directly. In Docket No. 41685, the STB was handling a complaint against the Koch (formerly Gulf Central) ammonia pipeline. In that case, Koch argued that the ICC's holding in *Cortez* meant that because "[anhydrous ammonia] is a gas" it was "thus beyond the [STB's] oversight."[320] The STB rejected this argument, noting that "the jurisdictional dividing line has been clarified since the *Cortez* case."[321] On appeal, the pipeline did not press the jurisdictional issue.[322] And the D.C. Circuit again noted without analysis that the STB's pipeline jurisdiction "includes anhydrous ammonia pipelines."[323] While this holding is limited to ammonia, the ICC has clearly cast aside the central rationale in *Cortez*, that is, that it lacked jurisdiction over "all gas types regardless of origin or source."[324]

The *Cortez* order has still caused confusion for apparently every analysis that addresses ICC or STB jurisdiction over carbon dioxide pipelines. Some authors simply conclude that carbon dioxide pipelines are unregulated,[325] and oth-

318. *Gulf Cent. Pipeline Co.*, 13 FERC ¶ 62,184, at p. 63,235 (1980).

319. H.R. REP. NO. 104-422, at 230 (1st Sess. 1995) (Conf. Rep.); GAO REPORT, *supra* note 65, at Appendix I. Other government publications reached this conclusion as well. CRS REPORT, *supra* note 51, at 10 ("Jurisdiction over rates for interstate hydrogen pipelines resides with the Surface Transportation Board (STB)."); Hydrogen Economy Statement, *supra* note 65, at 618 ("The statement recognizes that the Surface Transportation Board (STB), the Federal economic regulator of railroads, also regulates economic aspects of interstate hydrogen pipelines.").

320. *CF Indus., Inc. v. Koch Pipeline Co., L.P.*, 4 S.T.B. 637, 640 n.11 (2000). The STB no longer appears to have its copy of Koch's filing containing this argument, so the author is relying on the Board's published characterization. *Id.*

321. *Id.* (continuing: "and our jurisdiction over [anhydrous ammonia] is now settled.") (citing *Gulf Cent. Pipeline Co.*, 7 I.C.C.2d 52, 56-58 (1990); CF Indus., Inc. v. FERC, 925 F.2d 476 (D.C. Cir. 1991); H.R. REP. NO. 104-422, at 230 (1st Sess. 1995) (Conf. Rep.)).

322. *See* Brief for Petitioner Koch Pipeline Co. L.P., *CF Indus., Inc. v. STB*, Case Nos. 00-1209, 00-1213, 00-1248, 2001 WL 36039073 at *6 n.1 (D.C. Cir. Mar. 9, 2001) (noting that "[STB] has jurisdiction over the pipeline transportation of commodities 'other than water, gas, or oil.' Even though [anhydrous ammonia] is a gas in its natural state, the ICC, predecessor to the Board, determined that it, not FERC, had jurisdiction over [anhydrous ammonia] pipelines because [anhydrous ammonia] is not energy-related.") (citing 49 U.S.C. § 15301(a); *Gulf Central*, 7 I.C.C.2d at 56-58) (current Supreme Court Chief Justice John Roberts briefed and argued the case for the pipeline petitioner).

323. CF Indus., Inc. v. STB, 255 F.3d 816, 818 (D.C. Cir. 2001) (citing *CF Indus., Inc. v. FERC*, 255 F.3d at 478).

324. *Cortez Pipeline Co.*, 45 Fed. Reg. 85,177, at 85,178 (I.C.C. Dec. 24, 1980).

325. Jada F. Garofalo & Madeleine Lewis, *Sources to Sinks: Expanding a National CO2 Pipeline Network*, 50 ENVT'L L. REP. 10057, 10062 (2020); Wendy B. Jacobs & Michael Craig, *Legal Pathways to Wide-*

ers note inconsistencies with *Cortez* and later government publications that assume STB jurisdiction over carbon dioxide pipelines.[326] None appear to have noted this particular STB decision that disclaims the logic of the *Cortez* decision. This explicit rejection of the *Cortez* logic in a fully litigated proceeding should be a sound basis to conclude that, as soon as the STB faces the issue, carbon dioxide pipelines will be found to be regulated and that no gap exists between any of the NGA, the ICA, or ICCTA regulatory regimes.

b. Carbon Dioxide Pipelines Will Likely be Found Subject to ICCTA Regulation When the STB Next Addresses the Issue

The *Cortez* holding has not been specifically overruled regarding carbon dioxide pipelines.[327] However, as described above, the logic behind its disclaimer—that the ICC (now STB) lacks jurisdiction over "all gas types regardless of origin or source"[328]—has been directly abandoned. It therefore seems most likely that carbon dioxide pipelines will be found jurisdictional when the issue next arises. As new pipelines come online to transport captured carbon dioxide to points of sequestration or utilization, the STB will likely face the question of jurisdiction again.[329] There are many ways this issue could arise. A carbon diox-

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spread Carbon Capture and Sequestration, 47 ENVT'L L. REP. News & Analysis 11022, 11039 (2017); Philip M. Marston & Patricia A. Moore, *From EOR to CCS: The Evolving Legal and Regulatory Framework for Carbon Capture and Storage*, 29 ENERGY L.J. 421, 453 (2008) (concluding that "it seems clear under current law that the interstate transportation of supercritical CO2 by pipeline is not subject to STB regulation under the ICA" despite the fact that the GAO had found otherwise); Harry L. Reed, *The New Carbon Dioxide Pipelines: Revival of the Common Carrier at Common Law*, 12 OKLA. CITY U. L. REV. 103 (1987) (arguing that the *Cortez* disclaimer returned carbon dioxide pipelines to being common carriers at common law).

326. CHARLES F. CALDWELL & CARLY L. KIDNER, CARBON DIOXIDE PIPELINES: REGULATORY AND COMMERCIAL ISSUES IN CARBON CAPTURE, UTILIZATION, AND SEQUESTRATION, CALDWELL BOUDREAUX LEFLER PLLC 10-11 (2021), https://www.cblpipelinelaw.com/news/articles/Carbon-Dioxide-Pipelines-Regulatory-Commercial=Issues-Carbon-Capture-Utilization-Sequestration.pdf; MATTHEW WALLACE ET AL., A REVIEW OF THE CO2 PIPELINE INFRASTRUCTURE IN THE U.S. 31-32 (2015), U.S. DEP'T OF ENERGY, https://www.energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdfl; Jonas J. Monast et al., *A Cooperative Federalism Framework for CCS Regulation*, 7 ENV'T & ENERGY L. & POL'Y J. 1, 24 (2012); ADAM VANN ET AL., CONG. RSCH. SERV, LEGAL ISSUES ASSOCIATED WITH THE DEVELOPMENT OF CARBON DIOXIDE SEQUESTRATION TECHNOLOGY 4-5 (2008); Robert R. Nordhaus & Emily Pitlick, *Carbon Dioxide Pipeline Regulation*, 30 ENERGY L.J. 85, 90-95 (2009); ADAM VANN & PAUL W. PARFOMAK, CONG. RSCH. SERV., REGULATION OF CARBON DIOXIDE (CO_2) SEQUESTRATION PIPELINES: JURISDICTIONAL ISSUES 4-5 (2008); *see also id.* 6 n.29 (noting the inconsistencies between the GAO Report at *Cortez* and relaying a communication from STB Public Affairs indicating knowledge of this conflict but stating the STB "likely not act to resolve this conflict unless a CO_2 pipeline dispute comes before it."). *See also* Tara K. Righetti, *Siting Carbon Dioxide Pipelines*, 3 ONE J 907, 929-30, 970-71 (2017) (imputing the ICC's *Cortez* order to FERC's ICA authority and discussing whether STB would disclaim authority over carbon dioxide pipeline rates rates).

327. *See* VANN & PARFOMAK, *supra* note 326, at 6 n.29 (noting the inconsistencies between the GAO Report and *Cortez* Order and relaying a communication from STB Public Affairs indicating knowledge of this conflict but stating the STB "likely not act to resolve this conflict unless a CO_2 pipeline dispute comes before it.").

328. 45 Fed. Reg. at 85,178.

329. For instance, there are two interstate pipelines centered on Iowa being developed to carry captured carbon dioxide for sequestration or utilization. Press Release, *Public Informational Meetings on the Proposed Summit Carbon Pipeline*, IOWA UTILS. BD. (Oct. 15, 2021), https://iub.iowa.gov/press-release/2021-10-15/public-informational-meetings-proposed-summit-carbon-pipeline; Press Release, *Public Informational*

ide pipeline's shipper could file a complaint at the STB challenging the rates or practices as discriminatory or unreasonable.[330] In particular, a shipper with few options may have entered into a contract with a pipeline that includes unreasonable rates, or unequal terms with other shippers, and may seek to have the contract altered or rescinded. Or, just as likely, a would-be shipper could file a complaint if a pipeline refuses to provide it with transportation services.[331] In addition, carbon dioxide pipelines could file a petition at the STB, requesting exemption from certain requirements of ICCTA.[332] Conclusively establishing jurisdiction will help resolve any regulatory uncertainty still associated with this increasingly important infrastructure. Of particular importance, contracts for transportation on common carriers are disfavored and, when permitted, subject to scrutiny.[333] Obtaining such clarity sooner may be especially important because, unlike with FERC's oil pipeline regime, it is unclear what, if any, contracts for ICCTA pipeline transportation service are legal.[334]

D. Conclusion: All Interstate Pipelines Are Regulated

The pipeline regulatory framework was developed over a century by four agencies, numerous presidents and Congresses, and the appellate courts. The result, in line with legislative intent, is a comprehensive regulatory framework with three conterminous regulatory regimes. The delineation between these regimes had clear and ready meaning when set against the backdrop of a fossil fuel-based economy. As renewable fuels matured economically, this delineation proved more complex. But ultimately, the agencies handled this complexity to reach relatively clear rules. The current precedent can be distilled to a short test of a few questions to categorize any product, including biomethane, renewable liquid fuels, carbon dioxide, and hydrogen.

This analysis may also provide insight into the regulation of yet-to-be-developed energy commodities. Renewable fuels are being pursued with appro-

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Meetings Continue for Proposed Navigator Pipeline, IOWA UTILS. BD. (Jan. 6, 2022), https://iub.iowa.gov/press-release/2021-10-27/iub-sets-37-public-informational-meetings-proposed-navigator-pipeline.

330. 49 U.S.C. §§ 15501(a), 15505.

331. 49 U.S.C. § 15701(a); 49 C.F.R. § 1305.3 (2019). One of the key differences between the FERC and STB regimes is that pipelines regulated by STB are not required to file tariffs. However, ICCTA and the STB's implementing regulations provide shippers relatively detailed rights to have a pipeline's rates for transportation provided and established upon request, including where the pipeline does not yet provide certain services. *See* 49 U.S.C. § 15701(a); 49 C.F.R. § 1305.3. *See also* William G. Bolgiano & Matthew Field, *Federal Regulation of Interstate Hydrogen Pipelines,* VENABLE (May 6, 2021), https://www.venable.com/-/media/files/publications/2021/05/whitepaper_hydrogen_pipelines.pdf.

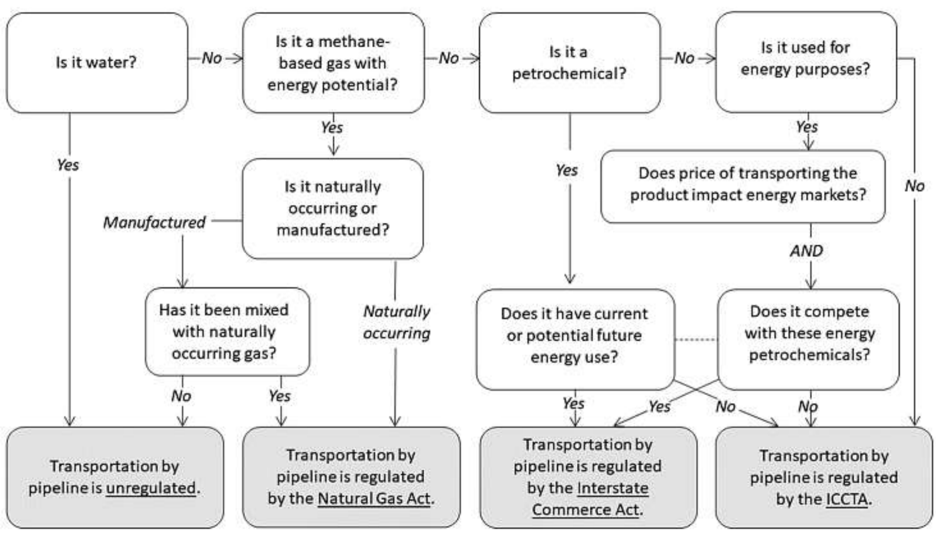
332. 49 U.S.C. § 15302(a)-(a)(1).

333. *See, e.g.*, Sea-Land Serv., Inc. v. ICC, 738 F.2d 1311, 1316 (D.C. Cir. 1984) (noting that contracts were once considered inherently discriminatory but had been permitted by the ICC "provided that the carrier offering them makes them available to all similarly situated shippers of like commodities."). *See also ONEOK Elk Creek Pipeline L.L.C.*, 167 FERC 61,277 (2019) (Glick, Comm'r, concurring) (current FERC Chair stating oil pipeline contracts are "meant to be the exception" and urging FERC to reexamine its policies for approving them).

334. *See Dyno Nobel, Inc. v. NuStar Pipeline Operation P'ship, L.P.*, Docket No. NOR 42147, 2017 WL 1104830, at *4 n.7 (S.T.B. Mar. 24, 2017) (noting the ICCTA pipeline statute does not provide for contract as it does for other regulated industries); *see also Mapco Ammonia Pipeline Inc.*, No. 41582, 1995 WL 434276 (I.C.C. July 18, 1995) (declining to issue declaratory order regarding contract rate structure).

priate urgency, and this article cannot address all the new candidates. However, the framework articulated here can inform the new jurisdictional discussions as they emerge. For instance, carbon dioxide can be combined with hydrogen and turned into hydrocarbon fuels through the Fischer-Tropsch process.[335] If that technology becomes economical, will carbon dioxide be considered an energy commodity? Further, ammonia, the quintessential *non*-energy pipelined product, is now increasingly seen as a promising renewable fuel, especially for maritime transportation.[336] Would seaward ammonia pipelines be regulated by FERC with inland ones regulated by the STB? Such questions will be addressed as the technologies mature, but the test presented in this article should provide a starting point for that analysis.

IV. THE PIPELINE COMMODITY JURISDICTIONAL TEST



For any commodity, only a handful of questions need to be answered to determine how interstate pipelines carrying that commodity are regulated. The first question to ask is whether the commodity is water. This article devotes little discussion to interstate water pipelines because little analysis is required—they are all exempt from federal economic regulation. That is not to suggest they are unimportant. Long distance water pipelines may play an important role in adapting

335. *Fisher-Tropsch Synthesis*, NAT'L ENERGY TECH. LAB'Y, https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/ftsynthesis.

336. *See* Nils Rokke, *Ammonia A Sustainable Option For Shipping*, FORBES (Oct. 5, 2021), https://www.forbes.com/sites/nilsrokke/2021/10/05/ammonia-a-sustainable-fuel-option-for-shipping/?sh=529588c67c00; Maria Gallucci, *Why the Shipping Industry Is Betting on Ammonia*, ICCE.org,https://spectrum.ieee.org/why-the-shipping-industry-is-betting-big-on-ammonia; ALL ABOARD: HOW THE BIDEN HARRIS ADMINISTRATION CAN HELP SHIPS KICK FOSSIL FUELS, OCEAN CONSERVANCY 23 (2021), https://oceanconservancy.org/wp-content/uploads/2021/04/All-Aboard-US-Policy-Zero-Emissions-Report_FINAL.pdf (recommending hydrogen and ammonia over other fuels for long range maritime shipping).

to climate change.[337] While there has been no precedent applying this exemption to the Hepburn Act, it appears safe to assume it should be read narrowly not to include mixtures of water and other materials. For instance, we know that pipelines carrying slurries of coal and water are regulated by the STB under ICCTA because Congress chose not to transfer them to FERC in the DOE Act.[338]

If the product is not water, the next question to answer is whether it is a methane-based gas. If it is, we next need to know whether the methane component occurs naturally or is manufactured. If the methane occurs naturally, then pipelines carrying the commodity are subject to regulation under the NGA. Conventional natural gas extracted from reservoirs is the archetypical, and perhaps only, example of this. We need to be mindful that this gas may include other commodities mixed with the methane, such as butane or carbon dioxide. If any of those elements are isolated and removed from this methane gas stream, this analysis begins again.

If the methane in the gas is manufactured, the next question to answer is whether that artificial gas has been mixed with naturally occurring methane. If it has been mixed, then the mixed gases are subject to NGA regulation. If not, pipelines carrying the unmixed, manufactured methane are unregulated. Coal gas is the archetypical manufactured gas. Renewable sources of methane, such as methane made in controlled anaerobic digestion would likely be considered manufactured as well. The status of landfill gas remains uncertain.

If the commodity carried by the pipeline is not water and does not contain significant amounts of methane, it will be subject to one of the two iterations of the Hepburn Act—FERC's ICA or the STB's ICCTA. To place the product in one regime or the other, we next need to determine whether the commodity is a petrochemical or derivative. If it is, the next question is whether it has potential energy applications. If the product is a petrochemical derivative and it has energy applications, its transportation is regulated by FERC under the ICA. Crude oil and finished products such as gasoline, diesel, and jet fuel are the archetypical energy petrochemicals subject to the ICA. If the petrochemical derivative does not have potential energy applications, the commodity is subject to ICCTA's similar regulatory regime.[339] The typical ICCTA petrochemical is a feedstock resource, such as propylene, that has been processed past the point of having practical or safe energy uses.

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337. *See, e.g.*, DENISE FORT, BARRY NELSON, NAT'L RES. DEF. COUNCIL, PIPE DREAMS: WATER SUPPLY PIPELINE PROJECTS IN THE WEST (2012), https://www.nrdc.org/sites/default/files/Water-Pipelines-report.pdf. Interstate water pipelines, as discussed above, have been around since before any pipeline regulation and they remain relevant today. For instance, Utah is actively pursuing a project called the "Lake Powell Pipeline," a 120-mile pipeline that would cross the border with Arizona in three places. *Id.* at 31.

338. *See Gulf Cent. Pipeline Co*, 7 I.C.C.2d 52, 58 (1990); *Gulf Cent. Pipeline Co.*, 50 FERC ¶ 61,381, at pp. 62,165-66 (1990).

339. One open question is whether non-energy petrochemicals would be jurisdictional if they share pipeline space with energy petrochemicals. FERC has so far only disclaimed jurisdiction over non-energy petrochemicals that do not use the same pipelines as energy products. *See Enterprise Lou-Tex Propylene Pipeline L.P.*, 111 FERC ¶ 61,068 at P 11 (2005); *Sabine Propylene Pipeline L.P.*, 109 FERC ¶ 61,025 at P 9 (2004); *Texaco Petrochemical Pipeline LLC*, 107 FERC ¶ 61,151 at P 3 (2004).

Finally, pipelines carrying any remaining non-water, non-methane, non-petrochemical products are likely subject to ICCTA's catch-all jurisdiction. For instance, fertilizer pipelines carrying ammonia or phosphates are regulated by the STB. However, there is an important exception. If the commodity is used for energy *and* it directly competes with one of the energy petrochemicals regulated by FERC, then FERC will regulate it as "oil" notwithstanding its renewable origins. This principle has so far only been applied to ethanol. If a commodity is used for energy purposes but does not compete with petrochemical fuels, for instance coal slurry, then the transportation of that commodity by pipeline is subject to ICCTA and not the ICA.

A. Case Study: The Ethane Molecule

These shifting jurisdictional determinations can be illustrated by the journey of the typical ethane molecule, which is subject to each pipeline regulatory regime as it moves from its home underground on its way to be sold as plastic to consumers. Ethane is a gas at room temperature and, after methane, is the second most prominent component of natural gas. When natural gas is extracted it includes many non-methane elements (so-called "natural gas liquids"), including ethane. Pipelines carrying this "wet" natural gas are still subject to the NGA because the gas contains significant amounts of naturally occurring methane.[340] Some ethane remains in the natural gas stream through to combustion. But most of the ethane is pulled out of the gas stream as soon as it is economical to do so. That ethane is now no longer subject to the NGA because it is no longer commingled with methane. Most of this ethane will eventually be turned into plastics. However, it still *might* be used as fuel (it's a slightly more potent fuel than methane).[341] For that reason, and because it comes from a petroleum source, it is subject to FERC's ICA jurisdiction.[342] After this ethane is piped by itself to a refinery, most of it will be converted to ethylene, the next step on its way to becoming polyethylene, the ubiquitous plastic. However, unlike ethane, ethylene has no practical energy applications and can only really be turned into plastic. Thus, at this point in its journey, the transportation of ethylene by pipeline becomes subject to the STB's regulation under ICCTA.[343]

340. *See Columbia Gas Transmission Corp.*, 17 FERC ¶ 61,020, at p. 61,036 (1981) ("Although ethane is itself nonjurisdictional, the sale or transportation of vaporized ethane which is commingled with natural gas is subject to Commission jurisdiction.").

341. *Id.* at 61,035. Because of this the main fuel use of ethane is to blend it into a natural gas stream to increase its heat content. When this is done, the ethane in that gas stream becomes subject to the NGA once again.

342. *Williams Olefins Feedstock Pipelines, L.L.C.*, 145 FERC ¶ 61,303 at P 23 (2013) ("the Commission concludes that it has [ICA] jurisdiction over the interstate transportation of purity ethane. It is unquestionably a naturally-occurring hydrocarbon that is used for current energy purposes and will be used for future purposes.").

343. *Texaco Petrochemical*, 107 FERC ¶ 61,151 at P 5 ("if a hydrocarbon product shipped by an oil pipeline is not used for energy purposes, the Commission lacks jurisdiction over the transportation of that product. Based on the more detailed information provided here, the Commission concludes it lacks jurisdiction over the transportation of ethylene by interstate oil pipeline and authority over such transportation rests with the [Surface Transportation] Board.").

The example of ethane provides a model for the analysis of hydrogen's jurisdictional status. Hydrogen is primarily a fossil-derivative and will remain so in large part for the foreseeable future. Hydrogen can be found with natural gas and blended into methane pipeline streams, which would be subject to the NGA. Once hydrogen is isolated it is still used primarily for energy purposes (explained below), so dedicated hydrogen-only pipelines should then be subject to the ICA. Finally, some hydrogen will be turned into another product, such as ammonia, that has no current energy applications. Only after this transformation would the pipelines carrying this new commodity be regulated by the STB under the ICCTA's catch-all jurisdiction.

V. IMPLICATIONS OF REGULATION UNDER THE DIFFERENT REGIMES

This article is focused on the question of how regulatory jurisdiction is determined based on the commodity being shipped. Still, a quick summary of the more substantive differences between the three (really two) regulatory regimes is warranted. Both Hepburn Act cognates (the ICA and ICCTA) are virtually identical in terms of statutory substance and jurisdictional scope.[344] So, unless stated otherwise, this section compares the NGA against the general Hepburn Act common carrier regime.

A. *Similarities Between the Two Regulatory Paradigms*

While the NGA and Hepburn regimes are very distinct, they do have some similarities. As described above in sections III.A.1 and III.A.2, both statutes were meant to remedy a similar problem. To that end, both regimes prohibit discrimination by pipelines.[345] Similarly, both regimes require pipelines to charge reasonable rates.[346] Hepburn Act pipelines are also required to operate as "common carriers" which means they must provide transportation services to any shipper upon reasonable request.[347] Natural gas pipelines, in contrast, are "con-

344. *See, e.g.*, CF Indus., Inc. v. FERC, 925 F.2d 476, 477 (D.C. Cir. 1991) ("At oral argument we gained the impression that petitioner CF Industries (unlike its competitor Farmland, which did not petition for review) wished FERC, rather than the ICC, to assert jurisdiction over Gulf Central Pipeline's transportation of anhydrous ammonia merely because FERC was perceived in some undefined way as the more 'hard-nosed' regulator."). *See* Bolgiano & Field, *supra* note 331, for a more granular comparison of the (mostly procedural) differences between the STB and FERC common carrier pipeline regimes.

345. 15 U.S.C. § 717c(b); 49 U.S.C app. § 3(1); 49 U.S.C. § 15505.

346. 15 U.S.C. § 717c(a); 49 U.S.C app. § 1(5); 49 U.S.C. § 15501(a).

347. *See* 49 U.S.C. app. § 1(4) ("It shall be the duty of every common carrier subject to this chapter to provide and furnish transportation upon reasonable request therefor"); *see also Colonial Pipeline Co.*, 156 FERC ¶ 61,001 (2016) (rejecting tariff provision that appeared to exclude new shippers); 49 U.S.C. § 15701(a). *See also* Makholm & Olive, *supra* note 72 (comparing NGA and ICA carrier obligations); Christopher J. Barr, *Unfinished Business: FERC's Evolving Standard for Capacity Rights on Oil Pipelines*, 32 ENERGY L.J. 563 (2011) (same).

tract carriers,"[348] although for the last few decades, FERC's regulation of natural gas pipelines has focused on encouraging open transportation.[349]

This article is focused on the reach of pipeline regulation to the transportation of emerging commodities. So, the focus of this comparison will be on their different jurisdictional reaches under the different regimes as well as FERC's regulation of siting of pipelines and, in particular, its experience facilitating the conversion of pipelines from one regime to the other.

B. Different Scopes of Jurisdiction

In addition to the transportation of certain commodities, jurisdiction is also contingent on the physical layout and operation of the pipelines as well as the economic arrangements of the transportation. In general, the NGA has broader jurisdictional scope than the ICA on these points. However, there are some pipeline arrangements that would fall under the jurisdiction of the Hepburn Act without falling under the jurisdiction of the NGA, were they carrying natural gas.

Pipelines located entirely within one state may still be found to be jurisdictional under the NGA and Hepburn Act frameworks, but under different circumstances. In the Hepburn Act framework, whether transportation is interstate (or international) turns on the essential character of the commerce from the perspective of the shipper.[350] In contrast, under the NGA, pipelines that receive gas from an interstate pipeline are engaged in interstate commerce for purposes of the NGA unless they fall within the Hinshaw Amendment exception, which covers the transportation of "natural gas received by such person from another person within or at the boundary of a State if all the natural gas so received is ultimately consumed within such State."[351] The NGA also does not cover pipelines that are engaged in international (but not interstate) transportation.[352]

The NGA and Hepburn Act frameworks also have different exceptions to jurisdiction for pipelines that cross state lines. For Hepburn Act pipelines, *The Pipe Line Cases* created a narrow exception called the "Uncle Sam" rule.[353] This principle is named for the Uncle Sam Oil Company, whose pipeline crossed state

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348. CRS REPORT, *supra* note 51, at 9. *See* Makholm & Olive, *supra* note 72, at 419 (citing Order No. 636, *Pipeline Serv. Obligations & Revisions to Reguls. Under Pt. 284; Regul. of Nat. Gas Pipelines After Partial Wellhead Decontrol*, 59 FERC ¶ 61,030 (1992); Order No. 637, *Regulation of Short-Term Nat. Gas Transp. Serv., & Regul. of Interstate Nat. Gas Transp. Servs.*, 90 FERC ¶ 61,109 (2000)).

349. JEFF D. MAKHOLM, THE POLITICAL ECONOMY OF PIPELINES: A CENTURY OF COMPARATIVE INSTITUTIONAL DEVELOPMENT 140-49 (2012) (describing the shift to regulation focused on transportation).

350. *Aircraft Serv. Int'l Grp. v. Cent. Fl. Pipeline LLC*, 169 FERC ¶ 61,119 at P 145 (2019), *aff'd sub nom.* Aircraft Serv. Int'l, Inc. v. FERC, 985 F.3d 1013, 1020 (D.C. Cir. 2021). The test is derived from Supreme Court and ICC precedent that predates the DOE Act. The STB has yet to apply this test regarding its pipelines, but undertakes a similar analysis in determining whether rail movements are interstate or intrastate. *See Texas Cent. R.R. & Infrastructure, Inc*, slip. op. at 7, Docket No. FD 36025 (S.T.B. Jul. 16, 2020).

351. 15 U.S.C. § 717(c).

352. *Nexus Gas Transmission, LLC*, 172 FERC ¶ 61,199 at P 15 n.32 (2020) ("in limited scenarios, gas could be exported directly from a production area in a border state without ever entering interstate commerce.") (citing Border Pipe Line Co. v. FPC, 171 F.2d 149, 151 (D.C. Cir. 1948); *Trans-Pecos Pipeline, LLC*, 155 FERC ¶ 61,140 at P 31 (2016)). *See also* Big Bend Conservation All. v. FERC, 896 F.3d 418, 421 (D.C. Cir. 2018).

353. The Pipe Line Cases, 234 U.S. 548, 561-62 (1914).

lines but only transported crude oil from the Uncle Sam well to the Uncle Sam refinery. Writing for the Court, Justice Holmes compared extending jurisdiction over such a pipeline to saying that a "man was engaged in the transportation of water whenever he pumped a pail of water from his well to his house."[354] This narrow exception is rarely invoked successfully.[355] For NGA pipelines, section 311 of the NGPA[356] allows FERC to exempt local distribution companies from NGA regulation even if their pipelines cross state boundaries.[357] There is no such exemption for Hepburn Act common carriers.[358]

C. Different Siting Authority and Preemption

Perhaps the biggest difference between the NGA and Hepburn Act regimes is the federal government's role in pipeline siting and construction. Siting, construction, and abandonment of NGA pipelines is comprehensively regulated. Under the NGA, gas pipelines must seek a certificate from FERC for their construction which, if granted, comes with eminent domain authority.[359] Further, NGA pipelines cannot commence or abandon their transportation services (including through a lease) without FERC approval.[360] In contrast, FERC has no authority over oil pipelines' entry or exit from the market, or their constrution.[361]

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354. *Id.* at 562. There is an interesting and short concurrence by Chief Justice White arguing that this exemption is not actually contained in the statute but is required by the Constitution's Takings Clause. *Id.* at 562-63 (White, J., concurring).

355. Valvoline Oil Co. v. United States, 308 U.S. 141, 146-47 (1939); *Hunt Refin. Co.*, 70 FERC ¶ 61,035, at p. 61,111 (1995) (finding Uncle Sam exception did not apply where oil wells owned by other producers could access applicant pipeline); *Nobel Energy, Inc.*, 150 FERC ¶ 61,073 at P 13 (2015) (denying pipeline's request for a related but less onerous temporary waiver of tariff filing requirements where the pipeline "failed to demonstrate unambiguously that it will own 100 percent of the production to be transported"); *Ashley Creek Phosphate Co. v. Chevron Pipe Line Co.*, Docket No. 40131, 1988 WL 226402, at *32-33 (I.C.C. May 31, 1988), *rev'd* 5 I.C.C.2d 303, *clarified* 5 I.C.C.2d 1064 (1989) (administrative law judge saying the argument was "sensibly abandoned" and applies only "where it is known in advance that no other shipper will want or need to ship" on the pipeline); *id.* at *33 ("It is not for owner-shippers, however, to arrogate such exceptions to themselves. They must make application therefor to the regulatory agency, upon a showing that no other potential shipper could or would desire service.").

356. 15 U.S.C. § 717f(f).

357. *See, e.g.*, *CenterPoint Energy Res. Corp.*, 168 FERC ¶ 62,011 at P 18 (2019), *modified* 176 FERC ¶ 62,157 (2021).

358. *Valvoline Oil Co.*, 308 U.S. at 146-47 ("it is the purchase from many sources and subsequent carriage that determine the applicability of the statute . . . . The smallness of the operation is immaterial.").

359. 15 U.S.C. § 717f(h).

360. 15 U.S.C. § 717f(b).

361. *See, e.g.*, *SFPP, L.P.*, 140 FERC ¶ 61,220 at P 50 n.72 (2012) ("Under section 7(c) of the [NGA] a natural gas pipeline must obtain a certificate of public convenience and necessity prior to construction or expansion; and the Commission has conditioned its finding of 'public convenience and necessity' . . . However, under the [ICA], there is no similar obligation for an oil pipeline to seek Commission certification prior to construction or expansion."); *see also Rocky Mountain Pipeline Sys. LLC*, 126 FERC ¶ 61,301 at P 9 (2009); *Plantation Pipe Line Co.*, 104 FERC ¶ 61,271 (2003); *Mid-America Pipeline Co.*, 131 FERC ¶ 61,012 at P 11 (2010). One oil pipeline, the Trans Alaska Pipeline System, was authorized by a specific act of Congress. Trans-Alaska Pipeline Authorization Act§ 202, Pub. L. 93-153, 87 Stat. 576, 584 (1973) (codified as amended at 43 U.S.C. § 1651 (2022)).

The only federal control over oil pipeline siting at all is the rare requirement for a presidential permit to commence service on a cross-border pipeline.[362]

This lack of federal siting authority has not been an insurmountable barrier to construction of Hepburn Act pipelines. Some commenters have expressed concern that hydrogen pipelines would need or benefit from NGA-style siting authority in order to achieve the necessary proliferation.[363] However, as demonstrated by the extensive non-gas pipeline network, federal siting authority is not crucial, though it could be beneficial.[364] While FERC has no siting authority for oil pipelines, it does grant pipelines preliminary approval of (otherwise legally suspect) committed contract rate structures for new capacity, on the theory that new infrastructure might not be developed but for these contracts.[365] FERC's practice of approving contracts for oil transportation has not yet been subject to judicial review.[366] Nevertheless, this policy has influenced oil pipeline infrastructure development for decades.[367]

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362. *See generally* Valerie L. Chartier-Hogancamp, *Fairness and Justice: Discrepancies in Eminent Domain for Oil and Natural Gas Pipelines*, 49 TEX. ENV'T L.J. 67 (2019).

363. Bowe & Rice, *supra* note 64 ("It might be logical to develop a federal process for approval of interstate hydrogen pipelines that would be analogous to the NGA certification process"); *see also* K&L GATES LLP, THE H2 HANDBOOK 59-60 (2020), https://www.klgates.com/epubs/h2-handbook/index.html (noting the advantages of a federal certificate for pipeline construction) [hereinafter THE H2 HANDBOOK].

364. Klass & Meinhardt, *supra* note 77, at 1026 (concluding that while the "one-stop shopping with FERC for natural gas pipelines has allowed extensive new construction of natural gas pipelines on the east coast and in Texas to accommodate new sources of shale gas. . . . the state-centered process for siting oil pipelines also appears to accommodate sufficient construction of oil pipelines to meet new demand. Most states do not have very onerous siting or eminent domain procedures for oil pipelines, and the high price of oil has led to very favorable market conditions for building those pipelines to transport oil to markets."). In another sector of national importance—electric transmission—the federal government also lacks siting authority. While the grid has been built without federal permits, the lack of siting authority has been controversial, and is viewed as a contributing factor to reliability issues, as well as a barrier to renewable energy transmission. *See, e.g.*, Alexandra B. Klass & Jim Rossi, *Reconstituting the Federalism Battle in Energy Transportation*, 41 HARV. ENV'T L. REV. 423 (2017); Luke Franz, *Electric Transmission Lines as a Gateway to Renewable Energy: The Power Rests with the States*, 33 NOTRE DAME J.L. ETHICS & PUB. POL'Y 471 (2019); Alexandra B. Klass, *Expanding the U.S. Electric Transmission and Distribution Grid to Meet Deep Decarbonization Goals*, 47 ENV'T L. REP. News & Analysis 10749 (2017).

365. *See Express Pipeline P'ship*, 75 FERC ¶ 61,303, *aff'd* 76 FERC ¶ 61,245 (1996). *See also Colonial Pipeline Co.*, 146 FERC ¶ 61,206 at P 38 (2014); *North Dakota Pipeline Co. LLC*, 147 FERC ¶ 61,121 at P 22 (2014); Daniel S. Arthur & Michael R. Tolleth, *FERC's Policies Are Incentivizing the Exercise of Market Power through under-Development of Oil and Natural Gas Liquids Pipeline Capacity*, 42 ENERGY L.J. 149 (2021).

366. Though not subject to judicial review directly, FERC's oil pipeline contract regime was influenced by a D.C. Circuit opinion holding that contract rates were not *per se* unlawful. *Express Pipeline P'ship*, 76 FERC ¶ 61,245 at 62,254 (quoting Sea-Land Serv., Inc. v. ICC, 738 F.2d 1311, 1316 (D.C. Cir. 1984)). In the event its contract policy is ever reviewed by a court, FERC may face some interesting questions—for instance, why can contracts for committed service on an oil pipeline be higher than the cost-of-service, without a showing that the pipeline lacks market power. *See ONEOK Elk Creek Pipeline L.L.C.*, 167 FERC ¶ 61,277 at P 6 (Glick, Comm'r, concurring) (expressing concern that "a pipeline which has market power can establish a higher rate through 'negotiation.'") (citations omitted). FERC may also be asked why it does not consider the environmental impacts of these new pipelines even though its rationale for endorsing these contracts hinges on FERC's approval of them being the but-for causation of new pipeline development. *See, e.g.*, *TransCanada Keystone Pipeline, LP*, 125 FERC ¶ 61,025 at P 18 (2008) (approving certain contract terms because "Keystone and its shippers need assurances through the Commission's declaratory order process to justify the significant financial commitments necessary to complete the project."); *Transcontinental Gas Pipe Line Co., LLC*, 164

VI. FERC'S AUTHORITY TO REGULATE HYDROGEN PIPELINES

Applying the jurisdictional test to hydrogen involves many facets of the test but could ultimately prove straightforward. In this analysis, we should begin with the present sources and applications of hydrogen while being mindful of changing balance of sources and uses moving toward a net-zero landscape. The diversity of hydrogen's sources and applications could potentially implicate all three pipeline regulatory regimes. Ultimately, hydrogen can be understood to be much like the ethane molecule, discussed above. It is presently derived from fossil fuels and will likely remain so in large part for the foreseeable future. It could be transported mixed with methane in pipelines subject to the NGA, but it is not subject to that act when transported alone. When transported by itself, it should be considered subject to the ICA because of its fossil origins and energy applications. Renewable (non-fossil) hydrogen would still be subject to FERC's jurisdiction because it competes directly with fossil energy commodities.[368] Only when hydrogen is transformed beyond an energy use (for instance, into ammonia) should its transportation be regulated under ICCTA.

This proposal reflects a departure from the current majority view, which is that hydrogen is regulated by the STB under ICCTA.[369] However, this view appears to be based on a misconception about hydrogen's uses. As described below, hydrogen's fundamental use is for energy. Most hydrogen made today is put into oil refineries and most of that hydrogen becomes—at the molecular level—a part of the refineries' finished products and is ultimately burned to power our internal combustion and jet engines. And as a powerfully needed renewable fuel, hydrogen's energy applications will only grow. Further, government policy, including the recent infrastructure bill, recognizes that hydrogen is an important energy resource. Therefore, FERC is the more appropriate regulator of hydrogen pipelines.

A. Hydrogen is Not Subject to the NGA, Unless It Is Blended with Natural Gas

Many who speculate about how to regulate hydrogen pipelines invoke the NGA.[370] Most acknowledge that hydrogen would not itself be subject to the NGA, but the transportation of hydrogen mixed with natural gas would be. This

FERC ¶ 61,101 (2018) (Glick, Comm'r, dissenting in part) (dissenting from FERC approval of gas pipeline to extent it did not consider the project's upstream and downstream greenhouse gas impacts).

367. *See generally* Arthur & Tolleth, *supra* note 365.

368. *See* section VI.B.3 below.

369. CRS REPORT, *supra* note 51, at 10 ("Jurisdiction over rates for interstate hydrogen pipelines resides with the Surface Transportation Board (STB)."); Hydrogen Economy Statement, *supra* note 65, at 618 ("The statement recognizes that the Surface Transportation Board (STB), the Federal economic regulator of railroads, also regulates economic aspects of interstate hydrogen pipelines."); GAO REPORT, *supra* note 65, at app. I.

370. *See, e.g.*, Bowe & Rice, *supra* note 64 ("It might be logical to develop a federal process for approval of interstate hydrogen pipelines that would be analogous to the NGA certification process."); VINSON & ELKINS LLP, *Federal Hydrogen Regulation in the United States: Where We Are and Where We Might be Going* (Dec. 9, 2020), https://www.velaw.com/insights/federal-hydrogen-regulation-in-the-united-states-where-we-are-and-where-we-might-be-going/; MORGAN LEWIS & BOCKIUS LLP, *Considerations For Transporting A Blended Hydrogen Stream In Interstate Natural Gas Pipelines* (Jun. 11, 2021), https://www.morganlewis.com/pubs/2021/06/considerations-for-transporting-a-blended-hydrogen-stream-in-interstate-natural-gas-pipelines.

seems the most reasonable conclusion for the first step of the analysis. In fact, this opinion was recently expressed by FERC's Chair.[371] In this way, hydrogen's jurisdictional analysis is much like ethane's.

1. Hydrogen Pipelines Are Not Subject to the NGA Because Hydrogen is Not a Methane-Based Gas

Hydrogen is one of the two components of methane (CH_4). Pure hydrogen (H_2), of course, does not contain any methane. As detailed above in, the lack of any methane is dispositive of NGA jurisdiction.[372] Most hydrogen made today is derived from natural gas, *i.e.*, methane. However, the NGA does not extend to methane derivatives or other elements isolated from the gas stream.[373] Many other commodities that are gathered with natural gas are extracted as soon as practical and not subject to the NGA after that point. Further, the legislative history of the NGA makes clear that hydrogen is its own distinct commodity and was not associated with artificial or natural gas.[374] In addition, the recent Infrastructure Act repeatedly treats hydrogen as distinct from natural gas.[375] Hydrogen should therefore not be understood to be either natural or artificial gas under the NGA.

Because dedicated hydrogen pipelines are not regulated by the NGA, they must be regulated under one of the two current Hepburn Act cognate statutes—the ICA as administered by FERC, or ICCTA administered by the STB. This has many consequences for hydrogen pipelines and a full exploration is beyond the scope of this article. But two are worth mentioning. First, is that construction, siting, and market entry of hydrogen pipelines are all unregulated at the federal level. This lack of regulation cuts both ways for hydrogen pipeline developers. On the one hand, they do not need permission to construct a hydrogen pipeline and begin transportation. On the other hand, they have no federal certificate authority that could preempt burdensome state regulation.[376] Another important distinction is that the Hepburn Act framework has no exemption for local utility pipelines.[377] Therefore, if a gas utility operating under an exemption pursuant to section 311 of the NGPA converted entirely to providing hydrogen, it

371. *See* Letter from Richard Glick, FERC Chairman to Sen. Martin Heinrich 1 (Oct. 26, 2021) [FERC accession number 20211027-4000].

372. *See* section III.C.1.a.

373. *Id.*

374. *See* sections III.A.1 and III.A.3, *supra*, and section VI.C, *infra*.

375. *See, e.g.*, Infrastructure Act § 11401, 135 Stat. at 544 (codified at 23 U.S.C. § 151(a)) (describing "hydrogen fueling infrastructure, . . . *or* natural gas fueling infrastructure") (emphasis added). *See also* United States v. Woods, 571 U.S. 31, 45 (2013) (operative terms connected by the conjunction or are "almost always . . . to be given separate meanings") (quoting Reiter v. Sonotone Corp., 442 U.S. 330, 339 (1979)); *see also* Infrastructure Act § 40502, 135 Stat. at 1,053 (codified at 42 U.S.C. § 18792(e)(2)(A)(iii)) (listing "natural gas and hydrogen") (emphasis added); *id.* § 71101, 135 Stat. at 1,321 (codified at 42 U.S.C § 16091(a)(2)) (defining "alternative fuel" as "liquefied natural gas, compressed natural gas, hydrogen, propane, or biofuels.") (emphasis added); *id.* § 71102, 135 Stat. at 1,325 (listing natural gas and hydrogen separately as alternative fuels for ferries).

376. Although, as discussed below, this has not been a tremendous obstacle for non-NGA pipelines.

377. *See* Valvoline Oil Co. v. United States, 308 U.S. 141, 146-47 (1939) ("The smallness of the operation is immaterial.") (applying the rule of *The Pipe Line Cases*).

may well be subjected to common carriage obligations that are incompatible with its local service obligations.

2. Pipelines Transporting a Blend of Hydrogen and Natural Gas Would Be Subject to the NGA

While the NGA does not apply to hydrogen pipelines, FERC's regulation of NGA pipelines may still implicate hydrogen transportation. Blending hydrogen into natural gas is seen as an attractive short-term solution before more dedicated infrastructure is built.[378] FERC would have jurisdiction over the transportation of this mixture of hydrogen and natural gas.[379] FERC has broad jurisdiction over natural gas quality specifications and would therefore oversee the introduction of hydrogen into NGA jurisdictional pipelines.[380] Just as ethane is added to increase natural gas's energy content,[381] hydrogen could be added to increase its environmental attributes.[382] In addition, previously, the FPC has explicitly factored the need for hydrogen production in its assessment of public need for natural gas transportation.[383] This suggests that FERC may have the authority to consider the need for hydrogen delivery when regulating mixed hydrogen-methane pipelines, including their siting. Of course, dedicated pipelines carrying pure hydrogen would still not be subject to the NGA even if their sole purpose was to deliver that hydrogen to a natural gas pipeline.[384]

This view is consistent with the tentative position expressed by previous commenters.[385] In addition, FERC Chairman Glick recently expressed a similar opinion in response to a recent letter from Senator Martin Heinrich of New Mexico. In that letter, Senator Heinrich asked how FERC "views its role in the regulation of interstate hydrogen transportation and storage."[386] In response, Chairman Glick considered sections 4, 5, and 7 of the NGA.[387] He opined that FERC

378. *See* discussion in section II.C.1.a.

379. *See Columbia Gas Transmission Corp.*, 17 FERC ¶ 61,020, at p. 61,036 (1981).

380. *Natural Gas Interchangeability*, 115 FERC ¶ 61,325 (2006).

381. *Williams Olefins Feedstock Pipelines, L.L.C.*, 145 FERC ¶ 61,303 at P 17 (2013).

382. The complex interaction between this policy objective and the NGA's statutory authority is beyond the scope of the article.

383. Opinion No. 789, *Tenneco Oil Co.*, 57 F.P.C. 1306, 1323 (1977) ("The ALJ found that the proposed uses of this gas for the manufacture of chemicals, ammonia, fertilizer and liquid hydrogen [by NASA] are in the public interest, and indeed the record supports no other conclusion"); *see also Tenneco Oil Co.*, 57 F.P.C. 1340, 1396 n.15 (1977) (initial decision) ("The Presiding Judge suspects that if a very small percentage of the research and development effort and expense devoted to NASA's spectacular accomplishments had been directed to the manufacture of hydrogen from seawater and the fixation of atmospheric nitrogen, using tidal, wind or solar power, we could have all the hydrogen and nitrogen fertilizer we need without using natural gas or other irreplaceable assets. This speculation is outside the scope of this proceeding, however; the Commission can fight only a sort of rear-guard action until the nation is convinced of the need for a comprehensive, all-out energy program.").

384. *See* Opinion No. 284, *Deep S. Oil Co. of Tex.*, 14 F.P.C. 83 (1955), *aff'd sub nom.* Deep S. Oil Co. of Tex. v. FPC, 247 F.2d 882 (5th Cir. 1957).

385. *See, e.g.*, VINSON & ELKINS LLP, *supra* note 370; MORGAN LEWIS, *supra* note 370; THE H2 HANDBOOK, *supra* note 363, at 56-58. *See also* CRS REPORT, *supra* note 51, at 9-10 (noting that FERC can regulate hydrogen content of natural gas pipelines).

386. *See* Letter from Richard Glick, *supra* note 371, at 1.

387. *Id.*

"would maintain its jurisdiction over an interstate natural gas pipeline if that pipeline were to blend some amount of hydrogen into the gas stream."[388] Although this issue has not been addressed, Chairman Glick stated that a gas pipeline's proposal to accommodate hydrogen would be governed by FERC's Policy Statement on Gas Quality and Interchangeability and considered on a case-by-case basis.[389] The Chairman also noted that FERC would consider the transportation of hydrogen in its review of natural gas pipeline permitting, if relevant.[390] While this letter is not binding FERC precedent, it certainly could indicate how the agency's leadership would approach these issues as they arise.

3. Capacity Leases Could Facilitate Transporting Hydrogen Within a Natural Gas Pipeline

There is an important caveat regarding how far FERC's NGA jurisdiction over blended hydrogen and methane should extend. Specifically, one strategy that is being considered is a situation where an NGA-regulated pipeline allows hydrogen to be injected into the pipe at an origin (and thereby blended with natural gas) only so the hydrogen can be isolated and removed from the natural gas at its destination.[391] Depending on the specific facts, the actual service provided by that pipeline could most accurately be described as *the transportation of a commodity other than gas*—which would be covered by the Hepburn Act. FERC does not appear to have addressed any analogous situation previously. However, attempting to regulate this sort of arrangement under the NGA would likely prove unwieldly, if not impossible. For one thing, transporting natural gas *and* hydrogen (as opposed to a uniform mixture) would require pipelines to implement at least two sets of entirely different specifications in their tariffs—one for natural gas and one for hydrogen. This would be unprecedented and likely difficult to justify.[392] For another thing, existing natural gas shippers could rightfully scrutinize this arrangement for numerous cost-of-service or discrimination

388. *Id.* at 2.

389. *Id.* at 2-3 (citing *Natural Gas Interchangeability*, 115 FERC ¶ 61,325 (2006)); *see also id.* at 4 ("This individual approach recognizes the unique issues associated with each pipeline, including configuration and location, access to processing, gas pressure and temperature, the requirements of the end users, and the needs of interconnecting facilities.").

390. *Id.* at 4 ("To the extent that a natural gas pipeline proposal includes the transportation of hydrogen, the Commission's National Environmental Policy Act review would include the reasonable, foreseeable environmental impacts caused by the project's transportation of hydrogen.").

391. *See* section II.C.1.a, *supra*, discussing how this approach is being actively researched and pursued. *See also* NAT'L RENEWABLE ENERGY LAB'Y, GOLDEN, CO, BLENDING HYDROGEN INTO NATURAL GAS PIPELINE NETWORKS: A REVIEW OF KEY ISSUES, NREL/TP-5600-51995, 21-30 (discussing technological options and associated costs for downstream hydrogen extraction).

392. *See Dominion Energy Transmission, Inc.*, 175 FERC ¶ 61,091 (2021) (rejecting tariff containing different standards for renewable natural gas and other natural gas as unjustified on the record following a technical conference). *See also* Tom DiChristopher, *Hydrogen blending could lead to 'lengthy, contested' proceedings at US FERC*, S&P GLOBAL (Apr. 20, 2022), https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/natural-gas/042022-hydrogen-blending-could-lead-to-lengthy-contested-proceedings-at-us-ferc.

issues.[393] More fundamentally, though, interstate shippers of hydrogen are entitled to common carriage treatment that is distinct from the NGA's regulatory regime.[394]

It may be premature to speculate as to how such an arrangement could practically fit within the existing regulatory regime. After all, no specific plans have been announced and it remains to be seen what arrangements will ultimately be economically, technologically, and logistically feasible. However, there may be a simple solution that could make regulating such arrangements remarkably straightforward. FERC has extensive experience regulating pipeline capacity leases under both the NGA and the ICA.[395] This includes leases to "virtual" pipelines that may not own any separate pipeline assets.[396] FERC could allow natural gas pipelines to lease the required portion of their capacity to separate entities that transports hydrogen. The lessor natural gas pipeline would need permission from FERC to "abandon" that capacity by a lease.[397] The lessee hydro-

393. *See Alliance Pipeline L.P.*, 157 FERC ¶ 61,204 at PP 20-54 (2016) (establishing a hearing under the NGA regarding gas processing issues on a pipeline that transported gas rich in NGLs, which its affiliate had the sole and exclusive right to extract; shipper alleged that this "structure [was] intended to mask the true nature of the bundled service and limit regulatory oversight"), *reh'g denied* 162 FERC ¶ 61,114 at P 10 (2018) ("We decline to clarify that the extraction agreements . . . cannot be explored at hearing due to jurisdictional issues. If the gas processing arrangements affect jurisdictional service, then such matters are within the Commission's purview."). This matter was eventually settled. *Alliance Pipeline L.P.*, 163 FERC ¶ 61,226 (2018), *as amended* 170 FERC ¶ 61,292 (2020).

394. *Cf. Jayhawk Pipeline, L.L.C.*, 151 FERC ¶ 61,020 at P 16 (2015) (finding a pipeline affiliate's proposal to transport crude oil using a portion of its affiliates' capacity (via a lease) was inconsistent with the "the tariff obligations associated with the interstate movements of crude oil . . . [and] common carrier oil pipeline obligations").

395. *See National Fuel Gas Supply Corp.*, 172 FERC ¶ 61,039 at PP 42-44 (2020), *amended* 177 FERC ¶ 62,103 (2021) (describing the Commission's general test for analyzing abandonments by capacity lease under the NGA); *Sabine Pipe Line LLC Bridgeline Holdings, L.P.*, 171 FERC ¶ 61,147 at P 31 (2020) (FERC "looks closely at [lease] proposals that would create dual jurisdiction facilities"). ICA pipelines do not need FERC authorization to lease their capacity. *See Western Refin. Sw., Inc.*, 127 FERC ¶ 61,288 at P 25 (2009). However, FERC still oversees the ratemaking implications of capacity leases in the ICA context. *See Navigator Borger Express LLC*, 175 FERC ¶ 61,133 at P 28 (2021) (approving terms of transportation service agreement offered using leased capacity); *Medallion Pipeline Co.*, 169 FERC ¶ 61,202 at P 20 (2019); *Buckeye Pipe Line Transportation, LLC*, 154 FERC ¶ 61,130 at P 18 (2016); *NORCO Pipe Line Co., LLC*, 152 FERC ¶ 61,170 at P 22 (2015); *Palmetto Prods. Pipe Line LLC*, 151 FERC ¶ 61,090 at PP 32-34 (2015) (analyzing "whether Palmetto can use the leased and underutilized capacity on Plantation to provide firm transportation services under the [transportation service agreement]"); *Guttman Energy, Inc. v. Buckeye Pipe Line Co.*, 147 FERC ¶ 61,088 at PP 27-30 (2014) (dismissing complaint against intrastate pipeline that leased capacity through which its affiliate offered regulated interstate service); *but see* Western Refin. Sw., Inc. v. FERC, 636 F.3d 719, 724 (5th Cir. 2011) (FERC has no jurisdiction over the relationship between lessee and lessor of pipeline capacity under ICA, only jurisdiction over the provision of transportation), *aff'g Western Refining*, 127 FERC ¶ 61,288.

396. Order No. 637, *Regulation of Short-Term Nat. Gas Transp. Serv., & Regul. of Interstate Nat. Gas Transp. Servs.*, FERC Stats. & Regs., ¶ 31,091, at 31,255 (2000) ("The use of released capacity has made possible the development of virtual pipelines. A virtual pipeline can be created when a marketer or other shipper acquires capacity on interconnecting pipelines and can schedule gas supplies across the interconnect, creating in effect a new pipeline between receipt and delivery points that are not physically connected under a single pipeline management."); *see also Marketlink, LLC*, 144 FERC ¶ 61,086 (2013) (FERC approving contract terms for a new "pipeline" which would lease all its capacity from its affiliate and only owned ancillary facilities such as tanks and meters).

397. The Lessee of such capacity "generally needs to be a natural gas company under the NGA." *National Fuel Gas Supply Corp.*, 172 FERC ¶ 61,039 at P 42. However, it need not always be. *See Dome Pipeline*

gen "pipeline" could then operate as a common carrier under its own tariff.[398] This arrangement could provide a simple and proven solution, especially in the short term before new dedicated hydrogen pipelines are economically justified. Given the novel nature of this problem and any potential solution, stakeholders will benefit from regulatory clarification from FERC.

B. *Hydrogen Pipelines Should be Regulated by FERC Under the ICA*

Having ruled out NGA regulation for dedicated hydrogen pipelines, we must next determine which of the Hepburn Act regimes—the ICA or ICCTA—applies. The substantive legal requirements of common carriage are markedly similar in each regime: a mandate to provide open, affordable, and equal transportation. For most issues, the differences between one regime and the other are procedural, bordering on academic.[399] However, FERC is the agency with energy expertise and has a much better developed, understood, and predictable pipeline regulatory regime. It is therefore consistent with sound policy and Congressional intent for FERC to assume jurisdiction over hydrogen pipelines under the ICA.

1. Conventional Hydrogen is a Petrochemical Derivative

Nearly all hydrogen used today is made from fossil resources.[400] Hydrogen is therefore most naturally understood as a petrochemical or petroleum derivative, as contemplated by Congress in 1977. FERC's precedent makes clear this is a reasonable construction. In fact, with hydrogen, this is confirmed by the precedent finding that anhydrous ammonia could be considered a petrochemical specifically because it is made with hydrogen. To the extent ammonia could reasonably be classified as a petroleum derivative, it must be at least as reasonable to classify hydrogen that way.

As described above, Congress intended to entrust FERC with regulating those Hepburn Act pipelines that carry "petroleum by-products, derivatives or petrochemicals."[401] The D.C. Circuit has found that "Congress intended a broader meaning of 'oil' . . . [and] [t]he legislative history, moreover, confirms that 'oil' was not to be given a dictionary meaning."[402] In *Gulf Central*, FERC made clear that classifying ammonia as a petrochemical (or derivative) was at

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Corp., 22 FERC ¶ 61,277, at p. 61,497 (1983) (explaining that the FERC's "primary concern was whether the facility would escape regulation. To the extent that the Commission has jurisdiction over either the owners or the operators, the Commission is assured that it will be able to exercise its regulatory responsibilities. What is essential, then, is that there must be a recipient of regulatory responsibility."); *Transcontinental Gas Pipe Line Co., LLC*, 158 FERC ¶ 61,125 at P 65 (2017) ("Commission jurisdiction over the operator of [leased] facilities is sufficient to ensure the Commission's ability to exercise its regulatory responsibilities.") (citing *Dome Pipeline Corp.*, 22 FERC ¶ 61,277; *El Paso Nat. Gas Co.*, 47 F.P.C. 1527, 1532 (1972)).

398. As discussed next, this tariff should be overseen by FERC under its ICA authority. However, capacity leases could still provide clarity even if the common carrier entity were regulated by the STB.

399. *See generally* Bolgiano & Field, *supra* note 331.

400. The jurisdictional status of non-fossil renewable hydrogen is addressed below in section VI.B.3.

401. DOE Act Conference Reports, *supra* note 139, at 69.

402. CF Indus., Inc. v. FERC, 925 F.2d 476, 478 (D.C. Cir. 1991).

least a permissible interpretation.[403] In examining whether ammonia was a petrochemical, FERC relied on Congress's broad phrasing in the Conference Committee Report and noted that "within the petrochemical industry, anhydrous ammonia is considered a petrochemical because it is derived from petroleum refinery gas or from natural gas."[404] Of course, ammonia is actually made with hydrogen, which is derived derived from those fossil sources, *i.e.* natural gas. FERC ultimately found that there was "sufficient ambiguity" that FERC's "jurisdiction is more appropriately determined by examining the overall purposes of the DOE Act."[405] The D.C. Circuit affirmed this approach.[406]

Hydrogen is still overwhelmingly a petrochemical derived from fossil fuels, as it was in the time of the ammonia cases.[407] And FERC's later orders heavily imply that anhydrous ammonia is a petrochemical and was therefore not subject to FERC's ICA jurisdiction only because it was not used for energy purposes. In *Texaco Petrochemical Pipeline LLC*, FERC stated that *Gulf Central* "*holds* that if a hydrocarbon product shipped by an oil pipeline is not used for energy purposes, the Commission lacks jurisdiction over the transportation of that product."[408] If ammonia were not a petroleum product, this would be dicta, rather than the *holding* of *Gulf Central*. Because anhydrous ammonia *could* be considered a petrochemical, then it necessarily follows that hydrogen—its sole petrochemical component—could also be considered a petrochemical. FERC therefore certainly has the discretion to interpret hydrogen as a "petrochemical or derivative." FERC's ICA jurisdiction over hydrogen pipelines would then turn on whether hydrogen has "current energy uses" or "future undeveloped energy uses."[409] That is certainly the case.

2. Hydrogen Is Primarily Used for Energy Today and it Has Myriad Future Uses

Hydrogen clearly has exciting potential as a renewable fuel, especially for hard-to-abate industries. Further, government policy reflects this understanding that hydrogen is primarily an energy commodity. More importantly though, hydrogen is already used primarily as a component of fuel for its energy characteristics through petroleum refining. In fact, this is the dominant use of hydrogen, and biofuel refining requires hydrogen in even greater quantities. In addition, hydrogen gas is often burned to power refineries. Hydrogen therefore "has cur-

403. *Gulf Cent. Pipeline Co.*, 50 FERC ¶ 61,381, at p. 62,165 (1990).

404. *Id.* at 62,164-65 ("There is also some conflict in the authorities. For example, the McGraw-Hill *Petroleum Products Handbook* lists carbon, hydrogen, and sulphur as petrochemicals.").

405. *Id.* at 62,165.

406. *CF Indus., Inc. v. FERC*, 925 F.2d at 480.

407. *Palmetto Prods. Pipe Line LLC*, 151 FERC ¶ 61,090 at P 30 (2015) (acknowledged that anhydrous ammonia is "derived from natural gas or petroleum refinery gas.").

408. *Texaco Petrochemical Pipeline LLC*, 107 FERC ¶ 61,151 at P 5 (2004) (emphasis added).

409. *See Williams Olefins Feedstock Pipelines, L.L.C.*, 145 FERC ¶ 61,303 at P 16 (2003). Note that in *Williams Olefins* FERC described ethane as a "naturally-occurring hydrocarbon product." *Id.* However, FERC has ICA jurisdiction over many commodities that are not naturally occurring, such as refined products and synthetic crude, which involve changing the molecular structure of the hydrocarbons, as described above in section III.C.2.a, *supra*.

rent energy uses and future undeveloped energy uses" for purposes of the ICA's jurisdictional analysis.[410]

a. Refinery Applications of Hydrogen

Petroleum refineries are the largest consumers of hydrogen nationally.[411] And hydrogen is very important to their operation. Fundamentally, refineries are set up to take heavier, dirtier crude oil and turn it into lighter, cleaner finished products. Refineries use hydrogen to make the products both lighter and cleaner. This happens at the molecular level through hydrocracking and hydrotreating.[412] In both processes, the hydrogen used by the refinery becomes part of the hydrocarbon molecules that are eventually burned as fuel. In addition, refineries often use the excess hydrogen from these operations by directly burning it as fuel. And because biofuels have more impurities and require more upgrading, refining demand for hydrogen should rise along with biofuel consumption.

i. Hydrocracking

Shorter chain hydrocarbons are generally better fuels than very long chain hydrocarbons. They are less viscous, more volatile, boil more readily, more flammable, and burn cleaner. "Cracking" refers to the process of breaking long hydrocarbon molecules into shorter ones.[413] In hydrocracking, hydrogen is added during this process.[414] For instance, during hydrocracking a molecule of decane ($C_{10}H_{22}$) would crack and, in the presence of a molecule of hydrogen (H_2), would become one molecule of butane (C_4H_{10}) and one molecule of hexane (C_4H_{14}).[415] In addition, heavy, sludgy products such as residual fuel (a refining byproduct that resembles asphalt) can be upgraded this way.[416]

Another important measure of a hydrocarbon's quality is the hydrogen-to-carbon (H:C) ratio.[417] As a rule of thumb, finished petroleum fuels have an H:C

410. *Id.* at P 18.

411. H2@SCALE, *supra* note 35, at xii.

412. JAMES H. GARY, GLENN E. HANDWERK, ET AL., PETROLEUM REFINING: TECHNOLOGY AND ECONOMICS (5th ed. 2007) [hereinafter GARY & HANDWERK].

413. *Id.* at 162.

414. *Id.* at 161-180 (*Catalytic Hydrocracking*), 181-193 (*Hydroprocessing and Resid Processing*). *See id.* at 163 (defining hydroprocessing as hydrocracking that focuses on upgrading residual materials); *id.* at 162 ("Although there are hundreds of simultaneous chemical reactions occurring in hydrocracking, it is the general opinion that the mechanism of hydrocracking is that of catalytic cracking with *hydrogenation* superimposed. Catalytic cracking is the scission of a carbon-carbon single bond, and *hydrogenation is the addition of hydrogen to a carbon-carbon double bond*.") (emphasis added).

415. *Id.* at 200.

416. *Id.* at 162 (describing that the upgrading of heavier oils via hydrocracking requires different equipment and is referred to as *hydroprocessing*). *See also id.* at 181-193.

417. *See, e.g.*, A. G. Olugbenga & E. N. Arua, *Modification of Outlet Stream of the Atmospheric Distillation to Improve Products from Heavy Crude Oil Using Aspen Simulations*, 14 J. SCI., TECH., MATHEMATICS & EDUC. 70 (2018) ("Hydrogen to carbon ratios affects the physical properties of crude oil. As the hydrogen to carbon ratio decreases, the gravity and boiling point of the hydrocarbon compounds increases. The higher the hydrogen to carbon ratio of the feedstock, the higher its value to the refinery because less hydrogen is required.") (citations omitted). The H/C ratio of a fuel also corresponds to what share of its emissions are carbon dioxide (CO_2) versus water (H_2O).

ratio of about two-to-one.[418] Meaning that for every carbon atom in the fuel there should be two of hydrogen on average. Crude oil has an H:C ratio of about 1.6, which may be lower in poor quality feedstocks such as tar sand bitumen.[419] Hydrocracking and other processes that increase the hydrogen content of (hydrocarbon) fuels necessarily increase the products' H:C ratio.[420] The hydrogen added to fuel via hydrocracking therefore improves the products' energy attributes.

In overly simple terms, hydrogen can be thought of as a leavening agent in the production of gasoline, jet fuel, and diesel. It allows refiners to produce lighter, more valuable products from heavier, less valuable inputs. Demand for hydrogen to upgrade products is driven by the quality of a refinery's raw materials and the products needed to be produced.[421] According to at least one estimate, the majority of hydrogen used by refineries is used for upgrading applications.[422] All the hydrogen that a refinery uses in hydrocracking is intended to become part of the fuel it produces.[423] In this way, hydrogen used by a refinery to upgrade products is not fundamentally different than any of its other raw petroleum materials, such as crude oil. Its purpose is to become a part of the fuels that power our cars, trucks, and jets.

ii. Hydrotreating

The other major use for hydrogen in refineries is to remove impurities through "hydrotreating."[424] Like hydrocracking, the removal of "heteroatom," impurities such as sulfur, occurs at the molecular level.[425] There is a bit of a misconception that this is the only use for hydrogen at a refinery.[426] As noted above, more hydrogen is used in upgrading fuels than treating them. Further, the chemical reactions all occur simultaneously so the difference between hydrotreating and hydrocracking often boils down to purpose.[427] Therefore, even when a refinery uses hydrogen to remove impurities, a good deal of that hydrogen also becomes part of the fuels that are eventually consumed for energy.

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418. James G. Speight, *Feedstock Composition*, in HANDBOOK OF PETROLEUM REFINING 102 (2016), https://www.routledgehandbooks.com/doi/10.1201/9781315374079-5.

419. *Id.* at 102-03.

420. HAROLD H. KUNG, NAT'L ACAD. OF SCIS., *Increasing Efficiencies for Hydrocarbon Activation*, CARBON MANAGEMENT: IMPLICATIONS FOR R&D IN THE CHEMICAL SCIENCES AND TECHNOLOGY: A WORKSHOP REPORT TO THE CHEMICAL SCIENCES ROUNDTABLE 161 (2001) ("The hydrogen-to-carbon ratio in most petrochemicals is higher than in crude oil. Therefore, hydrogen must be added in their production.").

421. H2@SCALE, *supra* note 35, at 5-10.

422. *Id.* at 5, fig. 2.1 (citing Elgowainy et al., *Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries*, 48 ENV'T SCI. TECH. 7614, 7619 fig. 6 (2014) (fluid catalytic cracking unit (FCCU) and hydrotreater (HDT) uses combined with Hydrocracking applications account for more than 50% of average refinery hydrogen demand)).

423. *See* GARY & HANDWERK, *supra* note 412, at 163 & fig. 7.1.

424. *Id.* at 195-205 (*Hydrotreating*).

425. *Id.* at 195.

426. *Hydrogen Explained: Use of Hydrogen*, U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php ("U.S. petroleum refineries use hydrogen to lower the sulfur content of fuels."). The author of this article was also guilty of this misconception until a client very kindly educated him. *See* Bolgiano & Field, *supra* note 331, at 2 (saying hydrogen was "used by refiners to lower the sulfur content of fuels.").

427. GARY & HANDWERK, *supra* note 412, at 195 ("The terms *hydrotreating*, *hydroprocessing*, *hydrocracking*, and *hydrodesulfurization* are used rather loosely in the industry because, in the hydrodesulfurization and hydrocracking processes, cracking and desulfurization occur simultaneously, and it is relative as to which predominates.").

In addition, many hydrotreating reactions also increase the hydrogen content of the products. For instance, in order to desulphurize thiopene (C_4H_4S), hydrogen (H_2) would be added, along with heat, pressure, and a catalyst. The thiopene molecule would be cracked and would combine with four of the hydrogen molecules. The result would be one molecule of butane (C_4H_{10}) and one molecule of hydrogen sulfide (H_2S), which would be removed.[428] Because the butane molecule has more hydrogen atoms than the thiopene, much of the hydrogen employed in this process becomes part of the fuel that will ultimately be combusted for energy by end-consumers. Therefore, even in hydrotreating, where the primary intent is to remove an element from the fuels, much of the hydrogen used by the refinery ultimately makes its way into the fuels that power internal combustion engines everywhere.

iii. Renewable Fuels

As with conventional oil refining, the hydrogen required to refine renewable fuels becomes an integral part of the fuel and is combusted by its consumers. In fact, refining biomass into renewable fuels requires more hydrogen than refining petroleum.[429] Hydrogenated vegetable oil (HVO) is actually the starting point for developing a host of biofuels, including sustainable aviation fuel and renewable diesel.[430] Renewable hydrocarbons made from biomass must mimic their fossil counterparts, including their two-to-one H:C ratio.[431] In addition to carbon and hydrogen, biomass also contains significant amounts of oxygen. On average, for each atom of carbon, a biomass molecule contains 1.44 atoms of hydrogen and also 0.66 molecules of oxygen.[432] Therefore, hydrogen is needed

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428. *Id.* at 199.

429. U.S. DEP'T OF ENERGY, OFFICE OF ENERGY EFFICIENCY & RENEWABLE ENERGY, SUSTAINABLE AVIATION FUEL: REVIEW OF TECHNICAL PATHWAYS 48 (2020), https://www.energy.gov/sites/prod/files/2020/09/f78/beto-sust-aviation-fuel-sep-2020.pdf ("Hydrogen demand is high for all biofuels and unusually high for [sustainable aviation fuel]"); SUSAN VAN DYKE ET AL., 'DROP-IN' BIOFUELS: THE KEY ROLE THAT CO-PROCESSING WILL PLAY IN ITS PRODUCTION 1 (2019), IEA BIOENERGY, https://www.ieabioenergy.com/wp-content/uploads/2019/09/Task-39-Drop-in-Biofuels-Full-Report-January-2019.pdf ("The important role of hydrogen in upgrading biological feedstocks was emphasised as a key challenge for the future development of drop-in biofuels. This is even more pertinent now, particularly finding cheap and renewable sources of hydrogen.").

430. J.H. Van Gerpen & B.B. He, *Biodiesel and renewable diesel production methods*, in ADVANCES IN BIOREFINERIES, BIOMASS AND WASTE SUPPLY CHAIN EXPLOITATION 427 (Keith Waldron, ed., et al., 2014) ("The basic process to produce renewable diesel starts with hydrogenation. . . .").

431. SUSAN VAN DYK ET AL, POTENTIAL SYNERGIES OF DROP-IN BIOFUEL PRODUCTION WITH FURTHER CO-PROCESSING AT OIL REFINERIES, BIOFUELS, BIOPRODUCTS BIOREFINING 760, 762 fig.1 (2019); https://www.nrel.gov/docs/fy19osti/73115.pdf; *see also* C.W. Forsberg et al., *Replacing liquid fossil fuels and hydrocarbon chemical feedstocks with liquid biofuels from large-scale nuclear biorefineries*, 298 APPLIED ENERGY 117225, 4 (2021) ("The more hydrogen that is added, the more hydrocarbon fuel that is produced.").

432. Forsberg et al., *supra* note 431; *see also* Xianhui Zhao et al., *Review of Heterogeneous Catalysts for Catalytically Upgrading Vegetable Oils into Hydrocarbon Biofuels*, 3 CATALYSTS 83 (2017), https://www.mdpi.com/2073-4344/7/3/83/htm ("The H/C molar ratio of petroleum product is 2.0, which is in the range of the H/C molar ratio of vegetable oils (between 1.64 and 2.37). However, the H/C molar ratio of bio-oil was ranging from 0.92 to 1.53. The oxygen content of vegetable oils was between 10.5% and 14.5%, which was much lower than that of bio-oil (28%–40%.)").

both to upgrade biomass feedstocks through hydrogenation,[433] and to remove oxygen and other impurities.[434] Therefore, hydrogen will continue to be an energy commodity used for refining well after the transition from fossil fuels.

b. Other Thermal Energy Applications

Hydrogen by itself also "has a thermal heat content that has the capability of being burned and used for fuel and energy purposes," which FERC found sufficient to establish ICA jurisdiction over ethane.[435] As discussed above, renewable hydrogen has future potential uses in decarbonizing heat-intensive industry and potentially displacing or replacing methane in our gas distribution networks. While not quite as powerful as methane, hydrogen is still a potent fuel and burns very clean: producing only steam and some nitrogen oxides. Moreover, conventional hydrogen is already burned in refineries as fuel. The excess hydrogen that is not consumed in upgrading and treating crude oil is recovered and mixed into the refinery fuel gas stream, along with methane and other light hydrocarbons.[436] The percentage of hydrogen in a refinery's fuel gas stream ranges from 10 to 60 percent.[437]

c. Chemical Energy

Hydrogen can also serve as a fuel without combustion.[438] A hydrogen fuel cell generates electric power by harnessing the power of the chemical reaction of

433. J.H. Van Gerpen & B.B. He, *supra* note 430, at 441-475 ("The basic process to produce renewable diesel starts with hydrogenation which saturates the double bonds and removes the oxygen, either as H2O or CO2 depending on the availability of hydrogen, from the fatty acid chains of the triacylglyceride. Hydrogenation and decarboxylation are two of the basic reactions that occur during the production of renewable diesel"); HANDBOOK OF BIOFUELS PRODUCTION: PROCESSES AND TECHNOLOGIES 381 (Rafael Luque, ed., 2d ed. 2016) ("a great number of the approaches reported in this chapter need a high amount of hydrogen in order to remove the oxygen and yield high-energy-density biofuels.") *See also id.* at 19.2.2 ("Two-stage HT of bio-oil has been the accepted practice for bio-oil upgrading for the last 25 years") (citing Elliott D.C., *Historical developments in hydroprocessing bio-oils*, ENERGY & FUELS. 2007, 21:1792–1815 web publication, May 2, 2007).

434. ALAIN A. VERTES ET AL., GREEN ENERGY TO SUSTAINABILITY: STRATEGIES FOR GLOBAL INDUSTRIES, at 5.2.1 (Driving Force of Growing Biojet Fuel Opportunities) ("[T]he oxygen element in biomass is much more than that of crude oil, which requires more energy input to effectively remove excess oxygen and produce hydrocarbons consisting of only carbon and hydrogen atoms. This is one of the reasons why hydrogen hydrotreating is needed in nearly all biojet fuel conversion pathways, and the cost and availability of these industrial processes are considered a risk in the research and development of biojet fuel.").

435. *Williams Olefins Feedstock Pipelines, L.L.C.*, 145 FERC ¶ 61,303 at P 17 (2013).

436. *See, e.g.*, 40 C.F.R. § 63.641 ("[Fuel gas] can contain a mixture of methane, light hydrocarbons, hydrogen and other miscellaneous species.").

437. ROBERT G. KUNZ, ENVIRONMENTAL CALCULATIONS: A MULTIMEDIA APPROACH 285 (app. L) (2009) ("Hydrogen in RFG may vary from 10% up to about 60%, if not separated for use in hydrotreating operations") (citations omitted). *See also* Elgowainy et al., *supra* note 422, at 7614-15 ("In 2012, 37% of the direct processing energy use at U.S. refineries was refinery fuel gas (FG), 25% NG, 13% captive (i.e., produced internally) and merchant (i.e., purchased) hydrogen, 14% refinery catalytic coke, 6% purchased steam, 4% purchased electricity, and 1% other fuels.").

438. Hydrogen would also be the fuel for nuclear fusion, which fuses hydrogen atoms together in the same reaction that powers our sun. IRENA CHATZIS & MATTEO BARBARINO, WHAT IS FUSION AND WHY IS IT SO DIFFICULT TO ACHIEVE? 4, INT'L ATOMIC ENERGY AGENCY (2021), https://www.iaea.org/fusion-energy/what-is-fusion-and-why-is-it-so-difficult-to-achieve. While exciting developments have occurred recently, this technology remains speculative and, even if proven, the demand for hydrogen would likely be small given that

pure hydrogen with oxygen found in ambient air. This reaction generates water, electricity, and heat (which can also be utilized). This form of chemical energy is seen as the best hope to convert numerous energy-intense industries where batteries cannot—literally—stack up against diesel or other fuels. Because hydrogen is so light, a fuel cell could power electric motors on planes, ships, and heavy machinery where batteries would weigh down the apparatus to the point of frustration.

FERC's pipeline regime was developed against the backdrop of conventional fossil fuels. It is therefore unclear how important it is that energy be generated by a commodity's combustion. As described above, combustion for heat is clearly sufficient to qualify as "fuel" or "energy" for purposes of FERC's analysis. Whether chemical energy such as from a fuel cell would be a sufficient condition to qualify as "fuel" is unclear. Fortunately, this distinction is academic because hydrogen does have thermal energy potential and continues to be burned for energy, either in pure form or as a component of other finished hydrocarbon products.

d. Hydrogen Is an Energy Commodity as a Matter of Public Policy

Public policy shows hydrogen to be an energy commodity that should be subject to FERC's regulation. In finding that ethanol was subject to its ICA jurisdiction, FERC considered the government's role in promoting the renewable fuel and the fact that "the Energy Information Administration has recognized that ethanol has its own energy content and has classified it as a fuel source."[439] While it is not clear how important this factor was to FERC's analysis, hydrogen certainly meets this criterion. The EIA describes hydrogen as an "energy carrier" and a "fuel."[440] Further, the Department of Energy's Alternative Fuels Data Center calls hydrogen "a zero tailpipe emissions alternative fuel" and has compiled significant data on the production, vehicles, and fueling infrastructure.[441] The Department of Energy has a "Hydrogen Program Plan."[442] Lowering the cost of renewable hydrogen was the first of the Department's "Earthshots."[443] In 2020, FERC classified hydrogen as a "useful thermal energy output," encouraging its production.[444] And finally, the recent Infrastructure Act confirms that hydrogen is an energy commodity. The bill instructs the Secretary of Energy to

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fusion reactors have the revolutionary potential to create tremendous energy from insignificant amounts of fuel. Thomas Overton, *Fusion Energy Is Coming, and Maybe Sooner Than You Think*, POWER MAG (2020), https://www.powermag.com/fusion-energy-is-coming-and-maybe-sooner-than-you-think/.

439. *Palmetto Prods. Pipe Line LLC*, 151 FERC ¶ 61,090 at P 31 (2015).

440. U.S. ENERGY INFO. ADMIN., HYDROGEN EXPLAINED, https://www.eia.gov/energyexplained/hydrogen/ (last updated Jan. 20, 2022) ("Hydrogen has the highest energy content of any common fuel by weight (about three times more than gasoline), but it has the lowest energy content by volume (about four times less than gasoline).").

441. U.S. DEP'T OF ENERGY, ALT. FUELS DATA CTR., HYDROGEN, https://afdc.energy.gov/fuels/hydrogen.html.

442. U.S. DEP'T OF ENERGY, DEPARTMENT OF ENERGY HYDROGEN PROGRAM PLAN (2021).

443. U.S. DEP'T OF ENERGY, OFF. OF ENERGY EFFICIENCY AND RENEWABLE ENERGY, HYDROGEN SHOT, https://www.energy.gov/eere/fuelcells/hydrogen-shot.

444. Order No. 874, *Fuel Cell Thermal Energy Output*, 173 FERC ¶ 61,226 at P 15 (2021).

take numerous steps to advance hydrogen, including the development of a "national strategy and roadmap to facilitate widescale production, processing, delivery, storage, and use of clean hydrogen."[445] Perhaps most importantly, Congress instructed the Secretary of Energy, not Transportation, to promote hydrogen "transmission by pipeline."[446] All of these factors lean in favor of FERC regulating hydrogen pipelines, rather than the STB.

e. Other, Non-Energy Uses Do Not Compromise FERC's Jurisdiction

The fact that hydrogen has energy potential should end this part of the analysis. It does not matter that hydrogen still has other non-energy applications, even if they are significant. FERC made clear in *Williams Olefins*, that so long as a petrochemical has potential energy uses, FERC has jurisdiction over pipelines transporting it.[447] Hydrogen will continue to serve an irreplaceable non-energy role in a host of important industries after the transition from fossil fuels. But none of the myriad non-energy applications of hydrogen would undercut FERC's prerogative to regulate energy petrochemicals and their non-petrochemical substitutes.

3. Renewable Hydrogen Is Not a Petrochemical but Competes with Other FERC-Regulated Commodities and Impacts Energy Markets

While conventional hydrogen is best understood as a petrochemical or derivative, renewable hydrogen derived from water or biomass is not. FERC can still assert jurisdiction over such hydrogen, however. In *Palmetto*, FERC set forth the following test for establishing jurisdiction over ethanol as "oil":

> (1) whether the commodity is a fuel source in that it has heating value and is used for energy-related purposes; (2) whether the cost of transportation will have an impact on energy markets; and (3) whether the commodity will compete with oil or other refined products for capacity in the pipeline. [448]

Renewable hydrogen meets this test.

First, as described above, hydrogen indisputably has heating value and it is currently used for energy-related purposes. It is primarily used for energy purposes today, and interest in renewable hydrogen is also primarily as a fuel. Second, the cost for transporting hydrogen would impact energy markets. In *Palmetto*, FERC found this to be the case because "ethanol accounts for ten percent of the total volume of motor gasoline" and "[a]s ethanol consumption increases, more pipeline capacity will be required causing the cost to transport other liquids to change."[449] As described above, hydrogen is an integral part of making conventional and renewable fuels, and it is becoming an important fuel in its own

445. Infrastructure Act § 40314, 135 Stat. at 1,009 (codified at 42 U.S.C. § 16161b(1)).

446. *Id.* § 40313, 135 Stat. at 1,007 (codified at 42 U.S.C. § 16154(e)(6)(A)).

447. *Williams Olefins Feedstock Pipelines, L.L.C.*, 145 FERC ¶ 61,303 at P 16 (2013) ("the Commission's jurisdiction cannot be based on an applicant's assertion of a product's end use in the case of a product that has potential fuel and energy uses. Rather, the Commission considers both existing and potential energy uses.").

448. *Palmetto Prods. Pipe Line LLC*, 151 FERC ¶ 61,090 at P 30 (2015).

449. *Id.* at P 31.

right. Further, natural gas pipelines are considering blends of hydrogen in excess of 10 ten percent. A net-zero economy will need to move tremendous amounts of green hydrogen from renewable electricity sources to airports, factories, mines, marine ports, biofuel refineries, power plants, utilities, and unforeseen future consumers. If this cannot be done on open, equal, and affordable terms, it will impact the energy markets and risk stifling the transition to renewables.

Finally, renewable hydrogen would compete with "oil" for pipeline space because, as discussed above, conventional hydrogen should be considered "oil" for purposes of the ICA. If it is not considered oil for purposes of the ICA, the analysis is more complicated. Hydrogen requires different pipelines than oil and finished products, so does not directly compete with those products for pipeline space. However, it can—and likely will—compete with natural gas for pipeline space, since gas pipelines may carry a mix of hydrogen and natural gas.[450] In *Gulf Central*, FERC articulated that ammonia should not be regulated by FERC because it did not "compete with oil *or gas* for capacity in the same pipeline facilities."[451] Beyond physical pipeline space, hydrogen competes with fossil fuels in many ways both currently and potentially. Right now, hydrogen allows refineries to produce greater volumes of products from lower quality crude oils. In that way, hydrogen indirectly competes against higher quality crude oils because cheaper hydrogen would make lower quality crude more attractive. In the future, the use of hydrogen to power fuel cells is also seen as a competitor to displace diesel, jet, and bunker fuel. And of course, when burned, hydrogen is in direct competition with natural gas.[452]

4. FERC Is Better Suited to Regulate Hydrogen Pipelines than the STB

Whether FERC or the STB should regulate pipelines carrying a commodity boils down, in large part, to Congress's decision to have FERC regulate the energy markets—a decision that is based on sound policy. FERC's expertise and experience make it much better equipped to regulate hydrogen pipelines than the STB. Commissioner Glick confirmed this in his letter to Senator Heinrich, saying that FERC's "experience with issues relating to the siting of linear infrastructure, and with regulating the rates, terms, and conditions of transportation service on interstate natural gas pipelines as described above, may be analogous to the expertise needed for the regulation of hydrogen pipelines."[453] And more recently, Congress instructed the Secretary of Energy to promote hydrogen "transmission by pipeline."[454] Asserting jurisdiction over hydrogen pipelines under the ICA could be one of FERC's first step in furthering this statutory objective.

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450. HYDROGEN COUNCIL & MCKINSEY, *supra* note 24, at 41; H2@SCALE, *supra* note 25, 43-44; MELAINA ET AL., *supra* note 54, at 21. *See also* discussion in section II.C.1.a.

451. *Gulf Cent. Pipeline Co.*, 50 FERC ¶ 61,381, at p. 62,166 (1990).

452. *See id.* at 62,165-66 (recounting that Congress chose FERC to regulate oil pipelines because oil competed more with natural gas, also regulated by FERC than it did with coal, regulated by the ICC (now STB)).

453. Letter from Richard Glick, *supra* note 371, at 3.

454. Infrastructure Act § 40313, 135 Stat. at 1,007 (codified at 42 U.S.C. § 16154(e)(6)(A)).

To provide one specific example, FERC's experience overseeing the abandonment of gas pipelines and their conversion to ICA uses could directly facilitate hydrogen pipeline development. As described above, there is promising potential to repurpose natural gas pipelines to carry hydrogen.[455] Converting a pipeline from (or to) carrying natural gas requires FERC approval.[456] Fortunately, FERC already has experience overseeing conversion of pipelines from one regulatory regime to another. In fact, it's been doing that since day one.[457] More recently, FERC facilitated the "Pony Express Pipeline Conversion Project" by approving the abandonment of a natural gas pipeline,[458] as well as proving advance approval of the pipeline's contract and rate structure for new crude oil shippers.[459] FERC also has experience with converting ICA pipelines to carry natural gas.[460] In addition, a natural gas pipeline could also partially convert to carrying hydrogen, through an abandonment by lease that would need FERC approval under the NGA. Having one agency oversee these conversions would provide the sort of centralized coordination that goes to the heart of the DOE Act's purpose.

C. Hydrogen Is Not "Artificial Gas" for Purposes of the Hepburn Act, or Otherwise Exempt from Regulation

Finally, hydrogen is not otherwise exempted from regulation. As discussed above, the STB precedent has made clear that the Hepburn Act's exemption of natural and artificial gas should be read narrowly.[461] One might attempt to argue that hydrogen could have been included in the category of "artificial gases" exempted in 1906. After all, at the time the Hepburn Act was enacted, the typical artificial gas was often composed of significant amounts of hydrogen, sometimes as much as half.[462] But this argument is ultimately unavailing. At that time artificial gas had a particular meaning and purpose, as the legislative history makes clear. Even though artificial gas contained significant amounts of hydrogen, pure hydrogen was not used as a fuel gas at that time. Nor could it have been: at that time cities and homes relied on artificial gas for lighting,[463] where hydrogen would be useless.[464] Further, at the time of the Hepburn Act, hydrogen was un-

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455. CRS REPORT, *supra* note 51, at 7-8; HYDROGEN COUNCIL & MCKINSEY, *supra* note 24, at 20.

456. 15 U.S.C. § 717f(b).

457. *El Paso Nat. Gas Co.*, 1 FERC ¶ 61,108 (1977) (approving abandonment of natural gas pipeline that would be converted to carry crude oil).

458. *Tallgrass Interstate Gas Transmission, LLC*, 144 FERC ¶ 61,197 at P 1 (2013); *Tallgrass Interstate Gas Transmission, LLC*, 148 FERC ¶ 61,003 (2014).

459. *Kinder Morgan Pony Express Pipeline, LLC*, 141 FERC ¶ 61,249 at P 1 (2012).

460. *Missouri Interstate Gas, LLC*, 142 FERC ¶ 61,195 at PP 59-64 (2013) (application of *Longhorn* rule to determine whether new ratepayers may be charged acquisition premium when converting from one regulated service to another). *See Longhorn Partners Pipeline*, 73 FERC ¶ 61,355 (1995)).

461. *CF Indus., Inc. v. Koch Pipeline Co., L.P.*, 4 S.T.B. 637, 640 n.11 (2000) (abrogating *Cortez Pipeline Co.*, 46 Fed. Reg. 18805 (I.C.C. Mar. 26, 1981)).

462. CRS REPORT, *supra* note 51, at 6; CASTANEDA, *supra* note 116, at 4.

463. *See* CASTANEDA, *supra* note 116, at 6-36, 59-62; CRS REPORT, *supra* note 51, at 6-7.

464. Hydrogen burns clear and produces virtually no light. For instance, Japan—which is perhaps the strongest government supporter of hydrogen—powered the 2020 Olympic torch using the fuel. But they needed to add sodium carbonate so spectators could see the flame. *See* Peter Lyon, *Tokyo's Olympic Flame Boasts*

derstood to be its own distinct resource with aeronautical applications—where its combustibility was a distinct disadvantage.[465] The canon of reading exemptions narrowly cautions against reading the Hepburn Act as exempting hydrogen, especially when Congress opted for a comprehensive scope of jurisdiction. Congress chose to regulate everything except water and natural or artificial gas when it passed the Hepburn Act, and it is untenable to argue hydrogen was meant to be encompassed in that exemption. Hydrogen pipelines must therefore be subject to some form of economic regulation.

VII. CONCLUSION

The pipeline regulatory framework already covers all potential uses and sources of hydrogen. When mixed with methane, that blended gas is covered by the NGA. When transported by itself, hydrogen is covered by the Hepburn Act. The question of which manifestation of the Hepburn Act (ICCTA or the ICA) applies, depends on which agency (the STB or FERC) is the better regulator. Agency precedent and Congressional purpose all point to the conclusion that FERC can and should regulate hydrogen pipelines. Hydrogen has a unique diversity of sources and applications: fossil and renewable, energy and chemical. These sources and applications that inform the jurisdictional analysis are changing fast. The trend towards renewable sources of hydrogen and towards a more central role for it in the energy sector makes FERC's regulation of hydrogen pipelines even more important. FERC's ICA regime would provide regulatory certainty needed to support investment in a hydrogen pipeline network while keeping the infrastructure open and accessible to foster hydrogen's widespread adoption and protect consumer interests.

The transition from fossil fuels is an unprecedented undertaking. It will require massive financial investments and large, complex physical transformations completed as quickly as possible. Wherever we can, we should employ existing infrastructure, assets, and institutions. Hydrogen pipelines will undoubtedly play a role in decarbonizing numerous sectors of the economy. We are very fortunate to have this regulatory framework already in place. America's comprehensive pipeline regulatory framework provides us the tools to govern the transportation of hydrogen as well as other renewable commodities. We should use this authority now to start building the open, affordable, and fair renewable pipeline network the energy transition will soon urgently need.

First Ever Hydrogen-Powered Cauldron, FORBES (Jul. 28, 2021, 11:28 AM), https://www.forbes.com/sites/peterlyon/2021/07/28/tokyos-olympic-flame-boasts-first-ever-hydrogen-powered-cauldron/?sh=35398a913da5.

465. *See* U.S. DEPT. OF AG., REPORT OF THE CHIEF OF THE WEATHER BUREAU, H.R. DOC. NO. 59-814, at XIII (2d Sess. 1906) (discussing an "electrolyzer for the manufacture of the hydrogen gas employed in the kite balloon and the small rubber balloons.").

TOO MUCH IS NEVER ENOUGH: CONSTRUCTING ELECTRICITY CAPACITY MARKET DEMAND

*Todd Aagaard** *& Andrew N. Kleit***

Synopsis: Some regions of the United States have created institutions known as capacity markets in an effort to use competitive market forces to ensure adequate electricity supply at lowest cost. But capacity markets are driven more by political and bureaucratic judgments than by competition. The manner in which the capacity market is designed to determine demand exemplifies this observation. As there is no natural demand for capacity, Regional Transmission organizations (RTOs) administratively create demand in capacity markets. RTOs derive capacity demand from three components: the capacity requirement based on forecasted peak demand plus an additional margin, the net cost of new entry based on the cost of new facilities entering the market, and the shape of the demand curve. The processes that RTOs use to generate each of these components lack theoretical or analytical justification and tend to produce biased results. As a result, electricity customers are paying billions of dollars for excess capacity that is unnecessary to maintain adequate grid reliability. Capacity markets should address these shortcomings so that demand reflects the actual value of capacity.

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I. INTRODUCTION

The United States economy runs on enormous quantities of energy, much of which is used in the form of electricity that is generated, transmitted, and distributed through the electricity grid. More than eight thousand power plants produce almost four trillion kilowatt hours of electricity annually, which five million miles of transmission and distribution lines deliver to 150 million electricity customers.[1] The modern electricity grid is so complex that it seems almost impossible that it is able to function as well and as reliably as it does. American households and businesses take for granted that the grid will provide power on demand at all times and in virtually any circumstances short of a catastrophic natural disaster.

In fact, however, the electricity sector and its state and federal regulators invest considerable effort and substantial resources via a variety of policies to ensure that the economy has reliable access to electricity. In some areas of the country that transact electricity through competitive markets, the system operators, known as regional transmission organizations (RTOs), have created capacity markets to support the reliability of the electricity grid. The reliability of the grid encompasses two distinct aspects, resource adequacy and operating reliability.[2] Adequacy, associated with long-term reliability, refers to the electricity system's ability to provide sufficient supply to electricity consumers, even during conditions of peak demand. Operating reliability, associated with short-term reliability, is the system's ability to withstand sudden disturbances such as unexpected outages at large generation plants.[3] When referring to reliability, this article focuses on resource adequacy, as concerns about adequacy create the impetus for capacity markets.

RTOs created capacity markets to ensure that the grid will have sufficient generation capacity to satisfy peak demand in the future, so that the grid continuously provides a reliable supply of electric power. Capacity markets do this by creating an additional revenue stream for resources that, in return for receiving payments, incur an obligation to be available to provide power on demand. This

1. *See* ENERGY INFORMATION ADMINISTRATION, ELECTRIC POWER ANNUAL (2018); ENERGY INFORMATION ADMINISTRATION, FREQUENTLY ASKED QUESTIONS (2019); Jennifer Weeks, *U.S. Electrical Grid Undergoes Massive Transition to Connect to Renewables*, SCI. AM. (Apr. 28, 2010).

2. *See* NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, 2018 LONG-TERM RELIABILITY ASSESSMENT 5 (2018).

3. *See id*.

additional revenue stream of capacity payments is supposed to encourage construction of new generation and to allow some existing generation to remain in operation, to the extent necessary to achieve adequate reliability.

A capacity market operates as an auction that matches demand and supply to provide the desired level of capacity at the lowest price. Sellers in the market are generators and other resources that supply electric power.[4] Buyers in the market are load-serving entities that sell electricity to end users in retail electricity markets. Each buyer's purchase of capacity in the market increases the overall reliability of the grid. Reliability benefits every user of electricity from the grid. Grid reliability is thus a public good, as the benefit of a capacity purchase accrues to all those who rely on the grid.

What is known as the 'missing money' theory posits that the market cannot rely on private preferences of load-serving entities to purchase the amount of capacity sufficient to attain the optimal level of grid reliability.[5] Accordingly, an RTO that operates a capacity market creates demand in the market administratively so that the market will provide the desired level of capacity, sufficient to meet overall system-wide peak demand for electricity.[6] The RTO then obligates each load-serving entity to buy its quota of capacity in the market, an amount that reflects its share of the system's overall peak electricity demand.

Originally, in what we term *first generation capacity markets*, capacity markets set demand as a fixed quantity deemed sufficient to meet long-term resource adequacy. This created a vertical demand curve, with demand for the capacity product at the same quantity regardless of price. But a vertical demand curve (along with other pathologies) severely impaired the early capacity markets, leading to reforms in the early 2000s that created *second generation capacity markets* with downward-sloping demand curves in which the quantity demanded increases as price decreases. The downward slope comports with the general economic principle of diminishing returns, which posits that the marginal value of a product decreases as the quantity increases.[7]

In organically arising markets, a demand curve should represent the marginal value of the product demanded—that is, a buyer in the market should be

4. In addition to traditional generation such as gas-fired power plants, other contributors to resource adequacy such as demand response, energy efficiency, and transmission can sell into capacity markets. *See* PJM INTERCONNECTION, L.L.C., PJM MANUAL 18: PJM CAPACITY MARKET 15 (Revision 49, Aug. 1, 2021). The premise of this inclusion is that reducing power demand through demand response and enhanced efficiency and adding transmission capability can contribute to resource adequacy just as traditional power generation can.

5. Separately from the resource adequacy policies of RTO capacity markets, many states apply their own resource adequacy policies to regulated utilities, often through what is known as Integrated Resource Planning. *See* Charles B. Howland, *Brightfields: Sustainable Opportunities for Renewable Energy Projects on Environmentally Impaired Lands*, NAT. RESOURCES & ENV'T, Fall 2014, at 41, 43.

6. In addition, the RTOs also operate zonal submarkets for capacity so that areas impacted by transmission congestion will have adequate supply to meet peak demand. *See*, e.g., NextEra Energy Res., LLC v. FERC, 898 F.3d 14, 20 (D.C. Cir. 2018) (noting ISO New England's use of zonal demand curves in its capacity market).

7. *See* N. GREGORY MANKIW, PRINCIPLES OF MICROECONOMICS 443 (7th ed. 2012).

willing to pay as much for the product as the product is worth to the buyer.[8] Application of this framework to capacity markets poses a challenge, because system operators lack reliable information about the marginal value of capacity to electricity consumers.[9]

This leaves capacity market design in a quandary. Markets are formed by the interaction of supply and demand. Here, natural demand for capacity is inadequate, consistent with the missing money theory, because system capacity is a public good.[10] Capacity market design accordingly must create demand administratively. Theoretically demand should reflect marginal value—that is, the incremental benefit to consumers of an additional unit of capacity. But RTOs do not know the marginal value of capacity. So RTOs creating capacity markets have tended to design demand curves based on three factors: a capacity requirement that reflects forecasts of future demand, the cost of new entry, and a slope (which is a function of the desired price elasticity).[11]

The decisions to use these factors to determine capacity market demand were pragmatic judgments unmoored to economic theory.[12] Moreover, each of these factors entails a series of administrative judgments that are subject to dis-

8. *See* Todd S. Aagaard & Andrew N. Kleit, *The Complexity Dilemma in Policy Market Design*, 30 DUKE ENVTL. L. & POL'Y F. 1, 87 (2019).

9. The value of capacity is sometimes measured as the value of lost load, representing the cost of an electricity outage. The value of lost load, however, is notoriously difficult to determine. *See* Andreas Bublitz, *A Survey on Electricity Market Design: Insights from Theory and Real-World Implementations of Capacity Remuneration Mechanisms*, 80 ENERGY ECON. 1059, 1060 (2019). The value of lost load depends on various factors such as the length of the relevant outage, how much advance notice consumers receive of the outage, what sector (residential, commercial, industrial) the outage affects, the characteristics and demographics of the affected consumers, as well as the specific location studied. *See* Abhishek Shivakumar et al., *Valuing Blackouts and Lost Leisure: Estimating Electricity Interruption Costs for Households Across the European Union*, 34 ENERGY RESEARCH & SOCIAL SCI. 39, 40 (2017).

10. *See* MANKIW, *supra* note 7, at 216 (defining a public good as something that is non-excludable, people cannot be prevented from using it, and non-rivalrous ,one person's use does not diminish another person's ability to use). National defense and basic research are examples of public goods. *See id*. at 219-20. Markets tend to undersupply public goods because people know they can free ride—that is, obtain the benefit of a public good without paying for it. *See id*. at 218.

11. *See, e.g.*, MANASA KOTHA, CAPACITY ZONES FORMATION AND DEMAND CURVES 24 (ISO New England 2019); JOHANNES PFEIFENBERGER ET AL., REVIEW OF PJM'S RELIABILITY PRICING MODEL (RPM) 43 (Brattle Group 2008).

12. When the RTOs submitted their demand curves to FERC for approval, they provided supporting materials from economists. *See, e.g.*, Supplemental Affidavit of Benjamin F. Hobbs on Behalf of PJM Interconnection, L.L.C. on the September 29, 2006 Settlement Capacity Demand Curve, PJM Interconnection, L.L.C., FERC Docket Nos. ER05-1410-000 & EL05-148-000 (Sept. 29, 2006); *see also* Ming-Che Hu & Benjamin Hobbs, *Dynamic Analysis of Demand Curve Adjustment and Learning in Response to Generation Capacity Cost Dynamics in the PJM Capacity Market*, IEEE Power and Energy Society 2008 General Meeting: Conversion and Delivery of Electrical Energy in the 21st Century (2008) (publishing analysis from affidavit). For the most part, however, the analyses in these supporting materials merely modeled the results of different simulated capacity auctions to determine which alternative demand curves produced the desired balance of capacity procured and cost. In other words, the analyses did not attempt to support the derivation of the demand curves by reference to economic principles. ISO New England did link its demand curve to an analysis of the marginal impact of additional capacity on reliability. *See* Kotha, *supra* note 11, at 23. Because increases in reliability are a measure of the benefit of capacity, this idea comports with economic theory. But ISO New England then alters the reliability-quantity curve "to convert it into a price-quantity curve," without reference to economic principles. *See id*. at 24.

cretion, arbitrariness, and error. The consequences of these judgments are significant. Even small changes in demand curve parameters can cause large changes in capacity market prices and revenues.[13]

Given the importance of capacity market demand for outcomes in electricity markets, how demand is determined deserves more attention. Capacity market operators and regulators should assess the methods used to determine capacity market demand and look for ways to bring more accuracy and accountability to those methods. Fortunately, some obvious opportunities exist for improvement. Unfortunately, so far there is no indication that either the RTOs or their regulator, the Federal Energy Regulatory Commission (FERC), will avail themselves of these opportunities.[14] FERC has, however, recently demonstrated a willingness to correct other unwise existing policies, such as its much-maligned expansion of Minimum Offer Price Rules.[15] These developments suggest that the time may be ripe for FERC to initiate a rulemaking to develop a coherent approach to determining capacity market demand based on economic principles.

This article proceeds in four parts. Part I provides the necessary background, explaining the development of competitive electricity markets, the rationale for capacity markets, and the basic elements of capacity markets. The remainder of the article examines the three key components of capacity market demand. Part II addresses the capacity requirement. Part III reviews the cost of new entry. Part IV examines the shape and slope of the demand curve. Each component of capacity market demand exhibits similar flaws: a lack of foundation in economic theory, a prevalence of questionable administrative judgments, and a history of statistically biased outcomes. Regulators should hold the RTOs accountable for these shortcomings and require better market design.

II. BACKGROUND

Capacity markets are embedded in a complex larger system of electricity markets. To understand capacity demand therefore requires some knowledge of the basics of capacity market design and how capacity markets fit into the overall electricity sector. This Part provides that necessary background.

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13. For example, the model used in Section III.B.3 implies that reducing the demand forecast by one percent would have decreased revenues by approximately 4.7 percent, or about $470 million.

14. FERC primarily regulates RTO capacity markets under sections 205 and 206 of the Federal Power Act, 16 U.S.C. §§ 824d, 824e. Section 205 requires public utilities to file changes to market rules with FERC, which the agency approves if they are "just and reasonable." *Id.* § 824d(a). Section 206 allows FERC to reject an existing rule and impose a new one if it determines the existing rule is unjust and unreasonable. *Id.* § 824d(a). *See generally* ADAM VANN, THE LEGAL FRAMEWORK OF THE FEDERAL POWER ACT 2 (Congressional Research Serv. 2020).

15. *See* Ethan Howland, *PJM's 'Focused' MOPR Takes Effect, Boosting Renewables and Nuclear as FERC Commissioners Deadlock*, UTILITY DIVE (Sept. 30, 2021) (reporting that a deadlock among FERC commissioners resulted in the default approval of PJM's proposal to narrow its Minimum Offer Price Rule). For examples of critiques of FERC's orders expanding the Minimum Offer Price Rules, see, *e.g.*, Todd S. Aagaard & Andrew N. Kleit, *A Road Paved with Good Intentions?: FERC's Illegal War on State Electricity Subsidies*, 33 ELEC. J. 1 (2020); Joshua Macey & Robert Ward, *MOPR Madness*, 42 ENERGY L.J. 67 (2021). In addition to changing its policy on Minimum Offer Price Rules, FERC recently has reversed prior decisions regarding PJM's reserve markets. *See, e.g.*, *PJM Interconnection, L.L.C.*, 177 FERC ¶ 61,209 (2021).

A. Electricity Market Restructuring

Capacity markets are a relatively recent addition to the electricity sector. They arose in the late 1990s as part of a larger transition in the industry away from traditional regulation of public utility monopolies and toward competition in wholesale power markets.

Electricity grids first developed as the property of vertically integrated utility companies that owned the power plants, transmission lines, and distribution systems that comprise the electricity system.[16] Although neighboring utilities were interconnected physically, each utility company owned and operated the grid within its service territory.[17] State public utility commissions granted monopoly rights in these territories to utility companies, in exchange for which the companies incurred obligations, including duties to provide uninterrupted service to the public at 'just and reasonable' rates.[18] Federal and state regulators applying the 'just and reasonable' standard employed a cost-of-service approach that set rates for monopolist public utilities based on predicted fixed and variable costs and a reasonable rate of return on capital investments.[19] Recoverable costs and capital investments included the expense of having enough available generation capacity to meet peak demand. The public utility model operating under a cost-of-service regulatory approach is still intact, with modification, in some parts of the United States, primarily in states in the Mountain West, Plains, and Southeast.[20]

Over the last three decades, a series of complementary legal and economic developments at the federal and state level in many states led to the breakup of vertically integrated monopolies and the creation of competitive wholesale generation markets for electricity, in which power plants sold their output to still-regulated electricity distribution companies.[21] In these 'restructured' competitive markets, regulators ensured rates were 'just and reasonable' by creating competitive market conditions rather than by directly regulating rates.[22] Restructuring was intended to harness competitive market forces to reduce electricity prices

16. *See* FERC v. Elec. Power Supply Ass'n, 577 U.S. 260, 267 (2016).

17. *See* Joseph P. Tomain, *The Past and Future of Electricity Regulation*, 32 ENVTL. L. 435, 438 (2002).

18. *See* Alison Gocke, *Nodal Governance of the U.S. Electricity Grid*, 29 DUKE ENVTL. L. & POL'Y F. 205, 216 (2019).

19. *See id*.

20. *See* ENERGY INFORMATION ADMINISTRATION, STATUS OF STATE ELECTRIC INDUSTRY RESTRUCTURING ACTIVITY (Feb. 2003) (showing map with status of each state's electricity sector). As an example of one such modification, states in the Southeast recently established the Southeast Energy Exchange Market, which facilitates bilateral trading among utilities. *See Duke Energy Progress, LLC*, 177 FERC ¶ 61,080, P 2 (2021).

21. *See* Jim Lazar, ELECTRICITY REGULATION IN THE US: A GUIDE 9-10 (Regulatory Assistance Project, 2d ed. 2016).

22. *See Elec. Power Supply Ass'n*, 577 U.S. at 267.

and improve service,[23] but it also added complexity to the grid, which became a network of transactions among numerous firms.[24]

As part of the restructuring process, institutions known as regional transmission organizations (RTOs) were formed to operate the grid and coordinate transactions in competitive markets.[25] The seven RTOs in the United States now encompass all or parts of thirty-eight different states.[26] RTOs are nonprofit membership organizations that decide how to operate the grid within the RTO service territory, subject to regulatory approval from FERC.[27] Many RTO members are buyers and sellers in RTO-governed electricity markets and therefore have a financial interest in the RTO's decisions. Each RTO is responsible for grid stability in its region.[28] With literally billions of dollars at stake, the rules of capacity and other markets are often fiercely disputed.[29] This article focuses on capacity markets in the three RTOs of the Northeast United States—ISO New England, New York ISO (NYISO), and the PJM Interconnection.

RTOs operate several different wholesale electricity markets, including energy markets, ancillary services markets, and capacity markets.[30] In energy markets, generators sell electric power to load-serving entities.[31] Ancillary services markets transact power services that maintain grid stability and security, such as reserve power, reactive power, frequency regulation, and voltage support.[32] The purpose of capacity markets—which are the focus of this article—is to ensure adequate generation resources are available to meet demand for electricity at almost all times.[33]

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23. *See* REISHUS CONSULTING, LLC, ELECTRIC RESTRUCTURING IN NEW ENGLAND—A LOOK BACK 6 (Dec. 2015).

24. *See* JAMES BUSHNELL, ERIN T. MANSUR & KEVIN NOVAN, REVIEW OF THE ECONOMICS LITERATURE ON US ELECTRICITY RESTRUCTURING 6 (Feb. 23, 2017).

25. *See* Regional Transmission Organizations (Order 2000), 65 Fed. Reg. 810, 811 (Jan. 6, 2000).

26. *See* FEDERAL ENERGY REGULATORY COMMISSION, REGIONAL TRANSMISSION ORGANIZATIONS (Nov. 2015). In addition, two other wholesale market structures, the Western Energy Imbalance Market and the Southeast Energy Exchange Market, operate with some resemblance to RTO markets. *See Alabama Power Co*., 178 FERC ¶ 61,048 (2022); *Cal. Indep. Sys. Operator Corp*., 153 FERC ¶ 61,087 (2015).

27. *See* Regional Transmission Organizations (Order 2000), 65 Fed. Reg. at 811.

28. *See* Del. Div. of Pub. Advoc. v. FERC, 3 F.4th 461, 467 (D.C. Cir. 2021).

29. *See, e.g.*, *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,197 P 185 (2017) (noting the Illinois Attorney General's argument that PJM's capacity market rules were "fundamentally unfair to Illinois"); *Astoria Generating Co. L.P.*, 140 FERC ¶ 61,189 (2012) (noting the Independent Power Producers' of New York argument that NYISO's proposed capacity market rules "would product an absurd result" and had "no logical basis").

30. *See* Joel B. Eisen, *FERC's Expansive Authority to Transform the Electric Grid*, 49 U.C. DAVIS L. REV. 1783, 1793 n.44 (2016).

31. *See* TransCanada Power Mktg. Ltd. v. FERC, 811 F.3d 1, 10 (D.C. Cir. 2015).

32. *See* Regional Transmission Organizations (Order 2000), 65 Fed. Reg. at 874 (noting that ancillary services "maintain grid reliability"); *New York Indep. Sys. Operator, Inc.*, 129 FERC ¶ 61,164 (2009) (listing categories of ancillary services).

33. *PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,157 P 28 (2016).

B. Grid Reliability and the 'Missing Money' Problem

In the traditional public utility model, the regulated utilities kept their systems operating by balancing power supply and demand and were responsible for maintaining grid reliability. Monopolist utilities maintained generation capacity sufficient to meet peak demand, including a reserve margin, and recovered the costs of maintaining this capacity and a 'reasonable' rate of return on their capital investments through the regulator-approved rates they charged their customers.[34] Shortages in capacity were not generally a problem.[35] Indeed, one of the critiques of the regulated utility model is that, by virtually assuring regulated firms a return on their capital investments in generation, the model induces overinvestment in capacity.[36]

Over time, regulated utilities created physical interconnections, allowing them to transfer power from one utility company to another in a process known as *wheeling*.[37] Sometimes utility companies formed *power pools* to coordinate their generation and transmission operations.[38] These steps enabled utilities to share their generating reserves, which increased efficiency and reliability.[39] But coordination also created interdependencies in reliability across utilities, foreshadowing issues that the advent of electricity competition would pose directly.

In those parts of the country with competitive wholesale electricity markets managed by an RTO, the move to competition forced a change in managing reliability. Because operations and transactions were now occurring across firms rather than within a single firm, no single firm could be held responsible for maintaining adequate capacity. Moreover, with the advent of competition, utilities were no longer assured of earning a return on investments in capacity and instead faced incentives to cut costs. A combination of new regulatory requirements and market forces would have to be established to ensure adequate capacity.

Distinctive features of electricity—the difficulty of storing electricity, a need to balance supply and demand continuously and instantaneously, demand that is not responsive to the costs of production, the use of price caps, and the fact that the reliability of the grid must be managed system-wide, along with other factors—are perceived by scholars, policymakers, and those in the industry as contributing to an underinvestment in generation resources that threatens grid re-

34. *See* JAMES BUSHNELL, MICHAELA FLAGG & ERIN MANSUR, CAPACITY MARKETS AT A CROSSROADS 8 (Energy Institute at Haas, Apr. 2017).

35. *See id*.

36. See Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962); Richard J. Pierce, Jr., *The Regulatory Treatment of Mistakes in Retrospect: Canceled Plants and Excess Capacity*, 132 U. PA. L. REV. 497, 506 (1984).

37. *See* Joseph P. Tomain, *Electricity Restructuring: A Case Study in Government Regulation*, 33 TULSA L.J. 827, 840 (1998).

38. *See* Mark E. Haedicke, *Competitive-Based Contracts for the New Power Business*, 17 ENERGY L.J. 103, 111-12 (1996).

39. *See* Richard P. Bonnifield & Ronald L. Drewnowski, *Transmission at a Crossroads*, 21 ENERGY L.J. 447, 449 n.6 (2000).

liability.[40] This underinvestment is widely known as the 'missing money' problem.[41] In many, but not all, competitive electricity markets, RTOs have created capacity markets to address the 'missing money' problem by ensuring that the grid will have sufficient generation capacity to satisfy peak demand and thereby to avoid widespread grid failure.[42] The revenues from capacity markets are essentially an incentive payment for capital investment aimed at enhancing grid reliability. Whether or not the 'missing money' problem actually exists, and whether capacity markets are the appropriate means of addressing the "missing money" problem if it does exist, are controversial questions.[43]

C. Capacity Market Demand

Demand in capacity markets poses a fundamental design problem for system operators.[44] The RTOs and their regulator, FERC, created capacity markets to facilitate the procurement of capacity at quantities adequate to attain system reliability. Because system reliability is managed on a system-wide basis, private demand may undervalue it.[45] Without adequate private demand, the RTOs

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40. *See, e.g.*, Peter Cramton P & Axel Ockenfels, *Economics and Design of Capacity Markets for the Power Sector*, 36 ZEITSCHRIFT FÜR ENERGIEWIRTSCHAFT 115–23 (2012). As technological innovations and falling costs of battery storage add storage capacity to the grid, this may eventually alleviate at least some of the missing money problem by adding flexibility to the supply of electricity.

41. *See, e.g.*, MICHAEL HOGAN, HITTING THE MARK ON MISSING MONEY: HOW TO ENSURE RELIABILITY AT LEAST COST TO CONSUMERS 3 (2016); Peter Cramton, Axel Ockenfels & Steven Stoft, *Capacity Market Fundamentals*, 2 ECON. ENERGY & ENVTL. POL'Y, Sept. 2013, at 27, 30; Emily Hammond & David B. Spence, *The Regulatory Contract in the Marketplace*, 69 VAND. L. REV. 141, 169-70 (2016); David B. Spence, *Naïve Energy Markets*, 92 NOTRE DAME L. REV. 973, 1015 (2017).

42. *See* Jay Morrison, *Capacity Markets: A Path Back to Resource Adequacy*, 37 ENERGY L.J. 1, 44 (2016).

43. *See* TODD AAGAARD & ANDREW N, KLEIT, ELECTRICITY CAPACITY MARKETS (Cambridge Univ. Press 2022).

44. Unlike administratively constructed demand, supply in a capacity market is set by private companies in the market rather than by regulators. Electricity suppliers receive revenues from selling products into several different electricity markets, and therefore capacity market revenues are one of several potential revenue streams for a supplier. If supply in the capacity market is competitive, suppliers can be expected to bid the money they expect they will need to reach a zero economic profit, which can be thought of as the market rate of return.

45. In an ideal market, the reliability of electricity supply would be valued in the market. Reliability would have a price, and each customer would be able to purchase the amount of reliability it desired. In the context of the current electricity grid, however, reliability depends inherently on the overall electricity network. When a generator adds capacity to the grid, this enhances the reliability of the entire network, to every user's benefit. When an electricity user draws power from the grid, this reduces the reliability of the entire network, to every user's detriment. Thus, everyone using the network shares its reliability, and consumers cannot be excluded from sharing reliability. Reliability also is a non-rivalrous good, as the benefits one user receives from the network's reliability do not reduce the benefits another user gains from reliability. These characteristics of non-excludability and non-rivalry mean that reliability is what economists call a public good. *See* Malcolm Abbott, *Is the Security of Electricity Supply a Public Good?*, ELECTRICITY J., Aug./Sept. 2001, at 31; Cramton & Ockenfels, *supra* note 40, at 116-17; Dominique Finon & Virginie Pignon, *Electricity and Long-Term Capacity Adequacy: The Quest for Regulatory Mechanism Compatible with Electricity Market*, 16 UTILITIES POL'Y 143, 143-44 (2008); Paul L. Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design*, 16 UTILITIES POL'Y 159, 165 (2008); *see generally* MANKIW, *supra* note 7, at 216. Because the benefits of reliability inure to the entire network, economic theory predicts that the market will underpro-

must create demand administratively. To create demand in capacity markets, the RTOs form demand curves that are intended to produce outcomes similar to a well-functioning competitive market. Like all bureaucratic processes, however, the reality in practice diverges from the theoretical ideal.

Capacity market demand curves in the three Northeast RTOs—PJM, NYISO, and ISO New England—are a function of three elements: the capacity requirement, the Net Cost of New Entry (Net CONE), and the shape of the curve. The capacity requirement drives the horizontal dimension of the curve (quantity), the Net CONE drives the vertical dimension of the curve (price), and the shape determines the relationship between quantity and price. The remainder of this article explains how these elements come together to create capacity market demand and summarizes and evaluates the methodology used to determine each element.

III. CAPACITY REQUIREMENT

Capacity requirements are based on peak electricity demand, with an additional margin for safety. Because the primary objective of a capacity market is to ensure that sufficient capacity exists to satisfy peak levels of demand for electricity, capacity requirements are a key component of the constructed demand curve for capacity. Capacity requirements aim to achieve a level of reliability as measured by the *loss of load expectation*.[46] The loss of load expectation represents the expected frequency of outages caused by supply that does not meet demand.[47] In the United States, a common loss of load expectation is one outage in ten years.[48] This reliability goal is a widely accepted engineering-based standard that has been used for decades, with little inquiry into whether it appropriately balances the benefits and costs of achieving reliability.[49]

Three basic elements comprise a capacity requirement: annual peak load forecast, reserve margin, and resource outage rate.[50] A peak load forecast estimates peak electricity demand over the period in which capacity will be delivered.[51] The reserve margin reflects a judgment as to the amount of capacity beyond the peak load forecast that is necessary to provide the desired level of reliability that meets the loss of load expectation.[52] A typical reserve margin is fifteen percent, meaning that the RTO will seek fifteen percent more capacity

vide electricity reliability. *See* Abbott, *supra*, at 33; Cramton & Ockenfels, *supra* note 40, at 116-17; Finon & Pignon, *supra*, at 143-44; Joskow, *supra*, at 65.

46. *See* PJM INTERCONNECTION, L.L.C., PJM MANUAL 18: PJM CAPACITY MARKET 21 (Revision 49, Aug. 1, 2021).

47. *See* PJM Interconnection, L.L.C., PJM Glossary, https://www.pjm.com/Glossary.

48. *See* NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL, 2018 LONG-TERM RELIABILITY ASSESSMENT 17 (2018).

49. *See* JOHANNES PFEIFENBERGER ET AL., RESOURCE ADEQUACY REQUIREMENTS: RELIABILITY AND ECONOMIC IMPLICATIONS 83-84 (Brattle Group, Sept. 2013).

50. *See* PJM INTERCONNECTION, L.L.C., PJM MANUAL 20: PJM RESOURCE ADEQUACY ANALYSIS 31-32 (Revision 11, Aug. 1, 2021).

51. *See* PJM INTERCONNECTION, L.L.C., PJM MANUAL 19: LOAD FORECASTING AND ANALYSIS 13 (Revision 31, June 1, 2016).

52. *See* PJM INTERCONNECTION, L.L.C., *supra* note 46, at 14.

than it thinks it actually will need.[53] The resource outage rate reflects the probability that some resources will not be available to contribute their output.[54] The higher the outage rate, the more capacity the RTO will require to meet its reliability objective—that is, the higher the capacity requirement. Traditionally, the U.S. electricity grid has maintained a high level of reliability. Whether that is appropriate, and in particular whether the benefits of such high levels of reliability justify the costs of maintaining a system with so much reserve capacity, is a matter of some dispute.[55]

Peak demand forecasting has been a common element of electricity regulation for decades.[56] In traditional regulated electricity markets, monopoly utilities maintain enough capacity to meet peak demand, plus a reserve margin, and to recover the costs of maintaining this capacity and a 'reasonable' rate of return on their capital investments through the regulator-approved rates they charge their customers.[57] The regulated utility has incentives to overestimate peak demand, thereby increasing the amount of capacity, in order to justify higher revenues from the ratepayers.[58] Generators have similar incentives in restructured markets with capacity markets. The higher that forecasted peak demand is, the more capacity an RTO will purchase in its capacity market, and the more revenue generators earn.

A. Methodology

Accurate demand forecasting is difficult and requires a series of judgments. A forecasting model entails creating a statistical model that predicts demand peaks as a function of historical variables such as weather (including temperature, humidity, windspeed), population, number of residential households, employment, economic output, day of the week, whether or not the day in question is a holiday, and the stock and efficiency of various electrical equipment.[59] The actual underlying determinants of demand are inherently unknown, so the model uses these data variables as proxies for the actual determinants. Modelers at-

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53. *See, e.g.*, *Independent Market Monitor for PJM v. PJM Interconnection, L.L.C.*, 174 FERC ¶ 61,212, P 44 (2021) (noting PJM's target reserve margin of 15.8%). In May 2021, the California Public Utility Commission granted the California ISO's request to increase its planning reserve margin to 17.5% to increase reliability. *See* Hudson Sangree, *CPUC, CAISO Take Major Steps for Summer Reliability*, RTO INSIDER (May 25, 2021).

54. *See* PJM INTERCONNECTION, L.L.C., *supra* note 46, at 28-29.

55. *See, e.g.*, Iulia Gheorghiu, *PJM, NYISO and ISO-NE Pay $1.4B Annually for Excess Capacity: Report*, UTILITY DIVE (Nov. 22, 2019) (noting an estimate that "approximately $1.4 billion per year in total is wasted by the Northeast regional transmission operators and independent system operators by securing a combined 34.7 GW of excess capacity"); NORTH AMERICAN ELECTRIC RELIABILITY CORP., 2021 LONG-TERM RELIABILITY ASSESSMENT (Dec. 2021) (contending that "[c]apacity-based estimates [of reliability] . . . can give a false indication of resource adequacy").

56. *See, e.g.*, Derel W. Bunn, *Forecasting Loads and Prices in Competitive Power Markets*, 88 PROCEEDINGS OF THE IEEE 163 (2000).

57. *See* JOHANNES PFEIFENBERGER, KATHLEEN SPEES & ADAM SCHUMACHER, A COMPARISON OF PJM'S RPM WITH ALTERNATIVE ENERGY AND CAPACITY MARKET DESIGNS 13 (Brattle Group 2009); *see also supra* Part I.A (describing traditionally regulated electricity markets).

58. *See* BUSHNELL, FLAGG & MANSUR, *supra* note 34, at 9-10.

59. *See* PJM INTERCONNECTION, L.L.C., *supra* note 46, at 22-25.

tempt to choose the variables that will best predict the outcome—here, peak demand—but there is no guarantee that they choose the right variables. There is no definitive rule for determining which variables to use, or the form of those variables. In addition to using variables to create a model, forecasters may consider opinions about how demand in an area might change in ways not accounted for by the historical variables in the model.[60]

Forecasters first estimate demand peaks for each zone within the RTO territory.[61] The overall system peak demand is not, however, merely the sum of these zonal peaks.[62] This is because not all zones will reach their peaks at the same time—the peaks are said to be 'non-coincident.'[63] For example, the hour and day at which demand peaks in Chicago may not be the hour and day at which demand peaks in Baltimore. Thus, calculating total peak demand as the sum of individual zonal peaks would bias the estimated system peak upward. To adjust for this problem, forecasters model weather patterns as they affect the entire RTO area, allowing them to model the relationships between demand in different areas within the RTO and how those relationships affect total system demand.[64] This allows for the estimation of the RTO-wide system peak.

Once forecasters have created the model establishing the historical relationship between the chosen independent variables and the dependent variable to be modeled (here, overall system demand), they use the model to predict future system demand based on estimates of the independent variables used in the model—such as weather, population, and number of residential households—for the forecast year.[65] As noted above, to do so requires estimates of economic growth, growth in distributed generation and simulations of weather conditions for the future period in question, including variability in weather conditions.[66] Choosing the values for future variables is inherently difficult, and errors reduce the accuracy of a model's forecasts.

Depending on the RTO, as many as three additional steps may be required to finalize the capacity requirement. First, every RTO includes a safety margin, generally termed the *installed reserve margin*, in case generators are not available, transmission is unusually congested, or demand is above the forecasted peak. For PJM for delivery year 2018/19, for example, the forecasted peak was

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60. *See* PJM INTERCONNECTION, L.L.C., RESOURCE ADEQUACY PLANNING DEPARTMENT, 2020 LOAD FORECAST SUPPLEMENT 21-28 (Jan. 2020), https://www.pjm.com/-/media/planning/res-adeq/demand-forecast/2020-demand-forecast-supplement.ashx?la=en.

61. *See* PJM INTERCONNECTION, L.L.C., *supra* note 46, at 15.

62. *See id*.

63. *See id*.

64. *See id*.

65. *See* PJM INTERCONNECTION, L.L.C., *supra* note 46, at 17-25.

66. *See* PJM INTERCONNECTION, L.L.C., DEMAND FORECAST DEVELOPMENT PROCESS (2019), https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx.

161,418 MW.[67] Since the reserve margin was 15.7 percent, forecasted demand was increased by 15.7 percent to 186,761 MW.[68]

Second, if the forecast model has predicted demand based on installed capacity but the capacity market is conducted in terms of unforced capacity, then the forecast must be translated into unforced capacity.[69] For 2018/19, the estimated forced outage rate in PJM was 6.35 percent.[70] Together the reserve margin and the forced outage rate imply an adjustment to the forecasted peak capacity of $(1 + 0.157) * (1 - 0.0635) = (1.157 * 0.9735)$, which PJM rounded to 1.0835. This results in a capacity requirement of $161{,}418\ \text{MW} * 1.0835 = 174{,}897\ \text{MW}$.

Finally, if the RTO has an opt-out for some resources, such as the fixed resource requirement option in PJM, the capacity that has opted out of the market must be taken out of the capacity requirement.[71] In 2018/19 in PJM, 8.17 percent of resources opted out via the fixed resource requirement, and so the final capacity requirement was reduced by 8.17 percent (or, multiplied by 0.9183) to yield a final capacity requirement of 160,607 MW.[72]

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67. *See* PJM INTERCONNECTION, L.L.C., 2018/2019 RPM BASE RESIDUAL AUCTION PLANNING PERIOD PARAMETERS, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2018-2019-planning-parameters-report.ashx.

68. *See id*.

69. Installed capacity reflects a generator's theoretical availability based on nameplate output. *See* Keyspan-Ravenswood, LLC v. FERC, 474 F.3d 804, 807 (D.C. Cir. 2007). Unforced capacity reflects a generator's actual availability—that is, it discounts for the probability of an outage that renders a generator unavailable. *See id*.

70. *See* PJM INTERCONNECTION, L.L.C., *supra* note 46. A forced outage is an outage that cannot be controlled, such as a mechanical failure. *See, e.g.*, PJM INTERCONNECTION L.L.C., PJM MANUAL 22: GENERATOR RESOURCE PERFORMANCE INDICES 12 (Revision 18, Mar. 26, 2020) (defining "forced outage" as "[a] complete reduction in the capability of a generating unit due to a failure that cannot be postponed beyond the end of the next weekend"). Forced outages can be distinguished from scheduled outages for inspection or maintenance. PJM INTERCONNECTION L.L.C., PJM MANUAL 10: PRE-SCHEDULING OPERATIONS x (Revision 39, Nov. 19, 2020) ("A Generator Planned Outage is the scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with the approval of PJM"). The forced outage rate refers to the percentage of time that a power plant should have been running but was not. *See* G. MICHAEL CURLEY, RELIABILITY ANALYSIS OF POWER PLANT UNIT OUTAGE PROBLEMS 31 (General Consulting Services, LLC, 2013) (defining "forced outage rate" as "[t]he percent of scheduled operating time that a unit is out of service due to unexpected problems or failures" and noting that it "[m]easures the reliability of a unit during scheduled operation"). Scheduled outages and other periods during which a plant is not expected to run are excluded from the forced outage rate calculation.

71. When PJM created its mandatory capacity market in 2006, it included an alternative for load-serving entities that want to opt out of participation in the centralized capacity market. This opt-out option was known as the fixed resource requirement. Instead of purchasing capacity in the market, a load-serving entity can demonstrate to PJM that it owns or procures enough supply to meet its capacity obligation. *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006). ISO New England and NYISO have somewhat similar programs that allow load-serving entities to meet their capacity obligations outside of the auctions with self-supplied capacity resources. *See* ISO NEW ENGLAND INC., MARKET RULE 1: STANDARD MARKET DESIGN § III.13.1.6 (2020); NEW YORK INDEPENDENT SYSTEM OPERATOR, MANUAL 4: INSTALLED CAPACITY MANUAL 5, 36 (Version 6.46, Apr. 23, 2020).

72. *See* PJM INTERCONNECTION, L.L.C., *supra* note 46. The example calculations in the text apply to the RTOs' system-wide capacity requirement calculations. In addition, the RTOs also analyze demand within specific zones of the RTO territories and then assess, based on the availability of supply through local generation and transmission, whether to operate submarkets within the broader system-wide capacity market. *See*

B. Evaluation

1. Forecasted Demand Consistently Exceeds Actual Demand.

Two different comparisons can be used to evaluate peak demand forecasts. The first is to compare forecasted peak demand to actual peak demand. Because the purpose of a forecast model is to predict outcomes, the most obvious evaluation of the model is to compare its predicted outcome to the actual outcome. For example, for the 2018/2019 delivery year, PJM's model predicted peak demand would be 161,128 MW, and actual peak demand turned out to be 150,565 MW.[73] Thus, actual peak demand was approximately seven percent below forecasted peak demand.

A second evaluation compares forecasted peak demand to weather-normalized peak demand. Weather-normalized demand reflects forecaster's determinations of what actual demand would have been under normal weather conditions.[74] Since demand depends on weather, and weather fluctuates unpredictably, it is in some sense inappropriate to evaluate the model based on how well it predicts demand that has been influenced by weather. Weather-normalized demand attempts to remove the effect of fluctuations in weather, allowing what may be a fairer comparison of predicted peak demand to weather-normalized peak demand. For example, during the 2018/2019 PJM delivery period, weather-normalized peak demand was 149,593 MW,[75] about 7.3 percent below the forecast level of 161,418 MW.[76]

Figure 1 compares PJM's forecasted peak demand to actual and weather-normalized demand since the advent of PJM's current capacity market, known as the Reliability Pricing Model in 2009.[77] For each of the nine years in question, forecasted peak demand is above both actual peak demand and weather-normalized peak demand. On average, forecasted demand is 9 percent above actual peak demand (standard deviation of 5.36 percent) and 7.5 percent above

AAGAARD & KLEIT, *supra* note 43, at 98; *See* Kathleen Spees, Samuel A. Newell & Johannes P. Pfeifenberger, *Capacity Markets—Lessons Learned from the First Decade*, 2 ECON. OF ENERGY & ENVTL. POL'Y 1, 9 (2013).

73. *See* PJM INTERCONNECTION, L.L.C., PJM LOAD FORECAST (1999-2019) (reporting data on PJM forecast, actual, and weather-normalized peak demand); *see also* PJM INTERCONNECTION, L.L.C., LOAD FORECAST DEVELOPMENT PROCESS, https://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process.aspx (reporting forecasts since 2011). Thanks to James Wilson for supplying PJM forecasts from 1999 to 2010.

74. *See* J. STEWART MCMENAMIN, DEFINING NORMAL WEATHER FOR ENERGY AND PEAK NORMALIZATION 3 (Itron Forecasting 2008).

75. *See* PJM INTERCONNECTION, L.L.C., WEATHER-NORMALIZED PEAKS, https://www.pjm.com/-/media/planning/res-adeq/load-forecast/weather-normalized-peaks.ashx.

76. *See* PJM INTERCONNECTION, L.L.C., *supra* note 46.

77. *See* PJM Interconnection, LLC, Proposal for Reliability Pricing Model, FERC Docket Nos. ER05-1410-000 and EL05-148-000 (Aug. 31, 2005); PJM INTERCONNECTION, L.L.C., PJM LOAD FORECAST (1999-2019) (reporting data). No actual or weather-normalized peak demand data are available for the forecasted regions for 2011 and 2012. Duke Energy Ohio and Kentucky, as well as American Transmission Systems, Inc. joined PJM during those years. *See* PJM INTERCONNECTION, L.L.C., PJM HISTORY, https://www.pjm.com/about-pjm/who-we-are/pjm-history.aspx?p=1. PJM did not publish peak demand figures for the areas that matched the previous forecasts, and so no direct comparison of forecasted demand to actual demand is possible. We also exclude 2020 from our analysis, as demand was unexpectedly low during that year due to the COVID-19 pandemic.

weather-normalized peak demand (standard deviation of 2.59 percent). Both differences are statistically significant (t-statistics of 5.04 and 8.65, respectively).

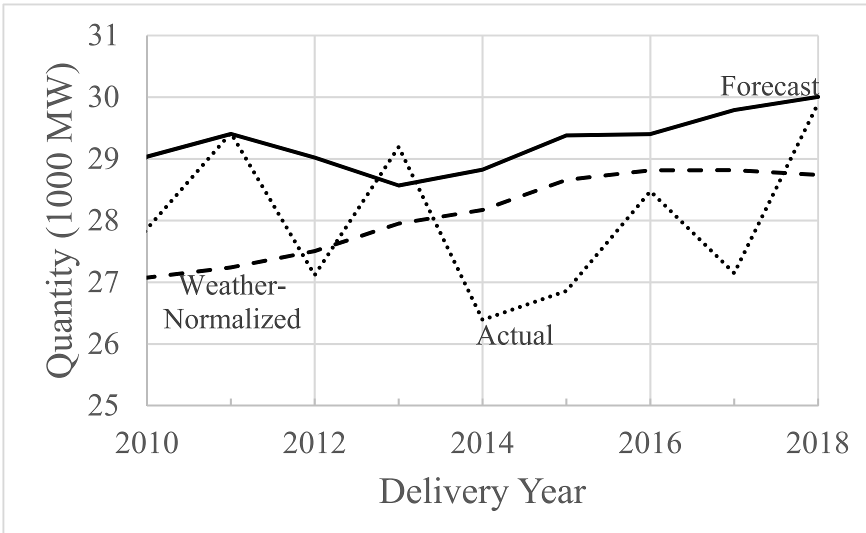

Figure 1: PJM Forecasted vs. Actual Peak Loads, 2008-2019

Figure 2 compares ISO New England's forecasted peak demand to actual and weather-normalized peak demand since the advent of ISO New England's second-generation market in 2010.[78] Forecasted peak demand exceeds actual peak demand in seven of the nine years in question. Forecasted peak demand is above weather-normalized peak demand in each of the nine years examined. On average, forecasted peak demand is 4.55 percent above actual peak demand (standard deviation of 4.52 percent) and 4.2 percent above weather-normalized demand (standard deviation of 2.26 percent). Both differences are statistically significant (t-statistics of 3.05 and 5.55, respectively).

78. *See* ISO NEW ENGLAND, FORECAST REPORT OF CAPACITY, ENERGY, LOADS, AND TRANSMISSION (various years), https://www.iso-ne.com/system-planning/system-plans-studies/celt.

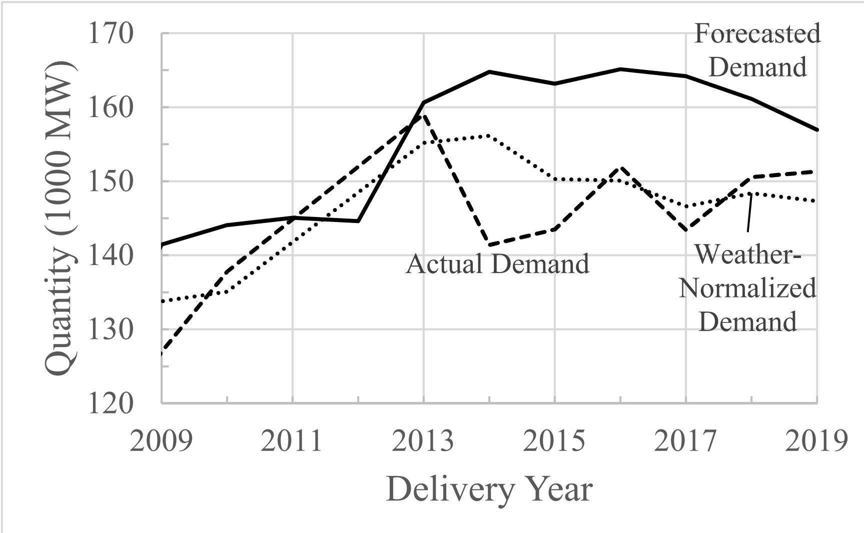

Figure 2: ISO New England Forecasted vs. Actual Peak Demand, 2010-2018

Figure 3 compares NYISO's forecasted peak demand to actual and weather-normalized peak demand since the beginning of NYISO's second-generation market in 2006.[79] The mean difference between forecasted peak demand and actual peak demand is 4.22 percent (standard deviation of 5.23 percent), a statistically significant difference (t-statistic of 3.01). Forecasted peak demand exceeds actual peak demand in ten of the fourteen relevant years.

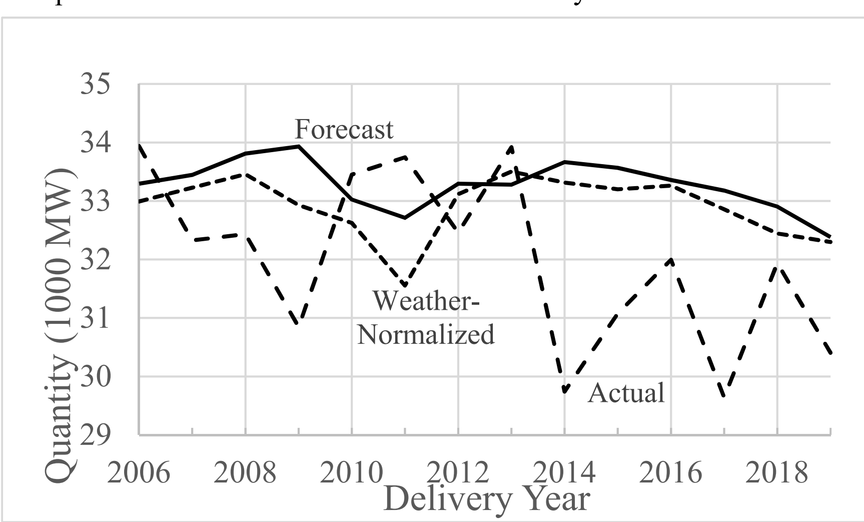

Figure 3: NYISO Forecasted vs. Actual Peak Demand, 2006-2019

79. *See* NEW YORK STATE RELIABILITY COUNCIL, L.L.C., NYSRC NEW YORK CONTROL AREA INSTALLED CAPACITY REQUIREMENT REPORTS, http://www.nysrc.org/NYSRC_NYCA_ICR_Reports.html.

Although weather-normalized peak demand is greater than forecasted peak demand in all but one of fourteen years, the mean difference is only 1.11 percent. While the difference is statistically significant (standard deviation of 1.09 percent, with a t-statistic of 3.80), this difference is far less than the 7.5 and 4.41 percent found for PJM and ISO New England. The mean forecast errors are 5.38 percent versus actual peak demand and 1.21 percent for weather-normalized peak demand.

2. Demand Forecasts Are Inaccurate and Biased.

Forecast models can be evaluated based on whether they exhibit accuracy and a lack of statistical bias. Accuracy measures how well a model's predictions match actual outcomes.[80] Because no forecast is perfect, accuracy is measured in comparative terms—that is, as among two or more forecast models, which exhibits less error. One common method of measuring forecast errors is to examine a forecast's average percentage absolute error—that is, the mean of the absolute value of the percentage errors of each forecasted value.[81]

A model also can be evaluated based on whether it exhibits statistical bias in its predictions. A good forecast is unbiased—that is, as likely to overestimate as it is to underestimate. Bias is commonly measured as the average percentage by which a model's forecasted values deviate from the actual values.[82]

Based on the data above,[83] PJM's forecasts can be compared to NYISO's forecasts to determine which forecast is more accurate and whether the forecasts are statistically biased. As noted above, PJM overestimated peak demand in every year since the advent of its RPM. Under these circumstances, when all forecasting errors are in the same direction, the average percentage absolute error of the forecasts (a measure of accuracy) equals the average percentage bias of its forecasts (a measure of bias). Thus, PJM's average percentage absolute error and average percentage bias are 9 percent against actual demand and 7.5 percent against weather-normalized demand.

By comparison, NYISO's average overestimation bias is only 4.2 percent against actual peak demand and 1.11 percent against weather-normalized peak demand. These differences are far less than those found for PJM. Because NYISO had one year when its forecast underestimated demand, its average percentage forecast error is slightly higher than its bias. The forecast error is 5.5 percent against actual demand and 1.2 percent against weather-normalized demand. Again, these differences are far less than those for PJM. Thus, NYISO's

80. *See, e.g.*, Jin Li, *Assessing Accuracy of Predictive Models for Numerical Data: Not R nor R^2, Why Not? Then What?*. 12 PLOS ONE 8 e0183250 (Aug. 24, 2017) ("Predictive accuracy should be measured based on the difference between the observed values and predicted values.").

81. *See, e.g.*, Rob J. Hyndman & Anne B. Koehler, *Another Look at Measures of Forecast Accuracy*, 22 INT'L J. FORECASTING 679, 682 (2006).

82. *See, e.g.*, E.L. Lehmann, *A General Concept of Unbiasedness*, 22 ANNALS MATHEMATICAL STATISTICS 587 (1951).

83. *See supra* Figure 1 and Figure 3.

demand forecasts are both much more accurate and far less biased than PJM's forecasts.[84]

With capacity markets, the consequences of bias can be especially harmful. A forecast of peak demand that is biased downward results in a capacity market that potentially procures less capacity than necessary, posing an increased risk of insufficient capacity. A forecast of peak demand that is biased upward results in a capacity market that procures more capacity than necessary, at an increased cost to consumers and potentially increased profits for generators.[85]

The timing of PJM's, ISO New England's, and NYISO's forecasts may explain the differences in their accuracy and bias. PJM and ISO New England operate forward capacity market auctions that run three years before the relevant commitment periods, so demand forecasts for those markets must occur three years ahead of time.[86] In contrast, NYISO's monthly capacity auctions occur just before the commitment periods in question, so its forecasts can occur much closer to the relevant times.

Forecasting demand three years in advance is inherently more difficult than forecasting less than one year in advance. Forecasting for a single year ahead versus forecasting two years earlier means an additional two years' worth of data is available for use in projections. Perhaps more important, the elements in the forecasting model that themselves need to be forecasted, such as employment and economic growth, are likely to be more accurate when determined less than a year in advance.

Based on this data for PJM, ISO New England, and NYISO, it appears running capacity market auctions three years before the delivery years in question poses a serious disadvantage. Thus, if the PJM and ISO New England markets were to eliminate the three-year period between the market auctions and the capacity delivery period, their peak demand forecasts might be more accurate.

3. The Effects of Forecast Errors Are Costly.

As explained above,[87] capacity market demand curves are anchored to the forecasted peak demand. If that forecast is in error, there are real consequences for electricity markets. The capacity market may procure too much or not enough capacity. Forecast errors also may affect the price of capacity and total

84. ISO New England's forecasts are also biased upward. See *supra* note 78 and accompanying text (reporting that ISO New England's forecasted peak demand was 4.55 percent above actual peak demand (standard deviation of 4.52 percent) and 4.2 percent above weather-normalized demand (standard deviation of 2.26 percent), with t-statistics of 3.05 and 5.55, respectively).

85. RTOs sometimes readily admit to reaching judgments that upwardly bias demand, arguing that the costs of procuring too much capacity are much lower than the costs of procuring too little. *See, e.g.*, *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183 (2014). The reserve margin embedded in the capacity requirement, however, already protects against uncertainties in demand. Moreover, reliability depends on more than just long-term resource adequacy, as problems with natural gas supply during the February 2021 electricity crisis in Texas illustrated. *See* AAGAARD & KLEIT, *supra* note 43, at 242-45.

86. Theoretically PJM's Incremental Auctions, which it operates between the Base Residual Auctions and the delivery year, could correct some of the overestimation. PJM has used its Incremental Auctions to adjust demand downward, but these are generally not enough to fully correct its overestimations in the Base Residual Auctions. *See id*. at 168-74.

87. *See supra* Part II.A.

cost of capacity, which in turn affects revenues to generators and costs to electricity consumers. Indeed, because of the inelasticity of capacity market demand curves, small changes in demand can lead to relatively large changes in capacity market prices and therefore revenues. In an effort to illustrate some of these effects, this section estimates the impacts of forecast errors on the PJM capacity market.

If the quantities and prices bid by firms were available, a supply curve could be calculated that would allow precise estimation of how forecast errors in capacity requirements affect capacity market prices and quantities. Unfortunately, most likely to protect confidential business data, PJM does not make such data available. The Brattle Group, however, has published pictorial demand curves for various delivery years.[88] (Brattle apparently had access to PJM's internal data.) We derived an approximation of PJM's supply curve from Brattle's pictorial demand curve.

Figure 4 illustrates the approximated PJM supply curve for delivery year 2018-2019. It also represents the demand curve PJM used for the capacity market, based on a capacity requirement of 160,607 MW. In the actual auction, the resulting equilibrium quantity was 166,830 MW and the market clearing price was $164.88/MW-day. This implies capacity market revenues of slightly over $10 billion.[89]

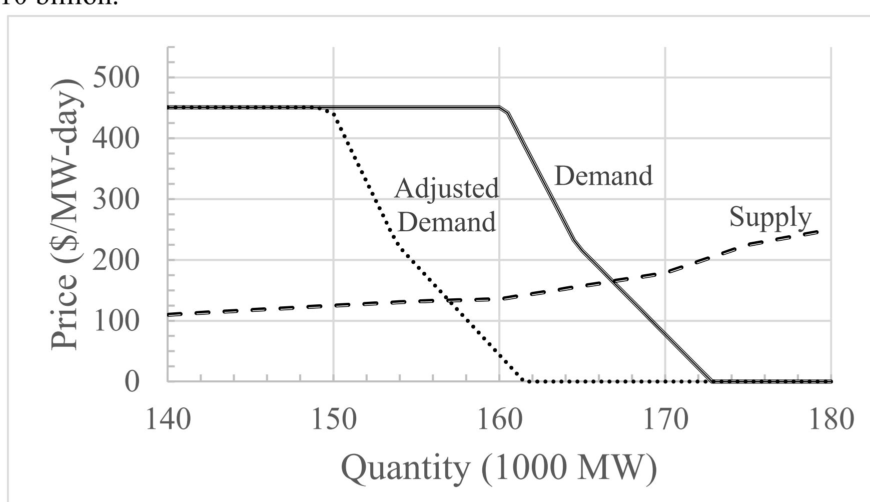

Figure 4: PJM 2018/19 Capacity Market with Adjusted Demand

Figure 4 also illustrates the adjusted demand curve that would have applied had PJM accurately forecasted peak demand at 150,565 MW, or 93.28 percent of its actual forecast. Using the method described above to translate forecasted

88. *See* SAMUEL A. NEWELL ET AL., FOURTH REVIEW OF PJM'S VARIABLE RESOURCE REQUIREMENT CURVE 42 (Brattle Group Apr. 18, 2018).

89. For simplicity purposes, here we model PJM as having one price across its various zones. In fact, some zones in PJM had prices higher than $164.88/MW-day, resulting in higher actual total capacity market revenues for 2018-19.

peak demand to an overall capacity requirement,[90] this would have resulted in a final capacity requirement of 149,808 MW. Combining the adjusted demand curve (based on this capacity requirement) with the approximated supply curve to model the market, the market-clearing outcome would have been an equilibrium quantity of 156,968 MW, with a price of $133.18/MW-day and resulting revenues of $7.62 billion. Thus, using an adjusted demand curve based on accurately forecasted demand, rather than forecasted demand that overestimated by 7 percent, would have decreased quantity by 6 percent, price by 19 percent, and annual revenues by 24 percent, or about $2.4 billion. The market-clearing quantity of 156,968 MW still would have substantially exceeded the capacity requirement of 149,809 MW, maintaining adequate reliability.

Collectively, these data and results suggest that the RTOs—and especially PJM and New England ISO—are systematically overestimating peak demand for electricity. This overestimation leads to an excess quantity of capacity, at costs to consumers of billions of dollars per year.

IV. COST OF NEW ENTRY

The cost of new entry (CONE) is meant to represent the long-run marginal cost of supply in the capacity market.[91] More specifically, CONE attempts to reflect the annualized cost—fixed costs and capital investment—of constructing and operating new generation resources that will add capacity to the grid.[92] The Northeast RTOs use CONE to shape their capacity market demand curves.[93] They define the price ceiling in each capacity market—represented in the demand curve as the horizontal top section—as a multiple of CONE.[94] In addition, they calculate the price level at other points on the downward-sloping portion of the demand curves as multiples or fractions of CONE.[95]

Gross CONE represents the total annual net revenue that a new generation resource would need to recover its capital and fixed costs.[96] This revenue can be

90. *See supra* Part II.A.

91. *See* Spees, Newell & Pfeifenberger, *supra* note 72, at 9.

92. *See New York Indep. Sys. Operator, Inc.*, 136 FERC ¶ 61,192 P 3 (2011).

93. *See, e.g.*, *ISO New England Inc.*, 155 FERC ¶ 61,319 P 38 (2016); *New York Indep. Sys. Operator, Inc.*, 156 FERC ¶ 61,039 P19 (2016); *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029 P 2 (2019).

94. *See New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 (2003); *ISO New England Inc.*, 161 FERC ¶ 61,035 P 16 (2017); *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029 P 4 (2019).

95. *See ISO New England Inc.*, 155 FERC ¶ 61,319 P 35 (2016); NEW YORK INDEP. SYS. OPERATOR, INC., *supra* note 88, at 30; PJM INTERCONNECTION, L.L.C., *supra* note 33, at 39-41 (Revision 49, Aug. 1, 2021). In addition to helping position the demand curves, Net CONE values are also used to set offer price screens for Minimum Offer Price Rules, which attempt to prevent exercises of buyer-side market power. *See* NEWELL ET AL., *supra* note 88, at 1; *see generally* Macey & Ward, *supra* note 15.

Although the Net CONE shapes the current downward-sloping demand curves, the CONE predates the second-generation capacity markets. In the first generation of capacity markets, which employed vertical demand curves, load-serving entities that failed to meet their capacity requirements were assessed deficiency charges based on CONE. *See New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 (2003); *PJM Interconnection, L.L.C.*, 115 FERC 61,079 (Apr. 20, 2006).

96. *See* NEWELL ET AL., *supra* note 88, at iii. Gross CONE excludes variable costs. *See Panda Stonewall L.L.C.*, 174 FERC ¶ 61,266 P 181 n.371 (2021). Variable costs are expected to be recovered in the energy market, because resources should not bid into the energy market at less than their variable costs.

earned in any of the available electricity markets, including the energy market, capacity market, and ancillary services market.[97] To determine the *capacity market revenue* necessary to sustain a new generation resource, Net CONE subtracts from Gross CONE the annual revenues above its variable costs that the new resource would be expected to earn in the energy and ancillary services markets:[98]

$$\text{Net CONE} = \text{Gross CONE} - \text{Energy and Ancillary Services Revenues.}$$ [99]

Net CONE thus is intended to equal the amount of 'missing money' that necessitates capacity market remuneration.[100]

A 2013 FERC staff report on capacity market design aptly observed that "calculating a value for CONE requires a number of estimations and assumptions that can be contentious."[101] At least two factors stoke controversies over CONE estimation. First, the stakes are high. The CONE value significantly affects capacity market outcomes, especially capacity prices, and therefore capacity revenues. Capacity market sellers tend to favor calculations that will lead to higher CONE values and therefore higher capacity market prices. Capacity market buyers tend to favor lower CONE values that result in lower capacity market prices. Second, as explained below, calculating CONE is also controversial because it involves numerous judgments on questions for which there is no clear answer.

A. Methodology

The stated objective of the CONE is to estimate the costs of a new plant in the capacity market.[102] The RTOs estimate Net CONE administratively by evaluating the costs of constructing and operating a hypothetical new generation resource.[103] The determination of CONE thus depends on all the factors that influence the costs of a new plant, such as plant location, technology, and configuration; engineering, procurement and construction costs; other development costs; and the cost of capital. Each of these factors involves multiple judgments that may affect the overall Net CONE estimate.

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97. *See supra* Part I.A (discussing the organized electricity markets operated by RTOs).

98. *See* PJM INTERCONNECTION, L.L.C., *supra* note 33, at 39.

99. *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183 (2014).

100. *See* JAMES F. WILSON, OVER-PROCUREMENT OF GENERATING CAPACITY IN PJM: CAUSES AND CONSEQUENCES 6 (2020); Feng Zhao, Tongxin Zheng & Eugene Litvinov, *Constructing Demand Curves in Forward Capacity Market*, 33 IEEE TRANSACTIONS ON POWER SYSTEMS 525, 531 (2018); *see also supra* Part I.B (describing the 'missing money' problem).

101. *See* FEDERAL ENERGY REGULATORY COMMISSION STAFF, REPORT NO. AD13-7-000, CENTRALIZED CAPACITY MARKET DESIGN ELEMENTS 10 (Aug. 23, 2013).

102. *See* SAMUEL A. NEWELL ET AL., PJM COST OF NEW ENTRY COMBUSTION TURBINES AND COMBINED-CYCLE PLANTS WITH JUNE 1, 2022 ONLINE DATE 2 (Brattle Group and Sargent & Lundy Apr. 19, 2018).

103. *See* NEWELL ET AL., *supra* note 88, at 5; NEWELL ET AL., *supra* note 72, at 4; NEW YORK INDEPENDENT SYSTEM OPERATOR, PROPOSED NYISO INSTALLED CAPACITY DEMAND CURVES FOR CAPABILITY YEAR 2017/2018 AND ANNUAL UPDATE METHODOLOGY AND INPUTS FOR CAPABILITY YEARS 2018/2019, 2019/2020, AND 2020/2021: NYISO STAFF FINAL RECOMMENDATIONS 1 (Sept. 15, 2016).

CONE is intended to reflect the costs of new generation in a generic sense, not the situation of any specific project.[104] Thus, estimating CONE involves creating a hypothetical competitive generation resource—known as a *reference resource*—that is meant to reflect past industry experience as well as projected future market conditions.[105] The analysis calculates the costs of the resource using a 'bottom-up' approach, so called because it estimates the total fixed costs of a resource as the sum of all expenditures required to construct the resource and bring it into operation.[106] The calculation requires numerous highly specific judgments that affect the cost of the reference resource. Some of these questions include the following:

- where the plant will be located;
- whether the plant will be constructed on a greenfield or a brownfield site;
- how much site preparation will be necessary;
- what technology the plant will use;
- how the plant will be interconnected to gas and electric infrastructure;
- whether the plant will utilize a backup fuel;
- what pollution control equipment and practices the plant will employ;
- what kind of evaporative cooling technology the plant will include; and
- how much of each type of material (e.g., concrete, masonry, steel, piping, electrical, instrumentation, insulation, painting, furnishings) will be used.[107]

These judgments collectively yield detailed specifications for the reference resource, which then must be converted into costs, requiring an additional suite of judgments. Once all these calculations are complete, the total fixed costs of a project are translated to an annualized value, which is the Gross CONE.

The 'bottom-up' tabulation of costs proceeds step by step. First, the analysis estimates the capital costs of the reference resource. The analyst selects locations for the reference resource based on areas in which new power plants have been built recently and are likely to be built in the future.[108] The analyst then selects the technical specifications for the reference resource, including characteristics such as turbine model, size, net heat rate, and environmental controls.[109] The analyst estimates the plant capital costs associated with constructing and developing a resource with the chosen characteristics. Plant capital costs are those costs incurred when constructing the power plant before the plant begins operat-

104. *See* NEWELL ET AL., *supra* note 88, at 2.

105. *See ISO New England Inc*., 161 FERC ¶ 61,035 P 16-17 (2017).

106. *See PJM Interconnection, L.L.C*., 167 FERC ¶ 61,029 (2019).

107. *See* CONCENTRIC ENERGY ADVISORS, ISO-NE CONE and ORTP Analysis 20-27 (Jan. 13, 2017).

108. *See* CONCENTRIC ENERGY ADVISORS, *supra* note 107, at 17; NEWELL ET AL., *supra* note 88, at 10-12.

109. *See* CONCENTRIC ENERGY ADVISORS, *supra* note 107, at 17-19; NEWELL ET AL., *supra* note 88, at 13; NEW YORK INDEP. SYS. OPERATOR, INC., *supra* note 92, at 3-10.

ing. Plant capital costs include owner-furnished equipment, such as the gas turbines; engineering, procurement, and construction (EPC) costs, which include other equipment, labor, and materials; and non-EPC costs, which include development costs, startup costs, interconnection costs, and inventories.[110]

Second, the CONE analysis estimates annual fixed operating and maintenance costs of the relevant power plant.[111] These costs include plant operation and maintenance, property taxes, insurance, and asset management. Variable operating and maintenance costs are not included in CONE, but they are relevant to the revenues a resource needs to earn in the energy and ancillary services markets to be financially viable.[112]

Third, the analysis uses discounting to translate the total upfront capital costs and other fixed costs of the plant into an annualized value, which is the Gross CONE. A discount rate converts the uncertain flows of future costs into a net present value. To select an overall discount rate, the RTOs use the after-tax weighted-average cost of capital method, which considers factors such as the corporate income tax rate, debt-equity ratio of project financing, cost of debt, and return on equity.[113]

Finally, the CONE analysis estimates the expected annual revenues the reference resource would earn in the energy and ancillary services markets beyond recouping its variable costs.[114] This value, known as the energy and ancillary services offset, is subtracted from the Gross CONE to yield the Net CONE. Estimating revenues in these markets depends on factors such as energy prices, ancillary services prices, fuel prices, the heat rate of the reference resource, and assumptions about how the reference resource would bid and be dispatched in these markets. None of these questions is simple to answer, and the process and standards by which RTOs address these issues is complex and often opaque.

Once the RTO's analysts have completed their CONE analysis, the analysis is reviewed through the RTO's stakeholder decision making processes.[115] The RTO may make significant changes to its analyst's recommendations.[116] In reviewing proposed changes to a CONE, FERC accords broad discretion to an RTO's judgments and seldom rejects a proposed CONE.[117]

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110. *See* CONCENTRIC ENERGY ADVISORS, *supra* note 107, at 20-27; NEWELL ET AL., *supra* note 88, at 21-22; NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., *supra* note 92, at 13-17.

111. *See* CONCENTRIC ENERGY ADVISORS, *supra* note 107, at 29-30; NEWELL ET AL., *supra* note 88, at 30-31.

112. See SAMUEL A. NEWELL ET AL., GROSS AVOIDABLE COST RATES FOR EXISTING GENERATION AND NET COST OF NEW ENTRY FOR NEW ENERGY EFFICIENCY at ii (Mar. 17, 2020).

113. *See* CONCENTRIC ENERGY ADVISORS, *supra* note 107, at 38; NEWELL ET AL., *supra* note 88, at 35; NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., *supra* note 92, at 20.

114. *See* CONCENTRIC ENERGY ADVISORS, *supra* note 107, at 49-65; NEWELL ET AL., *supra* note 88, at 19-30; NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., *supra* note 92, at 22-29.

115. *See* ISO New England Inc., ISO New England Inc., Demand Curve Design Improvements, FERC Docket No. ER16-1434, at 14 (Apr. 15, 2016); PJM INTERCONNECTION, L.L.C., QUADRENNIAL REVIEW OF VRR CURVE PARAMETERS: PJM PRELIMINARY RECOMMENDATIONS 2 (May 2, 2018).

116. *See* PJM Interconnection, Periodic Review of Variable Resource Requirement Curve Shape and Key Parameters, PJM Interconnection, LLC, FERC Docket No. ER19-105, at 17 (Oct. 12, 2018).

117. *See, e.g.*, *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183 (2014) (accepting PJM's proposed CONE values over the objections of intervenors); *ISO New England Inc.*, 175 FERC ¶ 61,172 P 16 (2021) (ac-

Given the burdens of estimating CONE, RTOs do not undertake new estimations every year. PJM, for example, estimates new CONE values every four years, with escalation rates applied to adjust the CONE in the intervening years.[118] The escalation rates are based on historical real escalation rates for various costs such as land, equipment and materials, and labor, which are then added to a forecasted inflation rate to yield nominal escalation rates.[119]

B. Evaluation

The highly detailed and specific methodology that RTOs follow in developing CONE estimates can give the process an air of scientific rigor. In reality, however, CONE estimations are rife with potentially arbitrary judgments and prone to serious error. The entire CONE process would benefit from significant changes so that capacity market demand curves can better reflect market forces and contribute to the integrity of the markets.

1. Estimating CONE Involves Indeterminate Judgments.

The process of estimating CONE requires making a series of discretionary judgments on which there is no clear answer. Take, for example, the selection of a technology for the reference resource on which the CONE is based. Much of the controversy over a CONE estimate often centers on the choice of technology for the reference resource.[120] But guidance regarding how to select a reference technology is sparse and scattered.

Methodological uncertainty regarding selection of a reference technology appears rooted in ambiguity about precisely what the CONE is supposed to represent. Conceptually, because Net CONE is meant to embody the long-run marginal cost of supply in the capacity market, the reference resource should correspond to the long-run marginal market-clearing resource in the capacity market. Commenters, including a 2013 FERC staff report, have accordingly linked CONE to the marginal capacity resource that clears the market.[121] Moreover, the RTOs use their Net CONE estimations as if this were the case. Each of the capacity market demand curves includes a point—sometimes called a reference point—near the quantity of the capacity requirement and the price of Net CONE.[122] The expectation is that this reference point will be the long-term equilibrium market-clearing price and quantity. This implies that Net CONE is the

cepting ISO New England's proposed CONE values over the objections of intervenors); *New York Indep. Sys. Operator, Inc.*, 136 FERC ¶ 61,192 P 71 (2011) (accepting NYISO's proposed CONE values over the objections of intervenors).

118. *See* NEWELL ET AL., *supra* note 88, at 1.

119. *See* NEWELL ET AL., *supra* note 88, at 29. The RTOs estimate Net CONE locally for each zone as well. *See id*. at 16.

120. *See, e.g.*, *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029 P 31-62 (2019); *New York Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,299 (2008).

121. *See* Jonathan Falk, *Capacity Markets: Prices vs. Quantities*, 7 NERA ECONOMIC CONSULTING ENERGY MARKET INSIGHTS 1, 2 (2010); FEDERAL ENERGY REGULATORY COMMISSION STAFF, *supra* note 101, at 32.

122. *See New York Indep. Sys. Operator, Inc.*, 144 FERC ¶ 61,126 P 7, 31 (2013).

annual capacity market revenue needed for the marginal market-clearing resource to be economically viable.

The criteria that RTOs articulate to guide their selection of a reference technology do not, however, point to choosing a marginal market-clearing resource. Indeed, despite the strong similarities in the processes they use to estimate CONE, each RTO has described the selection of a reference technology differently, and none of the RTOs appears to have explained or justified its selection criteria by reference to any discernible economic theory. Consider the following examples:

- PJM has indicated that the technology should be "representative of a peaking unit in the energy market that derives a significant portion of its revenues from the capacity market."[123]
- PJM's independent consultant, the Brattle Group, has recommended selecting a reference technology based on five factors: (1) the technology is technically feasible; (2) the technology is economically viable; (3) the technology has a standard set of characteristics and costs; (4) the costs of the technology can be estimated with confidence; and (5) the technology will stay viable as a reference technology.[124]
- ISO New England has articulated a three-factor inquiry for choosing a reference technology: (1) the technology is "likely to be developed in New England"; (2) the RTO "could develop cost and revenue estimates . . . with confidence"; and (3) the technology "should produce prices high enough to meet the reliability standard but not so high as to add unnecessary costs."[125]
- ISO New England also has stated that it chose a reference resource that represents "the technology that is expected to be the most economically efficient and that is commercially available to new capacity suppliers."[126]
- NYISO's tariff specifies that the reference technology must be an economically viable peaking unit with the lowest fixed costs and highest variable costs.[127]

FERC has approved CONE estimations based on these various formulations, without adding its own clarification or unified standard.[128]

123. *See* PJM INTERCONNECTION, L.L.C., QUADRENNIAL REVIEW OF VRR CURVE PARAMETERS: PJM PRELIMINARY RECOMMENDATIONS 4 (May 2, 2018).

124. *See* JOHANNES P. PFEIFENBERGER ET AL., THIRD TRIENNIAL REVIEW OF PJM'S VARIABLE RESOURCE REQUIREMENT CURVE 28 (Brattle Group, May 15, 2014).

125. *See ISO New England Inc.*, 161 FERC ¶ 61,035 P 38 (2017).

126. *See ISO New England Inc.*, 170 FERC ¶ 61,052 P 7 (2020).

127. *See New York Indep. Sys. Operator, Inc.*, 125 FERC ¶ 61,299 (2008).

128. The lack of scrutiny FERC gives to an RTO's choice of reference technology is aptly illustrated by a 2017 order in which FERC observed that "ISO-NE's Tariff is not prescriptive as to how the reference technology should be chosen" but nevertheless concluded that ISO New England's selection of a combustion turbine as the reference technology was "consistent with the requirements of the Tariff." *ISO New England Inc.*, 161 FERC ¶ 61,035 P 37 (2017). In other words, ISO New England's choice complied with its nonexistent requirements.

None of these criteria is based on market principles, and none points clearly to marginal market-clearing plants. Several of the criteria refer to choosing a reference technology that is "feasible," "viable," "likely to be developed," "economically efficient," and "commercially available"—characteristics that describe any resource that clears the market, not marginal market-clearing resources in particular. Other criteria focus on whether costs can be estimated with confidence. That may help to estimate costs associated with a given technology, but it does nothing to ensure that the RTO has chosen the right technology to analyze in the first place. Further, the references to peaking units, or similarly to high variable costs, do not necessarily focus on marginal market-clearing plants. The rationale for capacity markets suggests a focus on peaking units,[129] but a peaking unit is not necessarily marginal in the capacity market just because it clears the market.[130]

Some economists have posited that, in theory, the long-term cost of each technology should be equal for the marginal unit for each technology that will be competitive in the market.[131] If that holds true, then the selection of a resource technology might not affect the CONE estimation. But the results of actual CONE estimations do not reflect this theory, as costs can vary significantly across technologies. For example, in the PJM market in 2018, the Net CONE for a simple combustion turbine was 8-12 percent higher than a Net CONE for a combined-cycle plant.[132] These intermediate judgments can cumulatively make a large difference in the CONE, and there is no clear framework guiding RTOs in exercising their discretion in making the judgments. The result is a cacophony of decisions without clear rationales.

CONE estimations at PJM and ISO New England illustrate the discordance. A core question in each process was the selection of a reference technology. When ISO New England selected a reference technology in its 2017 Net CONE calculation, it chose a simple combustion turbine.[133] In recommending a combustion turbine as the reference technology, ISO New England's consultant, Concentric Energy Advisors, noted that a combustion turbine was "substantially less expensive" than other technologies, was well established in the New England region, and had participated in and cleared recent capacity auctions in New England.[134] Concentric concluded that "the simple cycle technology is a cost-effective technology that has gained commercial acceptance and is economically viable in New England." ISO New England adopted Concentric's recommendation, noting the combustion turbine's low cost relative to other technologies and

129. The 'missing money' theory that serves as a justification for capacity markets tends to focus on inadequate revenues for peaking plants in the energy market. *See, e.g.*, PETER CRAMTON & STEVEN STOFT, THE CONVERGENCE OF MARKET DESIGNS FOR ADEQUATE GENERATING CAPACITY 3 (2006).

130. Here, the marginal unit in the capacity market will be the resource with the highest accepted bid, which therefore sets the market price.

131. *See* PFEIFENBERGER ET AL., *supra* note 124, at 27.

132. *See* NEWELL ET AL., *supra* note 88, at iv.

133. *See ISO New England Inc.*, 161 FERC ¶ 61,035 P 19-21 (2017).

134. *See* CONCENTRIC ENERGY ADVISORS, supra note 107, at 5-6.

market conditions in the New England region that favored the development of combustion turbine plants.[135] FERC approved the choice.[136]

By contrast, PJM also chose a combustion turbine as its reference technology in 2018 but for entirely different reasons and under much different circumstances. In its 2018 review of PJM's CONE, the Brattle Group recommended adopting a natural gas-fired combined-cycle turbine as the reference technology for CONE, because of its lower costs and prevalence in new generation.[137] Combined-cycle turbines have dominated new generation in PJM since 2005.[138] As of 2018, over the previous ten capacity auctions—that is, since the auction held in 2010 for Delivery Year 2012/13—28,181 MW of new combined-cycle plants had entered the market, versus just 3725 MW of combustion turbine plants.[139] The Brattle Group's recommended Net CONE for combined-cycle turbines was, depending on the zone, between 25 and 63 percent below Brattle's recommended updated Net CONE for a combustion turbine.[140] Given the cost disparity, Brattle noted that going forward combustion turbines might not even remain competitive in the PJM market.[141]

PJM rejected the Brattle Group's recommendation and decided to continue basing its Net CONE on the combustion turbine technology.[142] Despite the lower per-megawatt cost and prevalence of combined-cycles, PJM reasoned that combustion-turbine plants, as peaking plants, depend on capacity market revenue more than combined-cycle plants do.[143] In addition, PJM argued that combustion-turbine plants could be brought to market less expensively (on a per-plant basis) and more quickly than combined-cycles; that cost estimates of combined-cycles were more uncertain than for combustion turbines; and that both NYISO and ISO New England continued to use combustion turbines as their reference technology. FERC deferred to PJM's position, which it deemed reasonable.[144] It noted that two combustion turbine plants had entered the PJM market since 2014—but did not note the over seven and a half times as many megawatts of combined-cycle plants that were added during the same period.

That ISO New England and PJM could reach such different decisions after applying such different standards in choosing their reference technologies demonstrates the indeterminacy of the CONE process. In choosing its reference technology, ISO New England relied heavily on precisely the factors—lower CONE and commercial viability—that PJM rejected in making its choice. FERC

135. *See ISO New England Inc.*, 161 FERC ¶ 61,035 P 19-21 (2017).

136. *See ISO New England Inc.*, 161 FERC ¶ 61,035 P 36-39 (2017).

137. *See* NEWELL ET AL., *supra* note 88, at 17.

138. *See id*. at 5.

139. PJM INTERCONNECTION, L.L.C., 2021/2022 RPM BASE RESIDUAL AUCTION RESULTS 22 (May 23, 2018).

140. *See* NEWELL ET AL., *supra* note 88, at 17.

141. *See id*. at 33.

142. *See* PJM INTERCONNECTION, L.L.C., QUADRENNIAL REVIEW OF VRR CURVE PARAMETERS: PJM PRELIMINARY RECOMMENDATIONS 4 (May 2, 2018); *PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029 P 33 (2019).

143. *See* PJM INTERCONNECTION, L.L.C., *supra* note 116, at 128.

144. *See PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,029 P 59, 61 (2019).

readily approved both decisions, without trying to clarify the standard or explain how both decisions could be permissible interpretations of CONE.

State public advocates and an environmental organization petitioned the D.C. Circuit for review of FERC's approval of PJM's proposed CONE, raising two arguments.[145] First, the petitioners argued that FERC "erred by not applying its 'established framework' for evaluating an RTO's choice of Reference Resource."[146] According to petitioners, in previous cases FERC had evaluated a proposed reference resource based on three factors: "(1) whether the unit is likely to be developed in the region, (2) whether cost and revenue estimates for that unit can be developed with confidence and (3) whether the [demand curve] produces prices high enough to meet the reliability standard while not adding unnecessary costs."[147] The court rejected this argument, noting that FERC had applied these factors in just one prior case and therefore they did not represent an established framework the Commission was obligated to apply in every case involving a choice of reference resource.[148] FERC's lack of a consistent or coherent approach to choosing a reference resource thus allowed the agency to continue acting inconsistently without exceeding its statutory discretion.

Second, the petitioners argued that FERC's approval of a combustion turbine as the reference resource was unjust and unreasonable.[149] The court rejected this argument as well. Just as FERC had deferred to PJM's selection despite the predominance of combined cycle natural gas plants among new capacity in the PJM region, the court deferred to FERC's approval of a combustion turbine as the reference resource.[150] The court reached this conclusion while conceding that "PJM's proposed combustion turbine plant resulted in a VRR Curve over four times more protective than the Reliability Requirement envisions" and "costs consumers $140 million more each year."[151] If FERC wants to approve an outcome that adds excess reliability at significant cost, the Federal Power Act gives it discretion to make that policy decision.[152]

145. *See* Del. Div. Public Advocate v. FERC, 3 F.4th 461 (D.C. Cir. 2021); *see also, e.g.*, PJM Interconnection, L.L.C., 128 FERC ¶ 61,157, 61,778 (2009) (rejecting a similar challenge arguing that PJM had overestimated Net CONE by choosing the wrong reference technology). In addition, the petitioners also argued that FERC erred in approving a ten percent adder for the Net CONE value. *See* 3 F.4th at 468. PJM rules allowed generation resources to bid into the energy market at 10% above their variable costs to account for cost uncertainties, and in developing its Net CONE PJM included a ten percent adder. The court agreed with the petitioners that the adder was arbitrary and capricious, because the record did not support the conclusion that a resource of the type represented by the reference resource would bid above its variable costs. *See id*. at 469.

146. *See id*. at 465.

147. *See id*. (citing ISO New England Inc.,147 FERC ¶ 61,173 PP 32–33 (2014)).

148. *See id*. The DC Circuit further noted that FERC had concluded that PJM's proposal was just and reasonable even applying the factors. *See id*. at 465 (citing *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,040 P 14 (2020).

149. *See id*.

150. *See id*. at 467; *see generally* Emily Hammond, *Double Deference in Administrative Law*, 116 COLUM. L. REV. 1705 (2016) (evaluating deferential judicial review of agency decisions that in turn defer to nongovernmental standard-setting organizations).

151. *See id*. at 467-68.

152. *See id*. at 468.

Given FERC's broad discretion under section 205 of the Federal Power Act, the D.C. Circuit may have been correct in holding that the Commission acted within its authority in approving PJM's Net CONE, despite the inconsistency between PJM's approach and ISO New England's approach to its Net CONE just two years earlier.[153] But even if FERC's decisions were arguably legally defensible, they were bad policy. In the face of uncertainties in estimating Net CONE, FERC should not simply always err on the side of more reliability; this approach costs electricity customers hundreds of millions of dollars each year, with little in the way of benefit to show for it.

FERC and the RTOs need a coherent policy for how to determine an appropriate value for Net CONE. Given the frequency with which this issue arises—each RTO reassesses its Net CONE every few years, and each reassessment requires FERC approval—and the lack of a consistent methodology for choosing a reference resource, FERC should undertake a rulemaking process to develop a predictable and thoughtful approach to choosing a reference resource.

2. CONE Is Consistently Overestimated.

CONE estimations also can be evaluated on how well they match market results. The long-term capacity market-clearing price should equal the Net CONE.[154] This is because, if the capacity market is meeting its objective of inducing new resources to enter the market with the quantity of capacity necessary to meet capacity requirements, then the capacity price should equal the additional revenue—beyond that earned in other electricity markets—necessary to induce new resources to enter the market.

Again, reality does not match the theory. Capacity prices in all three Northeast RTOs are consistently well below Net CONE. The Brattle Group calculates that market-clearing prices in the PJM capacity auction have been on average sixty percent below PJM's Net CONE.[155] Wilson similarly calculates that, over the period from Delivery Year 2015 to 2021, PJM's Net CONE was more than double the three-year running average market-clearing price.[156]

Figure 5 compares Net CONE values to market prices for two areas within PJM. The first is the generally unconstrained area in PJM (generally referred to as "RTO" or "rest of RTO"), usually centered on Ohio. The second is the Mid-Atlantic Area Council ("MAAC") area, centered on Philadelphia.

153. Although under section 205 FERC does not have authority to revise an RTO's proposal, *see* Advanced Energy Mgmt. All. v. FERC, 860 F.3d 656, 662 (D.C. Cir. 2017), the Commission has the power to adopt substantive standards under section 205 and section 206 and then evaluate proposals under section 205 based on whether they comport with the agency's standard. *See, e.g.*, Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities, Order No. 888, 61 Fed. Reg. 21,540, 21, 541 (1996).

154. *See* NEWELL ET AL., *supra* note 88 at 15 (Apr. 18, 2018); WILSON, *supra* note 100, at 6.

155. *See* NEWELL ET AL., *supra* note 88, at 4.

156. *See* WILSON, *supra* note 100, at 6.

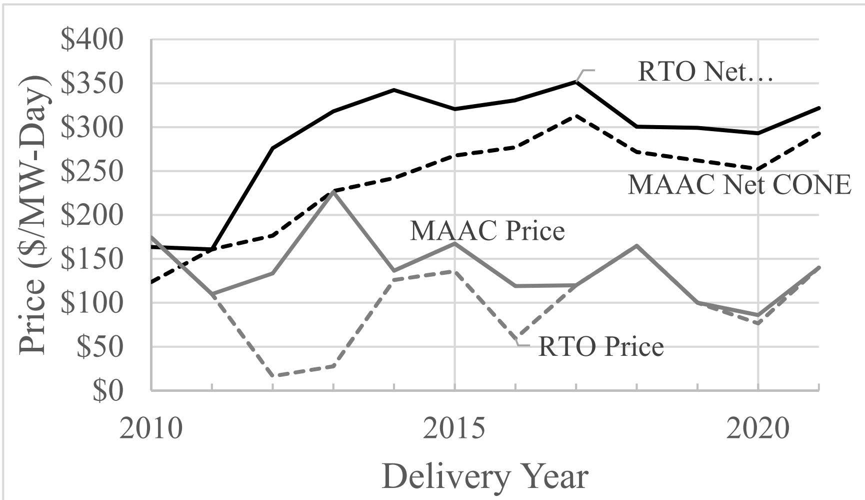

Figure 5: PJM Net CONE vs. Market Price, 2010-2021

As Figure 5 indicates, at the beginning of PJM's second-generation market, Net CONE and market prices were fairly close to each other. This quickly changed, however. Over the time period examined, RTO market prices averaged only 32.5 percent of RTO Net CONE values (t-statistic 7.59). Over the same period, MAAC market prices averaged less than 55 percent of Net CONE values (t-statistic 4.98). Net CONE values were greater than market prices for every market year in both zones since 2010.

NYISO has reported that its market-clearing prices "have been consistently below forty percent" of its Net CONE.[157] Our analysis is consistent with that observation. Since the outset of its capacity market, NYISO has divided its territory into three regions for capacity purposes: Upstate New York, New York City, and Long Island.[158] In 2013, NYISO split off an area in the Lower Hudson Valley from the Upstate region.[159] Figure 6 presents the Net CONE values and the twelve-month running average capacity market prices for Upstate and New York City since the outset in 2005 of the NYISO second-generation market.[160]

157. *See* NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., 2018 ANNUAL INSTALLED CAPACITY REPORT 6 (2018).

158. *See Central Hudson Gas & Electric Corp.*, 88 FERC ¶ 61,138 (1999).

159. *See* New York Indep. Sys. Operator, Inc., 144 FERC ¶ 61,126 (2013).

160. NYISO operates monthly capacity auctions. *See* NEW YORK INDEPENDENT SYSTEM OPERATOR, MANUAL 4: INSTALLED CAPACITY MANUAL 157 (Version 6.49, May 2021). Because these prices are highly seasonal, we present twelve-month running averages in Figure 6.

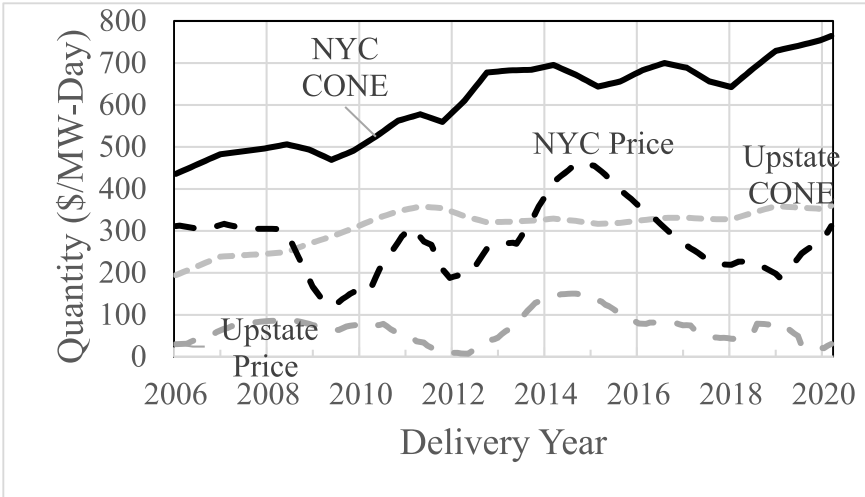

Figure 6: NYISO Net CONE vs. Market Price, 2005-2020

As Figure 6 indicates, the twelve-month running average prices (as well as monthly prices) for New York City and for Upstate New York have been below their corresponding Net CONE for each of the 177 months since 2005. During this period, the average capacity market price for New York City was $278.19/MW-day, 45.8 percent of the average Net CONE value of $607.73/MW-day. (The t-statistic for the differences is 11.73.) For Upstate New York, the average capacity price was $67.79/MW-day, only 21.9 percent of the average CONE value. (The t-statistic for the difference is 18.77.)[161]

Interpreting ISO New England market data is somewhat more complex. Prior to delivery year 2018/2019, ISO New England used a vertical market demand curve with minimum and maximum prices. The result was that in each year the capacity market price was determined administratively. Since that time, there have been six annual auctions. In these auctions the market price averaged slightly less than 55 percent of Net CONE. The market prices ranged from 24 to 86 percent of Net CONE, as displayed in Figure 7.[162]

161. For simplicity of presentation, we do not present prices or Net CONE values for either Long Island or the Lower Hudson Valley area. For Long Island, the average price of $126.10/MW-day was 33.2 percent of the average CONE of $379.87 (t-statistic 10.25). For the Lower Hudson Valley, the average market price of $192.42 was 38.3 percent of the average CONE of $502.28.

162. *See* ISO NEW ENGLAND INC., FORWARD CAPACITY MARKET PARAMETERS (Mar. 6, 2020), https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/; ISO NEW ENGLAND INC., RESULTS OF ANNUAL FORWARD CAPACITY AUCTIONS (2020), https://www.iso-ne.com/about/key-stats/markets#fcaresults.

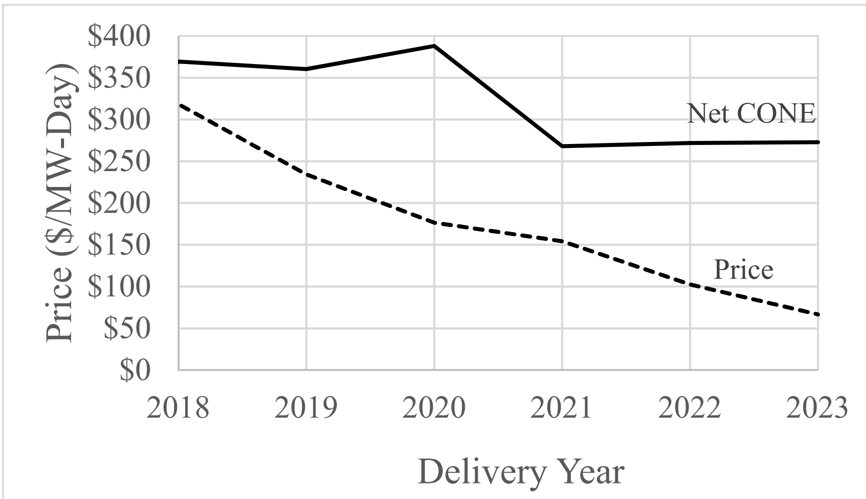

Figure 7: ISO New England Net CONE vs. Market Price, 2018-2023

The RTO capacity markets are exceeding their reliability objectives. Substantial quantities of new generation have cleared the auctions, resulting in overall capacity levels more than sufficient to meet reliability requirements.[163] Given that the capacity markets are clearing plenty of capacity at prices much lower than Net CONE, the RTOs' Net CONE values are obviously too high.

3. The Effects of CONE Overestimation Are Costly.

As with peak demand forecasts, models can estimate the effects of overestimating Net CONE on market outcomes. Our model employs the same approximated PJM supply curve described above that was used in modeling the impact of different peak demand forecasts.[164] Using this supply curve, we compared the market results of the demand curve PJM used for the 2018/2019 auction with the modeled results of an adjusted demand curve based on a Net CONE that was 50 percent lower. We reduced the value of Net CONE by 50 percent as a rough approximation of the proper CONE. As our purpose is to show the sensitivity of market results to the value of CONE, the exact level of CONE is not critical for this analysis.

Figure 8 illustrates the modeled demand and supply curves. Recall that, in the actual 2018/2019 PJM auction, the equilibrium quantity was 166,830 MW and the price was $164.88/MW-day, implying total capacity market revenues of slightly over $10 billion. Using the adjusted demand curve (based on a 50 percent Net CONE value), the market-clearing outcome would have been an equilibrium quantity of 163,233 MW with a price of $149.40/MW-day, resulting in

163. *See* NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., 2018 ANNUAL INSTALLED CAPACITY REPORT 6 (2018); WILSON, *supra* note 100, at 7.

164. *See supra* Part II.B.3.

revenues of slightly less than $9 billion. Thus, using an adjusted demand curve based on a 50 percent Net CONE level, rather than the overestimated actual Net CONE, would have decreased quantity by 2.2 percent, price by 9.4 percent, and annual revenues by 11.3 percent, or about $1.1 billion. The equilibrium quantity of 163,233 MW still would have significantly exceeded PJM's capacity requirement of 160,607 MW.

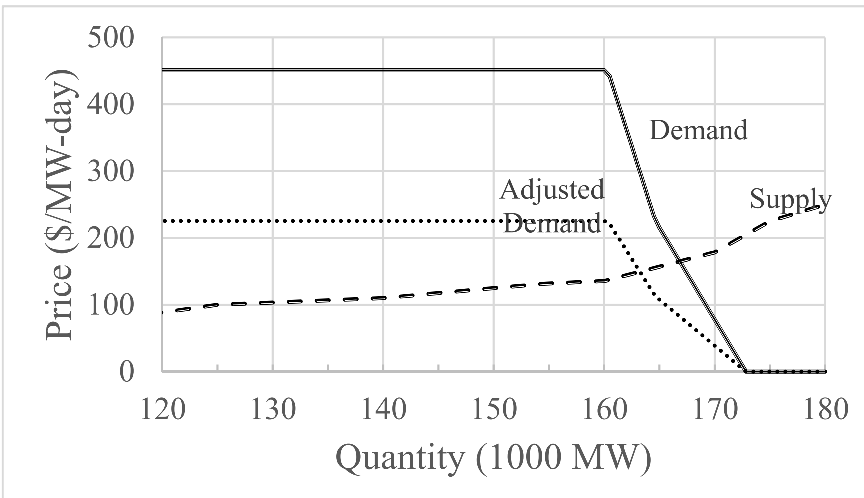

Figure 8: PJM 2018/2019 Capacity Market with Adjusted Demand

Although substantial, the effects of a lower Net CONE value on market outcomes are smaller than the effects of an accurate peak demand forecast as modeled above. As Figure 4 illustrates, an accurate peak demand forecast shifts the demand curve to the left, which affects price and especially quantity significantly. By contrast, as Figure 8 illustrates, a lower Net CONE value shifts the demand curve down, which has a smaller effect on price and quantity.[165]

4. The Entire CONE Methodology Is Flawed.

Consistent overestimation of Net CONE values across all three Northeast RTOs strongly suggests that the entire methodology for calculating Net CONE is fundamentally flawed. The RTOs calculate Net CONE through a bottom-up, engineering-based administrative process based on judgments about a hypothetical new power plant. This process is filled with challenging decisions that are difficult to review and appears to yield Net CONE values that are consistently biased upward.

The administrative method that RTOs use to estimate Net CONE in many ways resembles the process that FERC and state public utility commissions em-

165. If our model uses both actual peak demand rather than forecasted peak demand and a Net CONE equal to 50 percent of the Net CONE PJM used, the resulting equilibrium would have a price of $129.53/MW-day, a quantity of 153,233 MW, and revenues of $7.24 billion. This would have been nearly 28 percent below actual revenues.

ployed to set cost-of-service rates prior to restructuring and that state commissions continue to use in those states that have not restructured their electricity markets.[166] Net CONE estimations and cost-of-service rate cases have different objects of analysis—Net CONE estimations analyze the fixed costs of a single power plant, whereas rate cases analyze the total costs of an entire public utility—but their similarities are otherwise remarkable. Like the CONE analysis, a cost-of-service ratemaking uses a bottom-up administrative process to estimate the costs of production in order to determine the revenues necessary for financial viability.[167] Like the CONE analysis, a cost-of-service ratemaking relies on hypothetical expenses and projected market conditions.[168] Like the CONE analysis, complicated questions regarding the cost of capital financing play a major role in rate cases. The answers to these questions are difficult to unravel and play a major role in rate cases.[169] While it is understandable that utility regulators have adopted new processes that resemble their traditional methods, this continuity runs contrary to the goal of restructuring, which was to replace complicated administrative processes with markets.

The Net CONE is intended to represent an annualized amount of money that would induce a competitive new generation resource to enter the market. CONE estimation uses a cumbersome and opaque administrative process to estimate the costs of a hypothetical plant. This entire complex process is unnecessary. Instead, the value of the Net CONE could be determined more accurately and easily by reference to an empirical measure of the actual cost of new entry.

An empirically derived Net CONE would bring several advantages over the current method of administrative CONE estimation. Estimating CONE empirically—for example, as a multi-year running average market-clearing price[170]—would add integrity to capacity markets. Net CONE is a crucial parameter driving the shape and position of the capacity market demand curve, and therefore an important determinant of market outcomes. Because an administrative Net CONE estimates the future costs of a stylized hypothetical plant, it is inherently unclear whether the process has yielded the 'right' answer. An empirical Net CONE based on market-clearing prices has by definition cleared the capacity market at quantities sufficient to meet reliability requirements. In other words,

166. *See supra* Part I.A (discussing the transition from traditional ratemaking to restructured electricity markets). In addition, FERC still uses cost-of-service ratemaking for transmission, and states use cost-of-service ratemaking for distribution, neither of which is conducive to competition. *See* James W. Moeller, *Public Utilities and Environmental Justice: Electric Restructuring and Deregulation and Low-Income Communities*, 21 U.D.C. L. REV. 1, 4 (2019).

167. *See* A. Lawrence Kolbe & William B. Tye, *The Duquesne Opinion: How Much "Hope" Is There for Investors in Regulated Firms?*, 8 YALE J. REG. 113, 117 (1990); Michael E. Small, *A FERC Electric Rate Primer*, 5 ENERGY L.J. 107 (1984).

168. *See* Inara Scott, *Teaching an Old Dog New Tricks: Adapting Public Utility Commissions to Meet Twenty-First Century Climate Challenges*, 38 HARVARD ENVTL. L. REV. 371, 383 (2014).

169. *See* David A. Lander, *Public Utility Rate Design: The Cost of Service Method of Pricing*, 19 ST. LOUIS UNIV. L.J. 36, 37 (1974).

170. *See* WILSON, *supra* note 100, at 6. Wilson critiques PJM's Net CONE values by comparing them to a more accurate empirical Net CONE calculated from a three-year running average capacity price, but he does not directly propose that PJM should use an empirical CONE methodology.

an empirical Net CONE has proved adequate to induce investment in new generation at least cost—which is exactly what the Net CONE is supposed to do.

An empirical CONE would greatly simplify the process for selecting CONE values. Instead of a complicated calculation built on numerous judgments about a hypothetical future power plant, CONE would be easily calculated from already existing market data.

Taking the judgments out of the CONE process also would reduce the politics in the process. Under the current method, administrative CONE estimations are often highly controversial, because (a) they involve numerous judgments as to which there is no clear answer; and (b) CONE significantly affects capacity market prices, which in turn affects the revenues of generators and the costs of load-serving entities. The existing administrative process for estimating CONE requires RTOs to make a series of controvertible judgments, to which FERC has given the RTOs wide latitude. Although putatively designed as an expert-driven, bottom-up calculation, the stakeholder politics of RTO decision making create opportunities for rent-seeking and political jockeying in the CONE estimation. Switching to an empirical CONE would remove these arbitrary judgments and replace them with an empirical calculation, and in doing so would take away the opportunity for stakeholders to influence the CONE to their advantage.

A crucial shortcoming of the current CONE process is that RTOs are not being held accountable for consistently overestimating CONE. This lack of accountability allows the overestimation to continue unabated. An empirical CONE, by contrast, would be self-correcting, thus automatically adding built-in accountability to the process. An empirical CONE would admittedly not be entirely accurate—costs change, and previous costs do not perfectly predict future costs. But given the dismal record of current estimation methods, an empirical CONE likely would do better. At the very least, an empirical methodology would be less subject to manipulation and rent seeking through the political stakeholder process.

The RTOs do have some experience with using empirical data to estimate CONE inputs. Until 2020, for example, PJM based its energy and ancillary services offset on the three previous years of historical data.[171] In 2020, FERC required PJM to change this approach to an estimate based on forecasted revenues in the energy and ancillary services market, noting that using an empirical estimate "based on three years of historical data is easily distorted by anomalous market conditions in one year that are not representative of what market participants can expect in future delivery years."[172] Then, in 2021, FERC, now under Chairman Glick's leadership, reversed that conclusion, concluding that the record did not support a finding that PJM's backward-looking historical approach was unjust and unreasonable, and restored PJM's empirical approach.[173]

Even if the RTOs are not going to replace their administrative CONE estimations with empirical CONE measures, FERC should use empirical market results to hold the RTOs accountable for their CONE estimations. FERC should

171. *See* PJM Interconnection, L.L.C., 171 FERC ¶ 61,153 P 282-83 (2020).

172. *See id*. at P 313.

173. *See PJM Interconnection, L.L.C.*, 177 FERC ¶ 61,209 P 25 (2021).

require RTOs to explain divergences between their administrative estimates and empirical results and to take concrete steps toward achieving more accurate forecasts. Regrettably, FERC has not shown either the willingness or ability to carry out this modest oversight task. Instead, when presented with objections noting the inaccuracies of CONE forecasting, FERC has claimed the need to protect reliability—contrary to results showing that the RTOs have more than enough capacity to meet their reliability goals, and without reference to the harm to consumers.[174]

There is some basis for optimism here, however. Now-FERC Chairman Glick dissented from the agency's 2020 order approving PJM's proposed Net CONE, noting that "[t]he last few years have provided mountains of evidence that PJM's Net CONE figure is much too high."[175] Under Chairman Glick's leadership, FERC has reversed some of its previous decisions.[176] Perhaps Chairman Glick can invigorate FERC's review of the RTOs' Net CONE proposals with greater scrutiny.

V. Shape and Slope

Part II and Part III examined the capacity requirement and the Net CONE, both of which are important inputs in creating a capacity market demand curve. The third crucial component of capacity demand is the shape and slope of the demand curve, which determine the quantity of capacity demanded at each price. Despite their importance, however, the shape and slope of capacity market demand curves have received little explanation and justification from RTOs and FERC.

A. Methodology

Price elasticity—that is, the responsiveness of demand to price changes—determines the slope of the demand curve. The more sensitive demand is to price, the flatter the curve. The less sensitive demand is to price, the steeper the demand curve. In organically arising demand curves, each point on the curve represents the marginal value of the good in question to consumers at a certain quantity.[177] Demand curves slope downward—that is, the marginal value decreases as quantity increases—because the benefits to consumption decrease as quantity increases.[178]

In contrast, a fixed capacity requirement in which the amount of capacity does not vary with the price of capacity creates the equivalent of a vertical demand curve.[179] In such a capacity market, the quantity is known, and the market-

174. *See supra* notes 132-134 and accompanying text.

175. *See* Dissenting Statement of Commissioner Richard Glick, PJM Interconnection, L.L.C., 171 FERC ¶ 61,040, P 2 (2020).

176. *See supra* note 97 and accompanying text.

177. See Ian Ayres & John Braithwaite, *Partial-Industry Regulation: A Monopsony Standard for Consumer Protection*, 80 CAL. L. REV. 13, 31 (1992).

178. *See* W.E. Johnson, *The Pure Theory of Utility Curves*, 23 ECON. J. 483, 492 (1913).

179. See Benjamin Hobbs et al., *A Dynamic Analysis of a Demand Curve-Based Capacity Market Proposal: The PJM Reliability Pricing Model*, 22 IEEE TRANSACTIONS ON POWER SYSTEMS 3, 4 (2007).

clearing price will be the bid of the marginal supplier necessary to meet the requisite demand. Early capacity markets tended to use a fixed capacity requirement.[180]

Capacity markets have moved to a downward-sloping demand curve, which offers advantages over a vertical demand curve. First, a sloped curve more accurately reflects the reality that the marginal contribution of a unit to reliability declines as the amount of capacity in the market increases.[181] Second, creating a demand curve in which demand decreases as price increases reduces price volatility and makes it more difficult for suppliers to earn monopoly profits by withholding capacity in the hopes of inflating the market-clearing price.[182] That said, a downward-sloping demand curve is more difficult to create and to administer than a vertical demand curve, as it requires judgements about CONE and the specific shape of the curve. The difference between a downward-sloping demand curve and a vertical demand curve is not as great as it may sound at first; most downward-sloping demand curves for capacity markets have a steep slope centered on the capacity requirement quantity.

Putting each of these factors together, Figure 9 illustrates an example of a demand curve for a capacity market, showing the role of each factor—capacity requirement, Net CONE, and slope—in determining the curve. At capacity levels well below the capacity requirement, demand is constant at a price equal to a multiple of Net CONE—here, 150% of Net CONE. As the quantity approaches the capacity requirement, the curve slopes downward very steeply—but not entirely vertically. At these quantities, demand is highly unresponsive to price—that is, quantity changes only slightly in response to changes in price. The demand price at the capacity requirement is equal to Net CONE. At levels of capacity substantially above the capacity requirement, price is equal to zero, reflecting the very low marginal value of entirely excess capacity.

180. *See* FEDERAL ENERGY REGULATORY COMMISSION STAFF, *supra* note 101, at 5.

181. *See New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 (2003).

182. *See id.*; *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006).

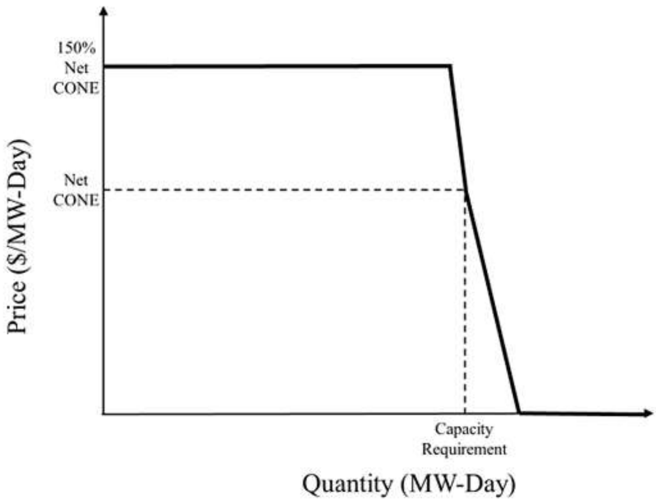

Figure 9: Example of Capacity Market Demand Curve

Downward-sloping demand curves were a key innovation of the Northeast RTOs' second-generation capacity markets, intended to reduce the problems that completely price-insensitive fixed capacity requirements caused in first-generation capacity markets. The specific shapes of the PJM, NYISO, and ISO New England demand curves shared important commonalities as well as differences. Overall, they exhibited a similar shape, with three distinct regions. At quantities from zero to near the capacity requirement, the curves were horizontal at a price fixed to a multiple of Net CONE. At quantities from slightly below the capacity requirement to slightly above it, the demand price decreased steeply. At quantities significantly above the capacity requirement, the demand price was zero.

The horizontal tops of the demand curves essentially set a price cap on the capacity market. The price cap advances a pragmatic objective—to limit price spikes in the event of low supply. For example, in an uncompetitive auction in which all supply resources clear the market without meeting demand, prices could skyrocket without a price cap.[183] The price cap is not, however, rooted in economic theory or evidence of the actual value of capacity. Whereas the price-capped demand curves represent the marginal value of capacity as constant at lower quantities, the actual marginal value of capacity presumably continues to increase significantly as quantities decrease, to values well above the cap. There is no reason to believe that the actual marginal value of capacity is the same at, for example, ninety percent of the capacity requirement, which would be sufficient to meet demand almost every day of the year, as it is at fifty percent, which would likely cause almost daily outages.

183. *See* ISO New England Inc., Demand Curve Changes, FERC Docket No. ER14-1639, at 545-46 (Apr. 1, 2014).

B. *Evaluation*

1. Capacity Demand Curves Differ Arbitrarily.

The RTOs adopted downward-sloping demand curves as an improvement over the vertical demand curves of the first-generation capacity markets.[184] But although the demand curves adopted a downward-sloping shape, the slopes are quite steep, over a relatively narrow range of quantities. Thus, while the downward-sloping curves introduced some price responsiveness, the effect was limited. RTOs were not willing to let the market-clearing quantity fall much below the capacity requirement deemed necessary to meet reliability standards. They also were wary of creating demand for quantities much in excess of the capacity requirement. Overall, these concerns narrowed the range of capacity quantities deemed acceptable, which dictated a steeply sloped demand curve.

Economists measure the sensitivity of demand to price by calculating the relevant arc elasticity of demand.[185] Arc elasticities of less than one are considered inelastic and represent demand for which quantity is relatively insensitive to price.[186] Over the range of quantities on the demand curve where price is responsive to quantity, the arc elasticity of demand for PJM is 0.0375, and for ISO New England it is 0.057. For upstate New York, the arc elasticity of demand is 0.087, while for the flatter New York City curve (see below) the arc elasticity of demand is 0.129. Thus, each of the demand curves used in the second-generation capacity markets are highly inelastic.

While the demand curves of the three Northeast RTOs have their similarities, they also differ substantially. NYISO's demand curve is flatter than PJM's and ISO New England's. PJM's original second-generation demand curve was slightly concave,[187] whereas both NYISO's and ISO New England's were linear. As discussed below, ISO New England has since moved toward creating a convex demand curve based on the marginal impact of capacity on reliability. PJM has adopted a slightly convex demand curve.

In addition, the relationship between the demand curves in capacity-constrained zones and the total demand in the RTOs differs across RTOs. In PJM, each zonal demand curve has the same shape as the system demand

184. *See supra* note 168 and accompanying text; *see also New York Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201 (2003) (explaining the rationale for NYISO's creation of a downward-sloping demand curve); *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006) (explaining the rationale for PJM's creation of a downward-sloping demand curve).

185. *See* R.G.D. Allen & A.P. Lerner, *The Concept of Arc Elasticity of Demand*, 3 REV. ECON. STUD. 226 (1934).

186. Arc elasticity measures the percentage change in quantity as a function of the percentage change in price. This measure is unitless and defined as follows: If P_1 and Q_1 are the price and quantity, respectively, of one point on a demand curve, and P_2 and Q_2 are the price and quantity of another point on the same curve, then the arc elasticity of demand between the two points is $[(Q_2-Q_1)/(Q_1+Q_2)]/[(P_1-P_2)/((P_1+P_2)]$. In the context here, let (P_2,Q_2) be the zero-price point. That implies that P_2 equals zero, the denominator $(P_1-P_2)/((P_1+P_2)$ equals one, and the relevant arc elasticity of demand is $(Q_2-Q_1)/(Q_1+Q_2)$. Arc elasticity is defined similarly for a supply curve. *See* PETER M. SCHWARZ, ENERGY ECONOMICS 64 (2018).

187. A concave demand curve becomes steeper (less price sensitive) as quantity increases; a convex curve becomes flatter (more price sensitive) as quantity increases.

curve.[188] In ISO New England, zonal demand curves and the system demand curve have different shapes, but both are based on the same methodology of analyzing the marginal reliability impacts of capacity.[189] In NYISO, the overall shape of the zonal and system-wide demand curves are similar, but the slopes of the different demand curves are determined through stakeholder negotiation.[190]

2. Capacity Demand Curves Are Not Supported by Economic Theory.

Beyond the general concept of a downward slope consistent with declining marginal benefits of additional capacity, there seems to be no theory supporting the shape of capacity market demand curves. Theoretically a demand curve should represent the marginal benefit to the buyer of the product, which is how much the buyer should be willing to pay at the margin for the product.[191] Because system reliability is a public good, however, electricity consumers are not willing to pay the full value of reliability to them—instead they can free ride off others. This free rider problem could cause reliability to be undersupplied.[192]

System operators nevertheless could approximate the marginal benefit of capacity by estimating the marginal value of additional reliability at different capacity quantities. When ISO New England considered such an approach early in the second-generation capacity markets, however, it rejected it on the ground that the value of reliability (measured in terms of the Value of Lost Load) was too difficult to determine and that the curve might not meet traditional reliability standards.[193]

As an alternative to deriving a demand curve from estimates of the marginal benefit of capacity, the RTOs chose to adopt curves built on the capacity requirement and Net CONE.[194] The premise of the curves was that the long-term equilibrium price and quantity should be close to the additional revenue necessary to attract into the market a plant whose capacity was necessary to meet reliability objectives. Beyond the difficulties of overestimating both the capacity requirement and CONE,[195] this methodology creates two problems. First, it yields only a single point—the intersection of the capacity requirement and Net CONE—and a single point does not create a curve. Second, it is based on cost, rather than benefit, and cost is a factor underlying supply, not demand. Instead of tying their capacity market demand curves to economic theory, the RTOs supported their demand curves by showing that they yielded acceptable results in

188. *See* PJM INTERCONNECTION, L.L.C., *supra* note 33, at 41.

189. *See ISO New England Inc.*, 155 FERC ¶ 61,319 P 6 (2016).

190. *See New York Indep. Sys. Operator, Inc.*, 110 FERC ¶ 61,201 (2005).

191. *See* SCHWARTZ, *supra* note 186, at 40.

192. *See supra* note 34 and accompanying text (discussing reliability as a public good).

193. *See* Spees, Newell & Pfeifenberger, *supra* note 72, at 11; Steven Stoft, ISO New England, Inc., Prepared Direct Testimony on Behalf of ISO New England, FERC Docket No. ER03-563, at 11 (2004). ISO New England subsequently in 2016 adopted a demand curve based on the marginal value of reliability, as described below.

194. *See* Stoft, *supra* note 193, at 10.

195. *See supra* Part II.B.1 and Part III.B.2.

terms of ease of administration, cost, and reliability under a range of likely conditions.[196]

The NYISO zonal and system-wide demand curves illustrate this pragmatic approach. The NYISO linear curves are anchored at two points—the reference point, which is at the capacity requirement for quantity and Net CONE for price, and the zero crossing point, which is at a quantity at which the value of additional capacity has been asserted to be zero.[197] Further, the shape of the demand curves differs across zones within NYISO. Thus, since the beginning of its second-generation market, the zero-crossing point for the upstate zone has been 112 percent of the capacity requirement, while the zero-crossing points for New York City and Long Island have been at 118 percent of the capacity requirement.[198]

There is no indication that the different zero crossing points were based on differences in the marginal value of capacity. Instead of actually attempting to determine the quantity at which the marginal value of capacity reaches zero, the zero crossing points "were established through stakeholder negotiations to balance concerns over price volatility, market power and the relative sizes of marginal generators and owner portfolios as compared to locality size."[199] This process of stakeholder negotiation is vulnerable to decisions to achieve political compromise rather than any economic or analytical justification based on the marginal value of capacity that demand is supposed to represent.

When NYISO consultants subsequently recommended changing the zero crossing point (and therefore the slope) of the capacity market demand curve to better reflect the incremental reliability value of capacity, NYISO rejected the recommendation because a change could "introduce undue volatility and uncertainty into the market."[200] Similarly, when NYISO needed to create a zonal demand curve for the new Lower Hudson Valley zone, rather than taking an analytical approach, it chose a crossing point of 115 percent of the zonal capacity requirement, because that number was midway between two existing zero crossing points for Upstate and New York City zones.[201]

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196. *See* ISO New England Inc., ISO New England Inc., Demand Curve Changes, FERC Docket No. ER14-1639, at 546 (Apr. 1, 2014); *New York Indep. Sys. Operator, Inc.*, New York Independent System Operator, Inc., Filing of Revisions to the ISO Market Administration and Control Area Services Tariff: ICAP Demand Curve, FERC Docket No. ER03-647, at 155-56 (Mar. 21, 2003); PJM Interconnection, L.L.C., PJM Interconnection, L.L.C., Proposal for Reliability Pricing Model, FERC Docket Nos. ER05-1410-000 and EL05-148-000, at 64-69 (Aug. 31, 2005).

197. *See New York Indep. Sys. Operator, Inc.*, 110 FERC ¶ 61,201 (2005).

198. *See, e.g.*, *New York Indep. Sys. Operator, Inc.*, 134 FERC ¶ 61,058 (2011).

199. *See New York Indep. Sys. Operator, Inc.*, 110 FERC ¶ 61,201 (2005).

200. *See New York Indep. Sys. Operator, Inc.*, Proposed Tariff Revisions to Implement Revised ICAP Demand Curves and a New ICAP Demand Curve for Capability Years 2014/2015, 2015/2016 and 2016/2017 and Request for Partial Phase-In And for any Necessary Tariff Waivers, FERC Docket No. ER14-500, at 41 (Nov. 27, 2013).

201. *See* New York Independent System Operator, Inc., New York Independent System Operator, Inc., Proposed Tariff Revisions to Implement Revised ICAP Demand Curves and a New ICAP Demand Curve for Capability Years 2014/2015, 2015/2016 and 2016/2017 and Request for Partial Phase-In and for any Necessary Tariff Waivers, FERC Docket No. ER14-500, at 40 (Nov. 27, 2013).

Since the Northeast RTOs first instituted their sloped demand curves, PJM and ISO New England have changed the shape of their curves. PJM made slight alterations, whereas ISO New England made more significant changes.[202]

PJM changed its demand curve in 2014, extending the horizontal portion of the curve out closer to the capacity requirement and moving from a slightly concave shape to a slightly convex shape.[203] PJM argued that extending the horizontal portion of the curve was necessary to increase reliability. In proposing the change to a convex shape, PJM correctly noted that a convex curve was more consistent with the incremental value of capacity, which should decrease at the margin as quantity increases. Some capacity market buyers opposed the changes, based on their practical consequences—namely that shifting the curve would increase capacity costs unnecessarily and that a convex shape would increase price volatility and the ability to exercise market power in the region of the curve below the capacity requirement.[204] FERC approved a new demand curve, which included a change to a convex shape, on the ground that it would increase reliability at reasonable cost.[205]

ISO New England introduced greater changes to its demand curve for 2019. Acknowledging that its then-existing linear demand curve was "not a function of any specific design principle," ISO New England derived the shape of its new convex demand curve by modeling the marginal increase in reliability from each unit of additional capacity.[206] The resulting curve exhibits clear convexity that reflects the diminishing marginal reliability impact of adding capacity. Once ISO New England determined the shape of the curve through this modeling, it positioned the curve on the price-quantity axes so that the curve intersected the reference point at the capacity requirement quantity and Net CONE price.[207] Due to the convex shape, demand prices were lower at most quantities on the curve, as compared with the prior linear curve.[208] ISO New England retained its existing price cap for capacity quantities well below the capacity requirement. FERC approved ISO New England's new demand curve on the ground that it would meet reliability objectives more cost effectively than its previous curve.[209]

Thus, FERC approved both PJM's and ISO New England's proposed demand curve changes, even though PJM had no apparent underlying theoretical rationale for its proposal whereas ISO New England supported its new curve with a fairly elaborate theory. FERC has not made any attempt in subsequent

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202. NYISO has maintained the same basic shape for its curve, although early in its second-generation market it lowered the horizontal top of its curve to 1.5 times Net CONE (from twice Net CONE). *See New York Independent System Operator, Inc.*, 110 FERC ¶ 61,201 (2005).

203. *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183 (2014). The then-existing curve's horizontal segment ended at 3 percent below the capacity requirement. The new curve's horizontal segment extended to 1 percent below the capacity requirement. *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183 (2014).

204. *See* James F. Wilson, PJM Interconnection, L.L.C., Affidavit in Support of the Protest of PJM Load Group, FERC Docket No. ER14-2940, at 35-39 (2014).

205. *See PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,183 (2014).

206. *See* ISO New England Inc., *supra* note 105, at 2, 6.

207. *See id*. at 7.

208. *See id*. at 710.

209. *See ISO New England Inc.*, 155 FERC ¶ 61,319 P 21 (2016).

years to resolve this discrepancy. Despite approving ISO New England's curve, and therefore implicitly its underlying theory as well, FERC has not indicated to PJM or NYISO that it expects these RTOs to develop an analytical basis for their capacity market demand curves.[210]

Although more rooted in economic principles than the linear second-generation capacity market demand curves, the new convex curves in PJM and ISO New England constitute only a modest improvement over prior curves. PJM's curve is still almost linear and more important, like previous curves, it has a shape that is determined through judgments that are almost entirely opaque and justified only by modeling results comparing the curve to a few other equally arbitrarily chosen options. ISO New England's new curve represents a significant improvement in that it is derived from modeling based on economic theory—rather than just tested with modeling to ascertain the acceptability of its outcomes—but both the modeling itself and the process of translating the model results into a demand curve involve administrative judgments.

In particular, the methodology requires ISO New England to translate the model results, which plot reliability as a function of capacity, to a demand curve that plots the value (price) of capacity against the quantity of capacity. ISO New England readily admits that its translation methodology is not based on an assessment of the marginal value of capacity.[211] The values embedded in the curve cast doubt on how well it reflects the actual value of capacity. ISO New England economists report that the curve implies a value of lost load of \$216,048/MWh.[212] This estimate exceeds other estimations of value of lost load, often by more than an order of magnitude.[213] Although the shape of the ISO New England demand curve has an analytical rationale, the extremely high value of lost load implied by ISO New England's curve calls into question the economic validity of the methodology used to position the curve on the price-quantity axes.

210. This is not to say that the different RTOs must adopt the same analytical basis for their demand curves. Federal Power Act section 205 gives FERC considerable leeway, in judging whether a market rule is just and reasonable, to allow different approaches in different circumstances. *See* Am. Pub. Power Ass'n v. Fed. Power Comm'n, 522 F.2d 142, 146 (D.C. Cir. 1975). But here FERC is not merely allowing different analytical approaches, it is allowing PJM and NYISO to proceed with demand curves that have no apparent underlying economic rationale at all other than their overall downward slope.

211. *See id*. at 702.

212. *See* Feng Zhao, Tongxin Zheng & Eugene Litvinov, *Constructing Demand Curves in Forward Capacity Market*, 33 IEEE TRANSACTIONS ON POWER SYSTEMS 525, 533 (2018).

213. *See id.* at 530 (2018). A value of over \$200,000/MWh for Value of Lost Load is much higher than most estimates. For example, in a report prepared for ERCOT, the Brattle Group assumed an average VOLL of \$9000/MWh, while noting that values can differ considerably across categories of consumers. *See* SAMUEL NEWELL ET AL., ERCOT INVESTMENT INCENTIVES AND RESOURCE ADEQUACY 6, 77 (Brattle Group, June 1, 2012). Another report prepared for ERCOT around the same time stated that the average Value of Lost Load for industrialized countries ranges from \$9000 to \$45,000. *See* JULIA FRAYER, SHEILA KEANE & JIMMY NG, ESTIMATING THE VALUE OF LOST LOAD 9 (London Economics International June 17, 2013). Similarly, the ISO New England External Market Monitor has, in a different context, referred to \$30,000/MWh as "a relatively high value of lost load." DAVID B. PATTON ET AL., 2018 ASSESSMENT OF THE ISO NEW ENGLAND ELECTRICITY MARKETS at ix (Potomac Economics, Ltd. June 2019).

Thus, more than fifteen years after the creation of second-generation capacity markets with downward-sloping demand curves, the origins and basis of the shapes of the curves remain a mystery. The process for creating the shapes is apparently driven more by stakeholder politics and concerns about price volatility than by any sense of whether the curves accurately reflect the value of capacity.

3. Differences in Demand Curve Shapes Affect Market Outcomes.

Differences in demand curve shapes have significant consequences for market outcomes. Figure 10 reports the results of our modeling to illustrate how the different curves used in the Northeast RTOs affect the market-clearing price and quantity. To focus on the shape of the curve, we normalized each curve to the PJM forecast requirement and Net CONE for delivery year 2018-2019. At all quantities greater than the capacity requirement, the ISO New England curve has lower prices than either upstate New York or New York City. The ISO New England curve also yields lower prices than the PJM curve, until quantity reaches about 107 percent of the capacity requirement. The PJM curve results in lower prices than either of the New York state demand curves when the quantity is greater than about 102 percent of the capacity requirement. As long as the quantity is greater than the capacity requirement, New York City prices are higher than upstate New York prices.

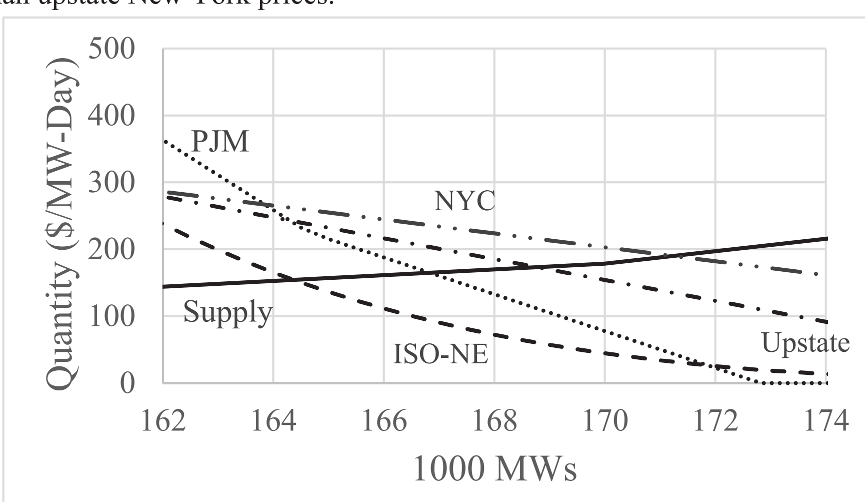

Figure 10: Market Results with Different Demand Curves

Table 1 reports the results of the modeling, employing the supply curve for PJM used above. Using the ISO New England curve results in the lowest price, slightly over $154/MW-day. The New York City curve results in the highest price, $190. Capacity revenues for one year under the New York City curve are $2.6 billion more than under the ISO New England demand curve.

Demand Shape	ISO-NE	PJM	Upstate New York	New York City
Quantity (1000 MW)	164.37	166.83	168.77	171.239
Price ($/MW-day)	$154.29	$164.88	$173.22	$190.02
Revenue ($ billion)	$9.26	$10.04	$10.67	$11.88

Table 1: Market Outcomes with Different Demand Shapes

Each RTO has developed its own demand curve, through its own administrative process, with at most limited investigation of what makes an optimal shape for a capacity market demand curve. Despite the difference in the curves, which can result in large differences in capacity revenues collected, and the scarcity of underlying theoretical justifications, FERC has deemed each of these demand functions 'just and reasonable.' There appears to be little consistency in FERC's rulings on these matters, other than deferential support for the RTOs' proposals.

VI. CONCLUSION

Capacity market demand curves derive from three factors: the capacity requirement, the Net CONE, and the shape of the demand curve. Each factor presents serious challenges for the RTOs and FERC. PJM and ISO New England have systematically overestimated peak demand for their capacity markets, which in turn inflates their capacity requirements. PJM, NYISO, and ISO New England all have overestimated Net CONE for their markets. Finally, the shapes of the demand curves are based on potentially arbitrary political compromises among stakeholders rather than economic valuations of capacity.

Justifications of administratively determined capacity market demand are quite thin. There appears to be little or no reason to believe that capacity market demand reflects the actual value of capacity. Existing methods for forecasting peak demand, estimating Net CONE, and setting the shape of demand curves require numerous administrative judgments on which there is little guidance or analytical clarity. Yet each of these decisions can have substantial consequences. The bias toward higher quantities and prices increases revenues to generators and costs to consumers. FERC, which must review and approve RTO decisions that determine demand, has largely abandoned its role, conducting its reviews with great deference to the RTO stakeholder-based process instead of identifying a coherent standard and then evaluating proposals based on whether they comport with the standard. As a result, demand in capacity markets depends more on the vagaries of RTO stakeholder politics than on market forces or theoretically grounded design principles.

Capacity market demand thus replicates many of the pathologies of traditional utility regulation through cost-of-service ratemaking. Demand in capacity markets is created through complex administrative processes assembled through an array of opaque decisions that involve discretionary judgments. These administrative processes resemble the decision-making processes used in traditional public utility regulation and, like those processes, yield statistically biased results that are not consistent with competitive market outcomes. This is ironic, because the electricity restructuring movement that birthed capacity markets arose as a rejection of traditional utility regulation in favor of competitive markets. Scrutiny reveals that capacity market demand shares far more with cost-of-service ratemaking than one would expect from a competitive market.

These problems could be alleviated, at least in part, with fixes to the administrative processes. Reducing the time between a market auction and the relevant delivery year could improve the accuracy of forecasting. An empirical Net CONE could reduce bias in administrative estimations. A modeled demand curve shape, like ISO New England's, together with a more reasonable value of lost load could more accurately represent the marginal value of capacity in the shape of demand curves.

Although FERC has to date addressed issues of capacity market demand in individualized adjudicatory decisions, the critiques raised in this article suggest that a more systematic approach is warranted. FERC has broad discretion under Federal Power Act section 205 to proceed by either adjudication or rulemaking.[214] A rulemaking process in which various stakeholders are able to propose methodologies for setting capacity market demand, with an accompanying justification rooted in economic analysis and sound empirical footing, could significantly reduce the costly errors of the current process that lead to excessive purchases in capacity markets. Rulemakings are time and resource intensive and should not be undertaken lightly. But the stakes here—billions of dollars of excessive costs imposed on electricity customers—are sufficient to justify a considerable investment by the agency.

Yet even a comprehensive rulemaking might not suffice. The administrative apparatuses employed by the RTOs and approved by FERC exhibit a strong bias toward conservatively protecting reliability in ways that inflate capacity market prices. The process allows for stakeholders to protect their vested interests. Modifications that operate within the system are unlikely to change the system fundamentally, and it is unclear that anything less than fundamental change can bring real improvement that would make capacity market demand look more like a real market.

214. *See* Towns of Concord, Norwood & Wellesley, Mass. v. FERC, 729 F.2d 824, 830 (D.C. Cir. 1984).

HOW DOES RESTRUCTURING OF ELECTRICITY GENERATION AFFECT RENEWABLE POWER?

Shelley He, Eric Biber, Helen Aki, Maribeth Hunsinger, and Stephanie Phillips[*]

Synopsis: As states and the federal government seek to advance renewable energy deployment, one possible policy tool is restructuring of electricity generation regulation in order to increase competition. There have been a wide range of generation restructuring measures at both the state and federal level in the electric power sector since the 1990s. In this Article, we compile a comprehensive dataset of different types of generation restructuring policies, including divestiture, procurement, siting, and interconnection requirements at the state level as well as the establishment of regional grid governance entities. Leveraging variation in timing of state-level policy adoption, creation and roll-out of regional grid governance entities, we show that restructuring efforts on divestiture and siting overall matter a lot. While the absolute magnitude of the changes from these policies appears small (increasing renewable electricity capacity by 1.7-2.5%), they represent very large – and statistically significant – increases from the low baseline level of renewable capacity in our measured time period. For instance, changes to state regulations for siting generation facilities increase renewable energy capacity levels in a state by 50%. Development of regional transmission organizations and independent system operators have had smaller positive direct impacts, and amplifies the effects of other renewable policies. By contrast, we

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find little impacts for generation restructuring related to interconnection and procurement, and we find little impact of public versus private ownership in determining renewable investment. Our results show that some forms of generation markets can advance renewable energy development, but that the public versus private status of a utility system is unlikely to be a key driver of outcomes.

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I. INTRODUCTION

Many state governments have set ambitious goals for renewable energy deployment in the next twenty years. California has set a goal of 60% renewable electricity by 2030, with all electricity being carbon-free by 2045.[1] New York has set an even more ambitious goal of 70% renewable electricity by 2030 and 100% carbon-free electricity by 2040.[2] To achieve these goals, both the states and the federal government have drawn on a range of policy tools: renewable portfolio standards (RPS), regional management of electricity grids, tax credits, and feed-in tariffs. But while many states have embraced these policy tools, other states have stalled in their progress and either failed to enact more robust RPS, or have even rolled back renewable policies.[3] And proposals for federal clean energy standards have to date, been controversial and consistently fallen short.

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1. See Cal. Pub. Utility Code Section 399.11(a); *id.* Section 454.53.

2. See NY Senate Bill S6599 (2019).

3. For instance, Texas has never updated its RPS that set a goal of 10,000 MW of renewable energy capacity by 2025, a standard it has long since surpassed. *See* DSIRE, *Renewable Generation Requirement* (last updated June 26, 2018), https://programs.dsireusa.org/system/program/detail/182. Ohio repealed its RPS mandate effective in 2026. *See* Ohio House Bill 6 (2019).

Policymakers seek to advance renewable energy because it can decarbonize the electricity sector, a critical component of climate policy given that approximately 30% of global emissions originate from electric power generation.[4] Renewable energy policy is thus intertwined with electricity policy more broadly. In this Article, we explore a broader range of electricity policies to advance renewable energy beyond the standard renewable policies, such as RPS. A wider range of options could promote renewable energy even in jurisdictions that are politically hostile to efforts to address climate change or skeptical of policy tools such as RPS that are often identified with environmentalism.

In particular, American electricity policy has been the subject of dramatic changes to open up the electricity sector to greater competition, a process that is often called restructuring. In this Article, we distinguish between two forms of restructuring: policy changes that focus on the ability of consumers to select their retail electricity provider (retail restructuring), and policy changes that focus on increasing the entry of new entities into the generation of electricity.[5] Both retail and generation restructuring began in earnest in the United States in the 1990s, as both the federal government and state governments moved to eliminate monopoly ownership of electricity generation assets, create competition in the wholesale electricity sector, and develop choice of suppliers in wholesale markets in order to increase efficiencies and lower costs to consumers.[6] In so doing, they encouraged states to restructure and create retail choice for consumers.[7] Similar transitions have occurred in Europe, Latin America, and other countries around the world.[8]

That transition has come with uncertain and debated impacts for environmental and climate policy, including concerns that this shift would undercut efforts to reduce emissions from the electric power sector.[9] While prior

4. *See* CTR. FOR CLIMATE & ENERGY SOLUTIONS, ENERGY/EMISSIONS DATA: GLOBAL EMISSIONS, https://www.c2es.org/content/international-emissions (last visited May 29, 2020). Indeed, researchers and policymakers increasingly advocate electrifying additional sectors of economy, such as transportation, arguing that would facilitate broader decarbonization of the economy.

5. In particular, within the concept of generation restructuring we include efforts to reduce barriers to new construction of generation facilities, requirements for utilities to divest generation facilities, and federal and state reforms to wholesale markets and transmission systems to facilitate the sale of electricity by non-incumbent utilities. Within the concept of retail restructuring, we include unbundling of retail services such as delivery, metering, and billing, and the separation of the distribution of electricity from the sale of electricity; both of these can facilitate the provision of retail sales and services by a range of competing providers.

6. FEDERAL/STATE JURISDICTIONAL SPLIT: IMPLICATIONS FOR EMERGING ELECTRICITY TECHNOLOGIES (2016), https://www.energy.gov/sites/prod/files/2017/01/f34/Federal%20State%20Jurisdictional%20Split--Implications%20for%20Emerging%20Electricity%20Technologies.pdf.

7. *See* JOEL EISEN, EMILY HAMMOND, JIM ROSSI, DAVID SPENCE, & HANNAH WISEMAN, ENERGY, ECONOMICS, AND THE ENVIRONMENT: CASES AND MATERIALS, Ch.10 (4th ed. 2015).

8. *See, e.g.,* Ergan Erdogdu, *What happened to efficiency in electricity industries after reforms?*, 39 ENERGY POLICY 6551 (2011) (providing overview of global transition to restructuring).

9. *See* Ryan Wiser, Steven Pickle, & Charles Goldman, *Renewable Energy Policy and Electricity Restructuring: A California Case Study*, 26 ENERGY POL'Y 465, 465-66 (1998) (arguing that that restructuring might undermine renewable energy investment, but also noting possible countervailing factors); James Dooley, *Unintended Consequences: Energy R&D in A Deregulated Energy Market*, 26 ENERGY POL'Y 547-55 (1998) (noting the risk that restructuring might both disadvantage higher cost renewables, and reduce investment in research and development for more environmentally sustainable energy generation technologies); Navroz Dubash, *The Public Benefits Agenda in Power Sector Reform*, 5 ENERGY FOR SUSTAINABLE DEV. 5 (2001) (noting varying arguments about how restructuring may advance or harm reducing emissions from electricity industry); V. Balu, *Issues and Challenges Concerning Privatization and Regulation in the Power Sector*, 3

research has focused on restructuring as a possible threat to environmental and climate goals,[10] this Article explores the possibility that restructuring could be a positive step towards advancing climate goals. Restructuring is generally framed as an effort to reduce barriers to entry to new business entities and technologies in electricity – and renewable energy is a new technology that may be advanced by new business entities.[11] Restructuring therefore might produce policies that enable entry by renewable energy technologies and companies to enter the market and establish themselves.

In general, prior research exploring the interaction of restructuring and environmental impacts has focused on retail-side restructuring, whether end-use consumers can choose between multiple electricity providers or are limited to only one.[12] The most recent study of the relationship between retail restructuring and renewable energy policy and generation found no relationship,[13] but earlier works found differing impacts.[14]

ENERGY FOR SUSTAINABLE DEV. 6, 8 (1997) (noting that restructuring might reduce energy efficiency and renewable investments); Michael Heiman & Barry Solomon, *Power to the People: Electric Utility Restructuring and the Commitment to Renewable Energy*, 94 ANNALS OF THE ASS'N OF AM. GEOGRAPHERS 94, 94-95, 103-04 (2008) (arguing that renewables may not be able to compete in restructured markets); Joel Swisher & Maria McAlpin, *Environmental Impact of Electricity Deregulation*, 31 ENERGY 1067 (2005) (noting a range of ways in which restructuring may advance or retard environmental progress in the electricity sector); Karen Palmer & Dallas Burtraw, *The Environmental Impacts of Electricity Restructuring: Looking Back and Looking Forward*, 1 ENV'T & ENERGY LAW & POL'Y J. 171 (2006) (noting mixed predictions of impacts of restructuring on environmental outcomes, and difficulty of separating out the impacts of restructuring from other changes in the electricity industry).

10. *See infra*, note 13.

11. FEDERAL/STATE JURISDICTIONAL SPLIT: IMPLICATIONS FOR EMERGING ELECTRICITY TECHNOLOGIES (2016), https://www.energy.gov/sites/prod/files/2017/01/f34/Federal%20State%20Jurisdictional%20Split--Implications%20for%20Emerging%20Electricity%20Technologies.pdf.

12. For research focused on retail restructuring, *see* Sung Eun Kim, Joonseok Yang, & Johannes Urpelainen, *Does Power Sector Deregulation Promote or Discourage Renewable Energy Policy? Evidence from the States, 1991-2012*, 33 REV. OF POL'Y RSCH. 22, 23-24 (2016); Thomas Lyon & Haitao Yin, *Why Do States Adopt Renewable Portfolio Standards?: An Empirical Investigation*, 31 THE ENERGY J. 133, 150-51 (2010); Magali Delmas & Maria Montes-Sancho, *U.S. State Policies for Renewable Energy: Context and Effectiveness*, 39 ENERGY POL'Y 39:2273, 2278, 2281 (2011); Joel Swisher & Maria McAlpin, *supra* note 9, at 1067 (including wholesale restructuring as part of analysis of state renewable energy generation, but not separating that out from retail restructuring in the analysis). The exception is Andrew Prag, Dirk Röttgers, & Ivo Scherrer, *State-Owned Enterprises and the Low-Carbon Transition* (OECD Environment, Working Papers No. 129, 2018), who studied how investment in renewable energy varies across OECD member states and other large national economies based on the degree of market concentration in the electricity sector, the requirement for vertical separation between generation and transmission/distribution, and the ease of entry into the electricity market for third parties. This article differs from our study in two important ways. First, they focus at the national level, while we focus at the state level in the United States – allowing for a comparison as to whether dynamics vary at the subnational versus national level. Second, they primarily use proxies for measures of the regulatory framework for vertical separation and ease of entry for third parties, though they do directly code for that framework for a limited number of countries, while we code for that data directly for US states, providing a more accurate assessment of the regulatory system. They also appeared to have coded at the national level for these variables for the United States, but as discussed below, most of these policies are determined in a significant way at the state level.

13. Kim, Yang, Urpelainen, *supra* note 12, at 23-24 (finding that retail restructuring did not have a clear relationship with renewable energy capacity, but did have a positive correlation with state adoption of policy supporting renewable energy).

14. Andrew Prag, Dirk Röttgers, & Ivo Scherrer, *supra* note 12 (finding no relationship between renewable energy investment and either separation of generation from transmission/distribution or increased access of third parties to the electricity market); Thomas Lyon & Haitao Yin, *supra* note 12, at 150-51 (finding that states with

However, retail restructuring on its own does not drive significant investments in the electricity industry. Retail electricity sales are a combination of the sale of electricity and the provision of customers services such as billing.[15] In contrast, generation restructuring involves divestiture of generation assets from incumbent utilities or increasing the ability of non-incumbent utilities to construct new generation facilities.[16] To the extent retail restructuring can drive any major investments—particularly investments in generation technology—it must be in parallel with restructuring in the generation sector, where new entrants, existing producers or customers, and even electric utilities can build new facilities or repurpose existing facilities. For instance, if end-use consumers exercise their new-found retail choice in favor of 100 % renewable energy options, the impact of such choices on increasing renewable generation will be much larger to the extent that those retail customers (and the retail providers that serve them) can choose from competing generators, who in turn have competitive incentives to make investments in renewable energy to serve those customers' demand.[17]

Indeed, the efficiency benefits of retail restructuring are difficult to achieve without some form of generation restructuring, since without generation restructuring the competing retail providers would still be buying power from the same monopoly electricity generator.[18] On the other hand, many US states have moved towards some form of generation restructuring without retail restructuring, believing that generation restructuring can reduce costs that then can be passed onto consumers through the retail regulatory process.[19]

Accordingly, in this Article we focus on the generation side of restructuring, and its relationship with renewable energy production in the United States. Relevant policies for generation restructuring include state and federal efforts to deconstruct the monopoly of utilities in electricity generation and wholesale markets; state policies that facilitate competition in the procurement of power by regulated utilities; and state policies that reduce or eliminate the barriers to entry for new generation, specifically elimination of or changes to state restrictions on siting of generation facilities and changes to requirements for interconnection of new facilities to the grid. While only some of these policies have been generally

restructured retail electricity markets are more likely to have renewable energy policies); Magali Delmas & Maria Montes-Sancho, *supra* note 12, at 2278, 2281 (finding a negative correlation between deregulation and renewable energy production); Swisher and McAlpin, *supra* note 9, at 1075 (finding that restructured states without other programs to support renewable energy had higher levels of generation from renewable energy than fully regulated states, but finding an opposite relationship for states that also had renewable energy support programs such as renewable energy portfolio standards).

15. US Electricity Markets 101: An overview of the different types of US electricity markets, how they are regulated, and implications for the future given ongoing changes in the electricity sector at 2 (March 3, 2020), https://www.rff.org/publications/explainers/us-electricity-markets-101/.

16. *Id.* at 2, 4.

17. *Id.* at 6, 11.

18. *See* Kim, Yang, & Urpelainen, *supra* note 12 ("The defining feature of [restructuring electricity markets] is the introduction of competition among power generators. Retail customers are now allowed to select their own suppliers, with the idea that competitive pressure reduces retail prices.").

19. US Electricity Markets 101: An overview of the different types of US electricity markets, how they are regulated, and implications for the future given ongoing changes in the electricity sector at 2, 5 (March 3, 2020), https://www.rff.org/publications/explainers/us-electricity-markets-101/.

associated with the restructuring of electricity generation in the United States, all have the effect of facilitating competition and new investments in the generation sector. For ease of reference, we collectively refer to these policies as "generation restructuring" in this Article.[20]

Restructuring policies may do more than advance renewable energy deployment in the short-term. They may also advance climate policy more broadly in the long-term, by increasing political support overall for climate policy. The political challenges of decarbonizing national economies quickly enough to avoid warming greater than the 2 degrees Celsius target set by the Paris Accord are daunting.[21] The primary policy approach recommended by most economists and scientists to achieve that goal, carbon pricing, is often politically infeasible.[22] Proposals for carbon pricing have been rejected at both the state and national level recently in the United States,[23] and where carbon prices have been enacted, they generally have been preceded by other policy tools such as regulation, subsidies, or other forms of "green industrial policy."[24]

A major obstacle to the enactment of carbon pricing—and indeed, any enactment of more aggressive climate policy—has been the powerful economic and political interests arrayed in opposition.[25] Carbon pricing, and climate policy more generally, requires overcoming opposition from interests as diverse as the fossil fuel extraction industry, the automobile sector, the electricity sector, and more.[26] In addition, climate policy generally requires voters in democracies be willing to pay a price today for benefits in the future—a tall order given the myopia of voters and short-term electoral pressures.[27]

Where climate policy has achieved some success, such as in California and the European Union, there is evidence that it has worked because initial policies

20. We study variation in generation restructuring across states in the United States for two reasons. First, analysis of variation across US states has been a focus for prior research on the interaction between electricity restructuring and environmental outcomes. *See* Kim, Yang, & Urpelainen, *supra* note 12; Lyon & Yin, *supra* note 12, at 150-51 (finding that states with restructured retail electricity markets are more likely to have renewable energy policies; Delmas & Montes-Sancho, *supra* note 12, at 2278, 2281 (finding a negative correlation between deregulation and renewable energy). Second, the substantial variation across states in terms of electricity policy and the relatively large number of state units (50) within a well-integrated federal system and national economy allows for tractable econometric analysis.

21. United Nations Framework Convention on Climate Change, Paris Agreement, Dec. 12, 2015, T.I.A.S. No. 16-1104. http://unfccc.int/files/meetings/paris_nov_2015/application/pdf/paris_agreement_english_.pdf.

22. INT'L MONETARY FUND, FISCAL AFFAIRS DEP'T, FISCAL MONITOR: HOW TO MITIGATE CLIMATE CHANGE (2019), https://www.imf.org/en/Publications/FM/Issues/2019/09/12/fiscal-monitor-october-2019.

23. *See, e.g.*, Damien Cave, *It Was Supposed to Be Australia's Climate Change Election. What Happened?* N.Y. TIMES (May 19, 2019), https://www.nytimes.com/2019/05/19/world/australia/election-climate-change.html; Kate Schmiel, *What Killed Washington's Carbon Tax?* HIGH COUNTRY NEWS (January 21, 2019), https://www.hcn.org/issues/51.1/energy-and-industry-what-killed-washingtons-carbon-tax.

24. *See* Jonas Meckling, et al., Winning Coalitions for Climate Policy, 349 SCI. 1170 (2015).

25. *See* DANNY CULLENWARD & DAVID VICTOR, MAKING CLIMATE POLICY WORK 9-10 (2020).

26. *See* Meckling, *et al.*, *supra* note 24; Eric Biber, Nina Kelsey, & Jonas Meckling, *The Political Economy of Decarbonization: A Research Agenda*, 82 BROOKLYN L. REV. 605 (2017) [hereinafter *A Research Agenda*]; CULLENWARD & VICTOR, supra note 25, at 9-10.

27. *See* RICHARD LAZARUS, THE MAKING OF ENVIRONMENTAL LAW 41 (2004). ("Those seeking elected office tend to stress the importance of economic growth and promise short-term results."); *id.* at 223-24 ("Much environmental protection depends on short-term sacrifices for what can be very speculative long-term gains."); *see also* Eric Biber, *Climate Change and Backlash*, 17 N.Y.U. ENV'T L.J. 1295, 1320-21 (2009).

built up interest group support for subsequent climate policy.[28] Understanding the "political economy of decarbonization" is therefore central to addressing the severe climate changes forecast by many scientists.[29] But not all policy that drives the political economy of decarbonization will be explicitly climate policy, and indeed a range of other policies and laws may affect the development and growth of the interest groups relevant for climate policy.

Deregulation and restructuring of the electricity generation sector can be an important policy tool shaping the broader political economy of climate policy if it drives investment and development of renewable energy production. And since investments by interest groups are a major driver of changes in political economy,[30] understanding how electricity policy might shift the political economy of decarbonization requires focusing on the policies that shape those investments. As noted above, generation restructuring may be more important in driving investment than retail restructuring.[31] A key question for understanding the political economy of decarbonization is who owns renewable energy projects, which in turn determines which actors have an incentive to push for greater decarbonization policies. Research is ambiguous as to whether ownership of electricity generation by governments (which can be seen as a stronger version of political control over the electricity sector than regulation of private utilities) is correlated with greater renewable energy investment or adoption of renewable energy policies,[32] or whether restructuring of the electricity sector allows for greater development of independent power producers in the renewable sector.[33]

Recent trends highlight the potential importance of who owns renewable energy. As we can see from Figure 1, between 1990 and 2018, the composition of generation capacity ownership among renewable power producers changed substantially, with more than 70 percent of renewable capacity owned by independent power producers (IPP) and close to zero percent by public entities in

28. *See* Eric Biber, *Cultivating A Green Political Landscape: Lessons for Climate Change Policy from the Defeat of California's Proposition 23*, 66 VAND. L. REV. 399 (2013); Meckling, et al., supra note 27.

29. *See* Biber, Kelsey & Meckling, *supra* note 26.

30. *See* Biber, *Cultivating A Green Political Landscape*, supra note 28.

31. We do note that prospectively, new technologies and business models such as demand response, distributed generation and storage technologies, and electric vehicles that are integrated with the grid may change this dynamic, where control over retail and distribution services may drive substantial investments and have substantial impacts on renewable energy. However, these are still nascent developments.

32. *Compare* Delmas and Montes-Sancho, *supra* note 12, at 2278, 2281. (finding that private, investor-owned utilities are more responsive to renewable portfolio standards) *with* Dirk Röttgers & Brile Anderson, *Power Struggle: Decarbonising the Electricity Sector* 29, 33 (OECD Environment ,Working Papers No. 129, 2018) and Prag, Röttgers, & Scherrer, *supra* note 12 (finding that increased public ownership of electricity sector correlates positively with increased investment in renewable energy); *see also* Leah Stokes, *The Politics of Renewable Energy Policies: The Case of Feed-in Tariffs in Ontario, Canada*, 56 ENERGY POL'Y 490, 492-94 (2013) (describing case study of Ontario finding a leadership role for the publicly owned utility in advancing feed-in-tariffs that support renewables); Heiman & Solomon, *supra* note 9, at 107-08 (arguing that public power systems will be more amenable to encouraging renewable development).

33. *See* Nina Kelsey & Jonas Meckling, *Who wins in renewable energy? Evidence from Europe and the United States*, 37 ENERGY RSCH. AND SOC. SCI. 65, 69-70 (2018) (finding no clear evidence that restructuring status advantages either incumbent utilities or independent power producers in renewable energy investment).

2018.[34] In contrast, the composition of ownership among non-renewable power producers remained largely unchanged.[35] There is also tremendous heterogeneity across states, as shown in Figure 2. For example, in Delaware and Illinois, renewable and nonrenewable generation capacity have almost identical ownership structures, while in other states the ownership structures generally differ.[36] Interestingly, even in states where the generation system is dominated by public ownership, such as Nebraska, Tennessee and North Dakota, most renewable generation capacity is instead owned by private entities, including IPPs.[37]

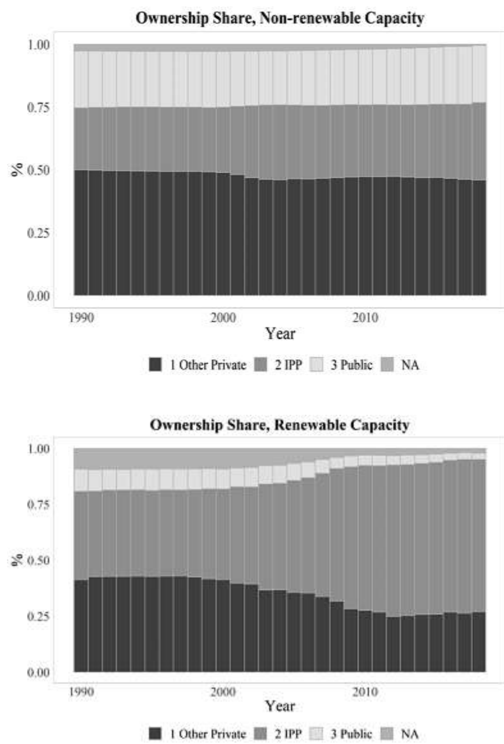

Figure 1: Share of Capacity of Different Ownership, By Energy Source (Non-Renewable Vs. Renewable), 1990-2018

34. IPP refers to independent power producers, which are non-utility owners of generation capacity. Public capacity refers to assets owned by rural cooperatives and municipal utilities.

35. U.S. Energy Information Administration, *Renewables Account for Most New U.S. Electricity Generating Capacity in 2021* (January 11, 2021), https://www.eia.gov/todayinenergy/detail.php?id=4616.

36. U.S. Energy Information Administration, *Illinois State Profile and Energy Estimates* (June 17, 2021), https://www.eia.gov/state/analysis.php?sid=IL; U.S. Energy Information Administration, *Delaware State Profile and Energy Estimates* (October 21, 2021), https://www.eia.gov/state/analysis.php?sid=DE.

37. Feldman, David, Mark Bolinger, and Paul Schwabe, *Current and Future Costs of Renewable Energy Project Finance Across Technologies*. Golden, CO: National Renewable Energy Laboratory (2020), https://www.nrel.gov/docs/fy20osti/76881.pdf.

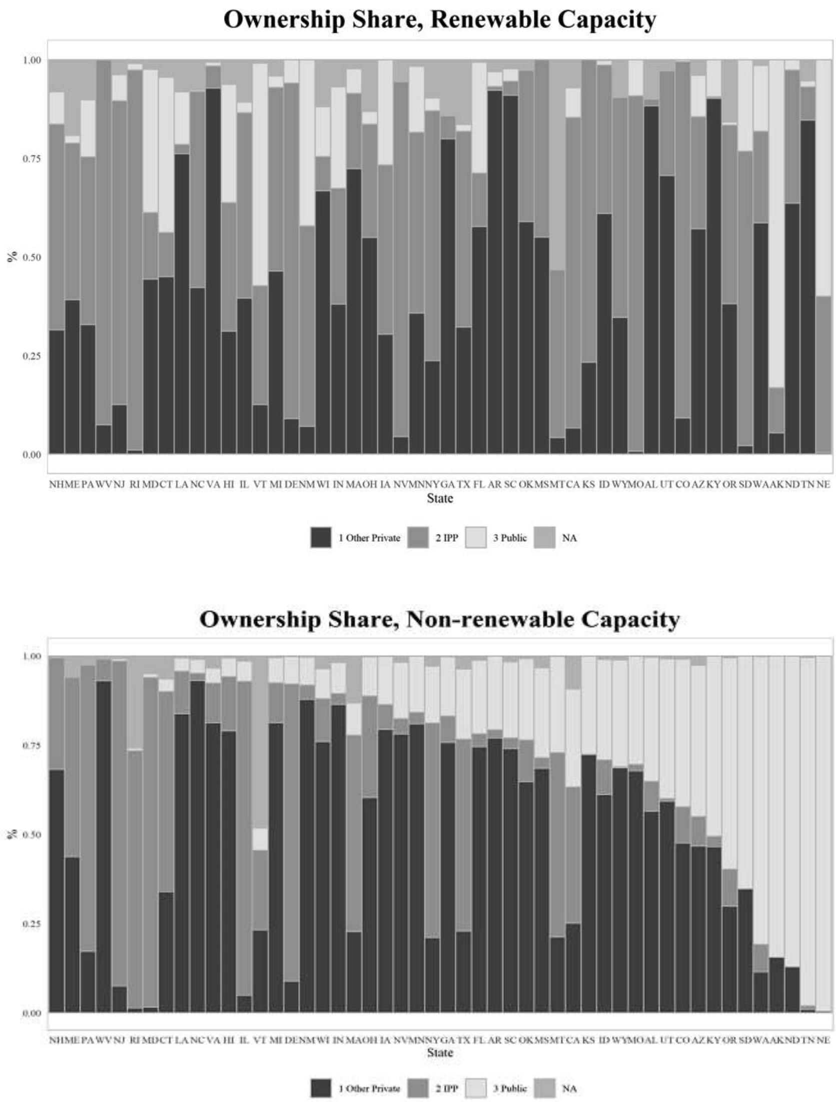

Figure 2: Average Share of Capacity of Different Ownership, By Energy Source (Non-Renewable Vs. Renewable), 50 States

The question of whether public or private ownership of electricity assets will advance greater renewable energy deployment has relevance to current domestic policy debates in the United States about whether a "Green New Deal" that emphasizes government investment and control over electricity can accelerate decarbonization. And internationally, countries such as Mexico have wrestled with whether nationalization of electricity systems will hinder decarbonization efforts.[38]

In this article, we quantitatively assess these questions about the relationships between generation restructuring, electricity ownership, and renewable energy deployment, with the goal of informing both immediate policy debates and broader political economy research. Specifically, we collect data on state-level generation-side restructuring efforts in the United States from 1990 to 2018, and assess its relationship with the proportion of a state's electricity capacity that is attributable to renewable sources.

In Part II we provide some additional legal background that explains which aspects of state-level restructuring policy we assess, and why those policies are relevant to renewable energy deployment. In Part III we summarize the results from our analysis. In Part IV, we connect our results to the initial policy and political economy questions set forth in this Article.[39]

II. LEGAL BACKGROUND

The legal landscape for generation restructuring in the United States is more complex than retail restructuring because of the division of jurisdiction between federal and state governments, and the range of relevant state policies. In general, retail side restructuring – providing consumer choice for service providers – is an issue exclusively reserved to states under the Federal Power Act.[40] While there is some variation among the states that have undertaken retail restructuring in terms of the details, it is relatively easy to identify states as falling into one of two categories: either those that have adopted, or rejected, retail restructuring. There has been little change in the status of retail restructuring at the state level since the California electricity crisis of 2001, with no additional adoption of restructuring by states, and some states (e.g., California) rolling back or freezing tentative steps towards restructuring.[41]

However, state generation-side restructuring involves a wider range of policy options adopted by different states at different times, a larger number of states making at least partial moves towards generation restructuring, and a longer period of time over which changes have occurred. In general, policy options for restructuring in the generation context focus on reducing regulatory obstacles to new entrants in the generation sector, reducing the ability of incumbent utilities to discriminate against competing generators through control of transmission

38. *See* Kirk Semple and Oscar Lopez, *Mexico Set to Reshape Power Sector to Favor the State*, N.Y. TIMES, March 7, 2021, https://www.nytimes.com/2021/03/07/world/americas/mexico-energy-sector-privatization.html.

39. We also provide two appendices. Appendix A provides a detailed overview of the history of federal efforts to restructuring electricity in the United States as background for readers who are not expert in American energy law. Appendix B provides the details of our methodology of our analysis and data collection.

40. The Federal Power Act limits federal regulation to "the sale of electric energy at wholesale in interstate commerce" but leaving to state jurisdiction "any other sale of electric energy" 16 U.S.C. § 824(b).

41. *See* Kim, Yang, & Urpelainen, *supra* note 12, at 26; Heiman & Solomon, *supra* note 9, at 99.

systems, and creating transparent and open wholesale markets to facilitate deal-making between new entrants and existing actors.[42]

Regulation of siting and other facets of the electricity generation and regulation of the wholesale electricity market are split between states and the federal government.[43] The Federal Power Act gives the federal government – through the Federal Energy Regulatory Commission (FERC) – the power to regulate transmission and wholesale sales of electricity in interstate commerce.[44] In general states have control over the approval of siting of new generation facilities, and, for vertically-integrated utilities that own generation and transmission, the ability to control the extent to which regulated utilities can pass the costs of generation on to consumers.[45] The federal government has driven much of the movement towards restructuring in generation markets through both legislation and regulatory action, beginning in the late 1970s.[46] Most important, for our purposes, are federal efforts to encourage regional governance of transmission systems, and transfer of management of transmission systems away from utilities to either regional transmission organizations (RTOs) or independent system operators (ISOs). Through Orders 888 and 2000, FERC encouraged creation of RTOs and ISOs, which also oversee competitive wholesale markets for electricity.[47] Today, about two-thirds of the country receives electricity from RTO or ISO governed grids, and RTOs and ISOs are a critical component of generation

42. FTC, Staff Report: Competition and Consumer Protection Perspectives on Electric Power Regulatory Reform, 20580 (July 2000).

43. The Federal Power Act provides for federal jurisdiction over "the transmission of electric energy in interstate commerce and to the sale of electric energy at wholesale in interstate commerce" but reserving for state jurisdiction "any other sale of electric energy," as well as jurisdiction "over facilities used for generation of electric energy" 16 U.S.C. § 824(b)(1).

44. The Supreme Court has broadly interpreted the definition of interstate commerce to apply to any segment of an electricity grid that has interstate interconnections. *See* FPC v. Florida Power & Light Co., 404 US 453, 453 (1972). Thus, the only states for which broad federal regulatory control over wholesale markets does not exist are states whose electricity grid is not interconnected across state lines – Alaska and Hawaii. In addition, a provision of federal law exempts most of Texas from FERC jurisdiction so long as the connections between Texas and the rest of the United States are direct current transmission lines.

45. US Electricity Markets 101: An overview of the different types of US electricity markets, how they are regulated, and implications for the future given ongoing changes in the electricity sector at 2 (March 3, 2020), https://www.rff.org/publications/explainers/us-electricity-markets-101/.

46. Historically, federal wholesale regulatory power in the United States was relatively limited in practice because most electricity generation was controlled by vertically-integrated monopoly electricity utilities that produced electricity at their own generating facilities, transmitted and distributed that electricity over lines they owned and controlled, and then sold it at retail to end-user customers. The only transaction subject to regulation that would occur for this electricity was the retail sale, which fell within state regulatory power. The federal government has made it a priority since the late 1970s to increase the size and importance of wholesale electricity markets as part of its overall efforts to advance electricity restructuring, including deregulation of electricity generation in the United States. These changes have effectively expanded the potential scope of federal power. We provide a full overview of this history for readers who are not energy lawyers in Appendix A.

47. TRANSMISSIVES, *Restructuring: The Effects of FERC Orders 888, 889, and 2000*, https://transmissives.com/the-story-of-the-grid/restructuring-the-effects-of-ferc-orders-888-889-and-2000/#:~:text=Orders%20888%2C%20889%2C%202000%2C,and%20the%20Southwestern%20Power%20Pool.

restructuring because they allow for independent power producers to access transmission and wholesale markets independent of incumbent utilities.[48]

Paralleling the movement towards generation restructuring at the federal level, many (but not all) states also exercised regulatory authority to restructure the electricity generation sector and to increase competition.[49] As a result, a number of states have moved away from the traditional U.S. model of vertically-integrated, highly regulated monopoly electric utilities in order to encourage competition, removing potential obstructions to generation technology innovation and market efficiency.[50] Early advocates of electricity restructuring argued that it would increase the economic efficiency of energy production and consumption, and market liberalization initiatives emerged in many states during the late 1990s and early 2000s.[51] However, the momentum for such initiatives has now largely evaporated, and some states have even rolled back existing restructuring policies in response to lackluster market results.[52]

Here we will summarize four aspects of state-level generation restructuring that we will draw on for our analysis: (1) divestiture of generation facilities by IOUs[53]; (2) requirements for procurement by IOUs of existing or new generation resources; (3) restrictions on siting new generation facilities; and (4) regulatory efforts to facilitate interconnection between new generation resources and utility distribution systems. As noted before, although some of these policies are not typically characterized as within the scope of traditional restructuring, we include them here because of their similar potential to increase competition in the generation sector.

A. *Divestiture*

A key element of state-level restructuring often entailed vertical separation of privately-owned monopoly electric utilities.[54] Some states rejected formal

48. *See generally*, Order No. 888, 75 F.E.R.C. ¶ 61,080 (1996) [hereinafter Order No. 888].

49. *Id.*

50. James Bushnell & Catherine Wolfram, *Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants* (Ctr. for the Study of Energy Markets, Univ. of Cal. Energy Inst., Working Paper No. 140, 2005); Dallas Burtraw, Karen Palmer, & Martin Heintzelman, *Electricity Restructuring: Consequences and Opportunities for the Environment* (Resources for the Future, Discussion Paper No. 00-39 2000).

51. Bushnell and Wolfram, *supra* note 50; Severin Borenstein, Michael Jaske, & Arthur Rosenfeld, *Dynamic Pricing, Advanced Metering and Demand Response in Electricity Markets* (Ctr. for the Study of Energy Markets, Univ. of Cal. Energy Inst., Working Paper No. 105, 2002).

52. *Id*. The "most publicized disappointment" was likely the California electricity crisis of 2000-2001, which followed the California legislature's move to require utility divestiture in 1996. *See* A.B. 1890 (Cal. 1996). In 2001, the California legislature halted divestiture in response to the electricity crisis. *See* A.B. 6 (Cal. 2001).

53. When we use the term "IOU" we use it as a shorthand to refer to the phenomenon of privately owned public utilities, which have been granted a monopoly franchise by the state subject to its regulation, and whose monopoly has been broken up by generation restructuring.

54. Thomas Tribes & Michael Pollitt, *The Direct Costs and Benefits of US Electric Utility Divestitures*, (Energy Pol'y and Rsch. Group, Cambridge Judge Bus. Sch., Univ. of Cambridge, Working Paper No. 1525 2015). Note that electric utility restructuring and divestiture policies specifically targeted generating facilities, and that distribution and transmission networks generally remained structured as franchise monopolies. *Id.*

restructuring inquiries, but instead strengthened regulatory oversight by requiring IOUs to obtain regulatory authorization to construct new generation facilities.[55] On the other end of the spectrum, a few states went so far as to order total divestiture of all generation assets, and to prohibit IOUs from owning or constructing new generation.[56]

Many states implemented competitive policies that fell somewhere in between these two approaches, landing short of requiring full divestiture of generation assets.[57] Such policies included using market power thresholds to trigger state-level generation divestiture or sales requirements.[58] A limited number of states, including California, retained opposing policies to prohibit IOUs from divesting generation assets or, at the very least, require IOUs to obtain permission from regulatory authorities to pursue divestiture.[59]

B. Procurement

Another component of state efforts to introduce competition into the generation aspects of the traditional utility monopoly are state-level regulations that govern how incumbent utilities procure new generation resources or manage existing generation resources. Many states have implemented regulations encouraging or requiring varying levels of competitive procurement of generation by IOUs.[60]

Absent state-level regulations, an IOU in a traditional regulatory setting effectively created its own rules for procuring and managing new electricity generation resources through control and ownership of transmission and distribution lines and monopoly control over the retail market in its service area.[61] Traditional IOUs might build and own generation facilities and pass through costs

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55. *See infra* for discussion of state-level siting requirements.

56. Maine Revised Statutes 35-A § 3204(1) (1996) (ordering full divestment in Maine). In such cases, plant ownership necessarily changed, though sometimes this merely involved the transfer of a generating facility from an IOU to one of its unregulated affiliate companies. *See* Bushnell & Wolfram, *supra* note 50, at 2-3.

57. *See, e.g.*, Del. Electric Utility Restructuring Act of 1999 § 1005.

58. *See, e.g.*, Mich. Public Acts 141, 142 (2000).

59. *See, e.g.*, Az. Corp. Comm'n Final Order, Track A, Sept. 10, 2002 (rolling back previous Arizona regulations requiring divestiture and forbidding divestiture absent permission). For a more rigorous comparison of ownership change versus incentive strengthening in U.S. electricity restructuring, *see generally* Bushnell & Wolfram, *supra* note 50.

60. Paul L. Joskow, Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector, 11 J. ECON. PERSPECTIVES 119, 120 (1997).

61. *Id.* Service area refers to the geographical region that the utility is required to provide service to customers. JOEL B. EISEN, ET AL., ENERGY, ECONOMICS AND THE ENVIRONMENT: CASES AND MATERIALS 84 (4th ed. 2015). For instance, an IOU might decide whether and how to allow independent entities to construct and operate new generation facilities from which it purchases electricity. Joskow, *supra* note 60, at 120. However, even with current FERC rules advancing competitive wholesale markets, the opportunity of IPPs to sell on a wholesale market may be more theoretical than real in areas not within an ISO/RTO – IOUs that control the transmission network may make it practically difficult or impossible for the IPP to actually reach a wholesale market purchaser other than the IOU, giving the IOU monopoly purchasing power and effective control over entry by the IPP. As discussed in Appendix A, to the extent that an IPP is a QF under PURPA, it can use PURPA to force the utility to purchase its power at avoided cost rates.

to their ratepayers, subject to regulatory approval.[62] Other than the (unlikely) possibility of state regulatory disapproval of procurement costs, an IOU may have little incentive to make efficient investments in generation capacity, and may have an incentive to overinvest in order to earn a regulated rate of return on capital projects.[63]

In response to concerns about overinvestment, some states implemented integrated resource planning ("IRP") requirements, pursuant to which utilities must file and publish detailed proposals for a least-cost resource mix that will meet forecasted energy demand.[64] A utility's IRP considers supply-side resources and, in some cases, demand-side resources, and may include policies to promote energy efficiency, new construction, reduced line loss, and customer-owned generation.[65] Done properly, the IRP process is designed to help utilities deliver reliable energy services to customers at the lowest practical costs.[66] As of 2015, thirty-three states have promulgated state-level IRP regulations that require utilities to develop and file IRPs with the state public utilities commission or another regulatory authority, with a range of scope and forecast period requirements.[67]

In practice, fostering efficient generation procurement may require more active state-level intervention than an IRP requirement. Policymakers seeking to more aggressively promote least-cost generation generally favor competitive procurement mechanisms, such as requests for proposals ("RFPs") and auctions.[68]

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62. Joskow, *supra* note 50, at 120. In what is known as a rate case, the state public utilities commission generally determines what capital investment costs an IOU may reasonably pass through to its customers as part of its rate base. Coley Girouard, *How Do Electric Utilities Make Money?* ADVANCE ENERGY PERSPECTIVES (April 23, 2015), https://blog.aee.net/how-do-electric-utilities-make-money. For additional information regarding utility ratemaking, see generally JAMES BONBRIGHT, ALBERT DANIELSEN, & DAVID KAMERSCHEN, PRINCIPLES OF PUBLIC UTILITY RATES (2nd ed. 1988).

63. *See* Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052 (1962). IOUs might find competition from municipal utilities if they raise their costs too much. *See* Harvey L. Reiter, *Competition Between Public and Private Distributors in a Restructured Power Industry*, 19 ENERGY L.J. 333 (1998).

64. *See* REG. ASSISTANCE PROJECT, ELECTRICITY REGULATION IN THE US: A GUIDE 73 (2011), https://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-electricityregulationintheus-guide-2011-03.pdf.

65. *Id.*; Rachel Wilson & Bruce Biewald, Best Practices in Electric Utility Integrated Resource Planning: Examples of State Regulations and Recent Utility Plans 2 (2013), https://www.raponline.org/wp-content/uploads/2016/05/rapsynapse-wilsonbiewald-bestpracticesinirp-2013-jun-21.pdf.

66. Clinton Vince et al., *Integrated Resource Planning: The Case for Exporting Comprehensive Energy Planning to the Developing World*, 25 CASE W. RES. J. INT'L L. 371, 373 (1993); Wilson & Biewald, *supra* note 65, at 2. Ideally, a utility's IRP process will force the utility through a rigorous cost-benefit analysis that can improve economic performance, energy diversification, and customer satisfaction without sacrificing environmental protection. Vince et al., *supra* at 374.

67. Coley Girouard. *Understanding IRPs: How Utilities Plan for the Future*, ADVANCE ENERGY PERSPECTIVES (August 11, 2015) https://blog.aee.net/understanding-irps-how-utilities-plan-for-the-future. A common time horizon for IRPs is twenty years, with a more detailed plan required for the first few years of the IRP. Vince et al., *supra* note 67. Integrated planning has become more complex over time, and must take into account a variety of uncertainties such as fuel costs, electricity market conditions, climate change, and renewable energy and energy efficiency portfolio standards. *See* Girouard, *supra*; Wilson & Biewald, *supra* note 65, at 2.

68. Claire Kreycik et al., *Procurement Options for New Renewable Electricity Supply*, NAT'L RENEWABLE ENERGY LABORATORY v (Dec. 2011), https://www.nrel.gov/docs/fy12osti/52983.pdf; *see generally* John Moorhouse, *Competitive Markets for Electricity Generation*, 14 CATO J. 421 (1995).

Competitive solicitations, which usually take the form of an RFP issued by a utility, are a process by which utilities evaluate and select qualifying bids based on both price and non-price criteria.[69] Auctions can assume a variety of structures, but are generally defined as formal processes in which pre-qualified bidders can win a contract based on price and sometimes volume.[70]

These competitive procurement processes may be limited to select circumstances or apply to procurement of full requirement services.[71] In some states, an IOU may meet the bulk of energy demand from its own generation resources, but must use competitive procurement mechanisms for any incremental "unmet needs" in excess of IOU-generated resources.[72] Other states require IOUs to use competitive procurement mechanisms only in specific instances, such as construction of new generation facilities or executing of long-term contracts.[73]

Another option includes states implementing a hybrid or "tiered" framework for competitive energy procurement, whereby IOUs satisfy their procurement requirements through a combination of competitive procurements and special procurements. In such states, IOUs competitively procure utility-owned generation and long-term contracts but may engage in limited non-competitive procurement activities to promote certain resource types, such as renewable resources, which are not least-cost resources and would not otherwise be selected through a price auction-based competitive procurement process.[74]

C. *Siting New Generation Facilities*

In order to construct new generation facilities, public utilities and other power producers must comply with state regulations, such as environmental laws.[75] In many states, regulations prohibit the construction or operation of a generation facility within a designated area without first obtaining a certificate (often referred to as a "Certificate of Public Convenience and Necessity"), which is granted only if the applicant can show that the new generation is in the public interest, and that the generation project is capable of fulfilling that public interest.[76] State regulatory

69. *See* Kreycik et al., *supra* note 68, at 8.

70. *Id.* at 4. In many markets, generators "bid" into the marketplace to sell power at a price approximating their marginal cost of production. *Id.* at 23. Competitive procurement via auctions poses certain challenges: functionally competitive marketplaces must be sufficiently large so as to be liquid; policymakers can influence market size by dictating auction frequency and quantity of procurement; and technology-neutral auctions can produce imbalanced outcomes where only one technology is liquid and price competitive. *Id.* at 24.

71. *Id.* at 8-27.

72. *See, e.g.*, ARIZ. ADMIN. CODE § 14-2-702 (2020) (requiring Arizona utilities to employ competitive procurement to serve incremental unmet needs).

73. *See, e.g.*, Okla. Admin. Code §165:35-37-1 (2021) (requiring Oklahoma utilities to employ competitive procurement in instances of new generation construction or long-term contract execution).

74. Kreycik et al., *supra* note 68, at 2, 8.

75. John Poakeart, Watt's Going On: Illuminating New York's Electric Generation Siting Process, 19 PACE ENV'T L. REV. 135, 136 (2001).

76. REGULATORY AND PERMITTING INFORMATION DESKTOP TOOLKIT, SOLAR POWER PLANT SITING, CONSTRUCTION AND REGULATION OVERVIEW 1, https://openei.org/wiki/RAPID/Roadmap/7. The doctrine of public convenience and necessity has evolved in response to a variety of judicial and administrative rationales,

authorities generally award CPCNs through an application process in which the applicant provides notice of construction and undergoes an administrative hearing to evaluate public convenience and necessity.[77]

State CPCN requirements impose greater regulatory constraints on public utilities than basic environmental or siting requirements.[78] Under environmental and siting regimes, any number of applicants may ultimately obtain certificates of compliance if they satisfy the qualitative conditions for legal compliance. However, where a state requires a CPCN, the relevant regulatory agency may deny a public utility's application for a generation facility if that agency concludes the associated services would not be in the public interest when considered in conjunction with the availability of similar services in the market.[79] Thus, the CPCN process serves as an explicit barrier to entry and competition.[80] CPCN requirements are generally imposed on all proposed generating facilities, whether being developed by an incumbent IOU or some other entity.[81]

By contrast, in more competitive markets project developers may face a lower bar to demonstrate public need than in traditionally structured markets, potentially demonstrating such public need simply by showing that a new generation plant will contribute to a state's competitive generation objectives.[82] State deregulation policies and siting approval processes therefore interact in important ways.[83]

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including: avoiding "wasteful duplication" of physical facilities; preventing "ruinous competition" among public service companies; preservice services to marginal customers; protecting the existing investments of public service companies; and protecting communities from externalities. William K. Jones, *Origins of Public Convenience and Necessity: Developments in the States, 1870-1920*, 79 COLUM. L. REV. 426, 427-28 (1979). Some RTO/ISOs also require a demonstration of system need before allowing interconnection into the regional grid (e.g., a system impact study). We do not include these requirements separately, unless we find that a state has incorporated those requirements as part of its own regulatory system. In lieu of a CPCN, some states simply require a judicial determination of public need. *See, e.g.*, FLA. STAT. § 403.519 (2021) (requiring judicial finding of public need for new electricity generation). Both systems have the practical effect of requiring a project developer to demonstrate that a new generation facility is consistent with public convenience and necessity.

77. OHIO LEGISLATIVE SERVICE COMMISSION, BILL ANALYSIS, Am. Sub. H.B. 487, 129 Gen. Assembly, at 328, 329 (2012).

78. Avi Zevin et al., COLUM. CTR. GLOB. ENERGY POL'Y, *Building a New Grid without New Legislation: A Path to Revitalizing Federal Transmission Authorities* 1, 20, 22 (Dec. 14, 2020), https://www.energypolicy.columbia.edu/research/report/building-new-grid-without-new-legislation-path-revitalizing-federal-transmission-authorities.

79. Leonard Van Ryn, *Requirements for Offering Electric, Gas and Steam Regulated Utility Services*, NAT'L ASS'N OF REG. UTIL. COMMISSIONERS 6 (Oct. 23, 2017), https://pubs.naruc.org/pub.cfm?id=53908640-2354-D714-5101E7707E6643B5#:~:text=Another%20reason%20to%20deny%20issuance,a%20CPCN%20can%20be%20denied.

80. For instance, state regulatory agencies may deny applications for new facilities where the addition of these new facilities to the available offerings would have no beneficial consequences to local communities. A CPCN regime may explicitly prioritize facilities intended to support in-state load over those intended to provide electricity for export to other states or regions. Jones, *supra* note 76, at 427.

81. MARYLAND PUB. SERV. COMM'N, CPCN PROCESS (Sept. 12, 2019), https://www.psc.state.md.us/wp-content/uploads/sites/2/CPCN-Process-revised-9-12-19.pdf.

82. Kathyrne Cleary & Karen Palmer, *US Electricity Markets 101*, RES. FOR THE FUTURE 4-5 (March 3, 2020), https://www.rff.org/publications/explainers/us-electricity-markets-101/.

83. *See* Pokeart, *supra* note 75, at 142-43.

D. Interconnection Requirements

Well-defined interconnection procedures to utility-operated grid networks are critical to the deployment of non-utility-owned electricity generation. A new generation facility cannot serve demand unless it is connected to existing grid networks, so project developers seeking to develop such facilities must necessarily consider how to efficiently and cost-effectively achieve such connections.[84]

The federal government and state regulatory agencies have promulgated interconnection standards to serve as the "legal rules and procedures" governing the extent to which prospective developers may "plug" new generation facilities into existing distribution facilities.[85] These standards serve both to preserve the safety and reliability of the existing grid infrastructure and associated systems, and to improve the predictability and affordability of interconnection activities.[86]

Federal interconnection standards facilitate the interconnection of large utility-scale generation facilities into the grid through transmission-level interconnection standards.[87] Distribution-level interconnection standards – which are important for small facilities and self-generation by utility customers – remain largely within the domain of state regulation, and therefore vary widely across territories and regions.[88] States have primarily relied on a 2003 Institute of

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84. Paul Sheaffer, *Interconnection of Distributed Generation to Utility Systems: Recommendations for Technical Requirements, Procedures and Agreements, and Emerging Issues*, REG. ASSISTANCE PROJECT 1 (Sept. 2011),http://solarmarketpathways.org/wp-content/uploads/2017/07/rap-sheaffer-interconnectionofdistributedgeneration-2011-09.pdf. A lack of standard interconnection requirements across utility service territories increases the burden of coordination on electricity generators. Lori Bird et al., *Review of Interconnection Practices and Costs in Western States*, NAT'L RENEWABLE ENERGY LABORATORY 6 (Apr. 2011), https://www.nrel.gov/docs/fy18osti/71232.pdf.

85. Ju-Yin Chen, *A Legal Perspective on Grid Interconnection of Renewable Energy and the Role of Electric Utilities*, 4 INT'L J. SMART GRID & CLEAN ENERGY 146, 148 (2015). Interconnection rules generally consist of two components: (1) administrative procedures and technical standards pertaining to the physical interconnection process; and (2) model contractual agreements denoting the associated operational and cost obligations for which the resource owner is responsible. UNITED STATES AGENCY INT'L DEV., NAT'L ASS'N OF REG. UTILITY COMM'RS, AN INTRODUCTION TO INTERCONNECTION POLICY IN THE UNITED STATES 3, https://pubs.naruc.org/pub.cfm?id=5375FAA8-2354-D714-51DB-01C5769A4007.

86. Sheaffer, *supra* note 84, at 2.

87. Laurel Varnado & Michael Sheehan, *Connecting to the Grid: A Guide to Distributed Generation Interconnection Issues*, U.S. DEP'T OF ENERGY, INTERSTATE RENEWABLE ENERGY COUNS.18, 35 (2009), https://www.energy.gov/sites/prod/files/2013/11/f4/connecting_to_the_grid_2009.pdf. As noted *supra*, RSO/IT-Os sometimes have interconnection standards they apply as well. FERC publishes model interconnection procedures and agreements which distinguish between larger generation facilities and smaller ones, presumably because larger systems generally require lengthier connection time and more comprehensive impact studies than do smaller systems. *See* Chen, *supra* note 85, at 148. Order No. 2003 establishes standard generator interconnection procedures and standard agreements that interstate transmission owners and operators (which includes ISO/RTOs as well as IOUs) must incorporate into their open access transmission tariffs for generators having a capacity of more than 20 megawatts. *See generally* Order No. 2003, *Standardization of Generator Interconnection Agreements and Procedure*, 68 Fed. Reg. 49,846 (2003) (to be codified at C.F.R. pt. 35). Order No. 2006 establishes the same for interstate transmission system tariffs on generators having a capacity of 20 megawatts or less. Order No. 2006, 18 C.F.R. § 35 (2005).

88. *See* Order No. 2006, *supra* note 87, at 34,190. (Adding even more control variables leads to only moderate changes in point estimates and small reduction in standard errors, suggesting the current specification is robust to concerns about additional omitted variables.

Electrical and Electronics Engineers ("IEEE") publication, the "IEEE 1547 Standard," which outlined technical specifications and testing requirements for interconnection systems.[89] To date, approximately three quarters of state regulatory agencies have either adopted or referenced the IEEE 1547 Standard.[90]

Certain states, such as Alabama, do not impose state-specific interconnection procedures or requirements.[91] In such states, the utilities that manage existing distribution grids may set rules for generation developers to connect new facilities to an existing grid.[92]

Many states streamline the burden of interconnection oversight by emulating FERC's distinction between large and small generation facilities.[93] Creating separate interconnection requirements at or above a specific facility size can help states retain more stringent oversight over the most complex and impactful interconnection agreements.[94] The most heavily regulated states set size restrictions at or below one hundred kilowatts.[95] Some states, such as Hawaii, impose no size restrictions on interconnection requirements.[96] States can also use interconnection requirements to streamline the process of negotiating and executing and approving interconnection agreements.[97]

E. *Publicly-Owned Utilities*

We also examine the role of public (versus privately-owned) power in this complicated regulatory landscape. In 2017, there were over 2,000 publicly-owned utilities ("POUs") serving over 49 million customers in the U.S., in addition to rural electricity cooperatives, federal power agencies, and community choice

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89. Thomas Basso, *IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electricity Grid,* NAT'L RENEWABLE ENERGY LABORATORY 2, 4 (2014), https://www.nrel.gov/docs/fy15osti/63157.pdf; For additional information regarding the contents of the IEEE 1547 Standard, *see generally* BASSO, *supra*.

90. Basso, *supra* note 89, at 2. In the Energy Policy Act of 2005 ("EPAct 2005"), Congress urged all states and non-state-regulated utilities to consider adopting interconnection standards based on the IEEE 1547 Standard and "current best practices." *Id.*

91. Weston Berg et al., *The 2019 State Energy Efficiency Scorecard,* AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON. 66, 75-76 (October 2019), https://www.aceee.org/sites/default/files/publications/researchreports/u1908.pdf.

92. Some states apply statewide interconnection standards, but only to customer-owned, net-metered systems. *See id*. at 104. Net metering policies allow consumers to self-generate electricity and to receive credits for their unused generation that they can later apply toward electricity used from the grid. Mark James et al., *Planning for the Sun to Come Up: How Nevada and California Explain the Future of Net Metering*, 8 SAN DIEGO J. CLIMATE & ENERGY L. 1, 2-3 (2017). In such cases, the practical impact with respect to utilities' ability to set the terms for generator interconnection is similar to that of having no statewide interconnection standards. *See* Weston Berg et al., *supra* note 91, at 75-76. Because our renewable energy data excludes customer-owned, net-metering systems, we do not include in our study interconnection standards that only apply to those systems.

93. Weston Berg et al., *supra* note 91, at 75-76.

94. Chen, *supra* note 85, at 149.

95. *See, e.g.*, La. R.S. 51:3061 (2005) (specifying a 25-kilowatt size restriction for residential interconnection and a 100-kilowatt size restriction for non-residential interconnection in Louisiana).

96. HAW. REV. STAT. § 269-101 (2012).

97. *See, e.g.*, Order No. 02-046-R (Ark. 2002) (requiring Arkansas utilities to use a Public Services Commission standard interconnection agreement for interconnected facilities). States can achieve this by requiring that generators use standard agreements to interconnect facilities to the grid. *Id.*

aggregators.[98] Whereas privately-held IOUs are subject to state regulatory oversight, POUs and cooperatives are generally subject to local or regional regulatory oversight, and are often subject to limited or no regulation by state public utility commissions, in terms of both their construction and ownership of generation assets and the process by which they determine retail rates for local customers.[99] Rural electricity cooperatives are customer-owned, tax-exempt, nonprofit entities originally established to serve communities where there was not sufficient return on investment in electricity infrastructure to attract IOUs.[100]

Rural cooperatives and municipal utilities are not generally subject to federal restructuring to the same extent as their privately-owned counterparts.[101] Nor do

98. Am. Pub. Power Ass'n, 2019 Statistical Report: A supplement of public power magazine 2, 17, 23 (2019), https://www.publicpower.org/system/files/documents/2019-Public-Power-Statistical-Report.pdf.

99. CAL. ENERGY COMM'N, DIFFERENCES BETWEEN PUBLICLY AND INVESTOR-OWNED UTILITIES https://ww2.energy.ca.gov/pou_reporting/background/difference_pou_iou.html (June 23, 2019); AM. PUB. POWER ASS'N, PUBLIC POWER FOR YOUR COMMUNITY: LOCAL CONTROL. LOCAL PRIORITIES. A STRONGER LOCAL ECONOMY 8, 14, 21, 36 (2016), https://www.publicpower.org/system/files/documents/municipalization-public_power_for_your_community.pdf. Most POUs are divisions of municipalities, but others may be owned by counties, special districts, or even states. POUs may be organized in a variety of ways, including as a municipal department, local or regional district or non-profit entity, and may be managed by a local city council, an elected or appointed board, or other public employees or citizen members. *Id*. at 7, 10, 12, 14, 34. Most municipal utilities were created in the first half of the twentieth century, Shelley Welton, *Public Energy*, 92 N.Y.U. L. Rev. 267, 290 (2017) [hereinafter *Public Energy*], although most states allow citizens to create locally-owned power utilities through a process called municipalization. AM. PUB. POWER ASS'N, PUBLIC POWER FOR YOUR COMMUNITY: LOCAL CONTROL. LOCAL PRIORITIES. A STRONGER LOCAL ECONOMY 28-29, 37 (2016), https://www.publicpower.org/system/files/documents/municipalization-public_power_for_your_community.pdf.

100. *Id.* at 8; Wendy Lyons Sunshine, *How Electric Cooperatives and Commercial Utilities Differ*, THE BALANCE (November 21, 2018), https://www.thebalance.com/electric-cooperatives-vs-utilities-1182700. Most rural cooperatives were formed between the 1930s and the 1960s, driven by federal legislation that provided financial and organizational support for their development. NAT'L RURAL ELEC. COOP. ASS'N, HISTORY: THE STORY BEHIND AMERICA'S ELECTRIC COOPERATIVES AND NRECA (2022), https://www.electric.coop/our-organization/history/. In urban locations with dense populations, IOUs stand to generate more profit per transmission line mile. *Id.* In rural areas where customers are located miles apart, these same IOUs may not realize sufficient profits from servicing these customers to make rural activities economically worthwhile (Sunshine 2018). While initially formed as distribution cooperatives, many rural cooperatives ultimately formed generation and transmission cooperatives that source power by purchasing wholesale generation or by owning their own generation facilities. UNIV. OF WIS. CTR. FOR COOPS., RESEARCH ON THE ECONOMIC IMPACT OF COOPERATIVES: RURAL ELECTRIC, http://reic.uwcc.wisc.edu/electric/. Rural cooperatives may participate in wholesale electricity markets by purchasing electricity from IOUs or rural generation and transmission cooperatives. Wilbur Earley, *In Competition in the Electric Industry: Emerging Issues, Opportunities, and Risks for Facility Operators*, THE NATIONAL ACADEMIES PRESS, 6 (Fed. Facilities Council ed. 1996). In addition, to generation, transmission, and distribution activities, rural cooperatives often participate in community development activities. UNIV. OF WIS. CTR. FOR COOPS., RESEARCH ON THE ECONOMIC IMPACT OF COOPERATIVES: RURAL ELECTRIC, http://reic.uwcc.wisc.edu/electric/.

101. Order 888 requires "public utilities," defined as those utilities that FERC regulates under Sections 205 and 206 of the Federal Power Act, to file wholesale open access transmission tariffs and rates with FERC. Wallace Tillman & Susan Kelly, *Orders 888 and 889, and Wholesale Open Access Transmission: Lots of Questions (and Some Answers) for Cooperatives*, 37 Mgmt. Q. 10 (1996). Neither rural cooperatives nor municipal utilities qualify as public utilities for the purpose of FERC regulation. 16 U.S.C. § 824(e)-(f). When rural cooperatives participate in ISOs and RTOs, they cannot be required to participate in the competitive electricity markets. Tillman & Kelly, *supra*.

states generally impose significant generation restructuring on rural cooperatives or municipal utilities.[102] By default, state-level restructuring legislation applies to regulated utilities but not to rural cooperatives.[103] Therefore, unless the state promulgates regulations that explicitly refer to cooperative utilities, rural cooperatives and other cooperative entities are exempt from restructuring legislation. While some states have chosen to regulate interconnection with respect to rural cooperatives, very few states have chosen to regulate municipal utilities or rural cooperatives with respect to other restructuring factors.[104]

In addition to generally being exempt from direct state or federal mandates for generation restructuring, POUs are public entities that are responsive to local voters or customers, as opposed to shareholders, and therefore may have very different decision-making processes and goals than IOUs. Accordingly, we treat POUs as an important independent factor for how restructuring efforts have shaped renewable energy outcomes.

III. EMPIRICAL ANALYSIS

We compiled data on generation restructuring policies on the state level from 1990 to 2018. We also collected data on a range of other factors that are important for determining whether a state might invest in renewable energy, including the potential for solar or wind production, local political support for environmental action, and income. We also include state and year fixed-effects to take into account other time- and location-specific factors that might shape whether a state would produce more renewable energy. We then analyzed, using regression analysis, whether these various factors had a statistically meaningful relationship with the proportion of a state's overall electricity capacity that is provided by renewable energy. This analysis allows us to quantitatively assess the extent to which there is a relationship between generation restructuring policies and greater investment in renewable energy.

We also conducted additional analyses to examine whether state-level generation restructuring policies might have a larger or smaller impact on renewable energy investment when those policies are combined with other important energy policies, specifically renewable portfolio standards, the overall number of renewable policies in a state, and retail restructuring.

Finally, we assess the extent to which the relationship between restructuring policies and renewable energy capacity differs between states with larger and

102. At least eight states, including Louisiana and Montana, have promulgated interconnection requirements that explicitly apply to cooperative utilities as well as regulated utilities. AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON., INTERCONNECTION STANDARDS (2018), https://database.aceee.org/state/interconnection-standards; *See* La. R.S. 51:3061 (2005) (requiring cooperative utilities in Louisiana to provide net metering and interconnection to distributed generation systems powered by renewable fuels).

103. Sam J. Ervin, IV, *The state of Energy Regulation in the United States*, NAT'L ASS'N OF REG. UTIL. COMMISSIONERS 9, 12, https://pubs.naruc.org/pub.cfm?id=538F9979-2354-D714-51EE-34D36131BC2C.

104. IND. CODE ANN. § 8-1-8.5-1 (a)(1), (b) (LexisNexis 2021) (requiring municipal and cooperative utilities to obtain a certificate of public need and necessity in order to construct new generation). Indiana appears to be the only state that explicitly requires cooperative utilities to comply with siting requirements that normally apply to regulated utilities.

smaller components of their electricity system in municipal or cooperative ownership. For this analysis, we split the states into two groups – those with higher public ownership of electricity capacity than the median state, and those with lower public ownership than the median state. We then repeat our first regression analysis (examining relationships between state-level restructuring policies and renewable capacity) for each of these two groups.

We provide full details on our methodology and data coding in Appendix B. We present the results of our analyses in the rest of this Part III.

A. Generation Restructuring and Renewable Capacity

Table 1 reports the results on the relationship between generation restructuring and the share of renewable capacity in a state's generation portfolio. The estimates are from an essential Difference-In-Differences (DD) research design, based on the identifying assumption that the exact timing of these restructuring policies are quasi-random. In both columns (1) and (2), proportion of renewable capacity is the dependent variable and different types of generation restructuring policies are the independent variables. Column (1) provides the estimate of the relationship between generation restructuring and renewable capacity share with a full range of control variables; Column (2) excludes those controls, and only includes state fixed effects, year fixed effects, and state-specific trends.[105]

	Proportion of Renewable Capacity	
	(1)	(2)
Divestiture prohibited	0.007	0.014
	(0.019)	(0.011)
Divestiture optional	0.013**	0.009
	(0.006)	(0.005)
Divestiture required	0.017**	0.017**
	(0.008)	(0.008)
Some procurement requireme-nts	0.005	-0.003
	(0.006)	(0.005)
CPCN required only	0.011	0.025*

105. Providing the comparison between the analysis in Column (1) and Column (2) makes clear how robust our results are to the consideration of a wide range of additional factors that might affect investment in renewable energy in a state. Adding even more control variables leads to only moderate changes in point estimates and small reduction in standard errors, suggesting the current specification is robust to concerns about additional omitted variables.

	(0.014)	(0.013)
Environmental or site approvals only	-0.001	0.003
	(0.009)	(0.009)
No siting requirement	-0.008	0.010
	(0.010)	(0.008)
Some interconnection requirements	0.005	-0.002
	(0.006)	(0.006)
Private capacity in ISO/RTO	0.011**	0.008*
	(0.005)	(0.004)
State-year control set	No	Yes
State-specific trend	Yes	Yes
State FE	Yes	Yes
Year FE	Yes	Yes
Observations	1,450	1,450

Table 1: Effects of Generation Restructuring on Renewable Capacity[106]

There is a wide variation in the impacts of different state-level generation restructuring policies on renewable energy investment. Divestment has a large impact – a state that mandates divestiture raises the proportion of renewable capacity by 0.017, a 34% increase from the mean level of renewable energy capacity of 0.05.[107] A policy that makes divestiture optional also tends to increase proportion of renewable capacity, although the estimate is much smaller and imprecise.[108] On the other hand, prohibitions on divestiture, which are generally understood as rolling-back or opposing generation restructuring, do not have negative effects on renewable technology investment.[109]

From Column (2), we can see that compared to the most stringent siting requirements, making either environmental approval or a CPCN or both optional generally increases the proportion of renewable capacity. For instance, a state that requires only a CPCN has an increase in renewable energy capacity of 0.025, or 50% from the mean.[110] There are smaller and insignificant effects from further relaxation of siting requirements.

106. Notes: standard errors clustered by states are in parentheses. $^{*}p<0.1$; $^{**}p<0.05$; $^{***}p<0.01$.

107. *See* Table 1.

108. *Id.*

109. *Id.*

110. *Id.*

The estimates of impacts of policies to promote more interconnection and open procurement are close to zero in the sample, even though they are generally understood as advancing generation restructuring.

Finally, as shown in Column (2), the development of ISOs and RTOs increases proportion of renewable capacity by 0.008, a 16% of increase from the mean.[111]

B. *Interaction effects with other policies of interest*

We next examine how the impacts of state-level generation restructuring might modify the effects of three other major state-level electricity policies: RPS, overall renewable energy programs,[112] and retail restructuring. We undertake this by analyzing the interaction of these policies in a regression model. As in Part III.A, the dependent variable for all of these analyses is the proportion of a state's electricity capacity that is renewable. Control variables, state and year fixed effects, and state-specific trends are included in all specifications (similar to Column (2) in Table 1). The independent variables are measures of different types of state-level generation restructuring policies, the three non-restructuring state-level electricity policies, and their interaction. For simplicity, Table 2 only reports the coefficients for the interaction terms. Results for RPS are in Column (1). Results for overall renewable energy programs are in Column (2). Results for retail restructuring are in Column (3).

	Proportion of Renewable Capacity		
Non-restructuring state-level electricity policy:	RPS	Cumulative number of renewable energy programs	Retail restructuring
	(1)	(2)	(3)
Divestiture prohibitedXPolicy	-0.004	0.004	-0.003
	(0.012)	(0.004)	(0.014)
Divestiture optionalXPolicy	-0.007	-0.001	-0.010
	(0.010)	(0.002)	(0.014)

111. *See* Table 1.

112. Specifically, we use the reports from the DSIRE database that cover the full range of state renewable energy policies, including subsidies. See Appendix B for more details.

Divestiture requiredXPolicy	-0.025	-0.002	-0.011
	(0.019)	(0.002)	(0.015)
Some procurement requirementsXPolicy	-0.006	0.00005	-0.016*
	(0.008)	(0.002)	(0.009)
CPCN required onlyXPolicy	-0.011	-0.001	-0.031***
	(0.015)	(0.003)	(0.009)
Environmental or site approvals onlyXPolicy	0.013	0.008***	0.007
	(0.016)	(0.003)	(0.012)
No siting requirementXPolicy	-0.001	0.007*	0.011
	(0.019)	(0.003)	(0.013)
Some interconnection requirementsXPolicy	0.009	-0.00003	0.014
	(0.009)	(0.004)	(0.012)
Private capacity in ISO/RTOXPolicy	0.017*	0.003	-0.003
	(0.009)	(0.002)	(0.008)
Control set	Yes	Yes	Yes
State-specific trend	Yes	Yes	Yes
State FE	Yes	Yes	Yes
Year FE	Yes	Yes	Yes
Observations	1,450	1,450	1,450

Table 2: Interaction Effects of Generation Restructuring and Other State-Level Electricity Policies[113]

113. Notes: standard errors clustered by states are in parentheses. *p<0.1; **p<0.05; ***p<0.01.

In general, states that simultaneously implement generation restructuring along with one of these other electricity policies do not appear to see larger increases in renewable capacity, compared to the impacts of these policies individually. There are a few exceptions. It appears that when a state both enacts an RPS and is included in an ISO/RTO, the positive effects of a RPS are higher than in states that simply enact an RPS but are not in an ISO/RTO.[114] It also appears that state changes to generation siting policies do appear to enhance the impacts of overall renewable energy programs.[115] Finally, states that simultaneously enact retail restructuring and policies that either promote open procurement or less stringent siting requirements appear to have lower levels of renewable capacity compared to states that enact those policies without retail restructuring.[116] This last outcome may be the result of consumer preferences. If consumers prefer non-renewable generation technology and select it through retail restructuring programs that enhance consumer choice, generation restructuring can further facilitate meeting consumer demand for non-renewable electricity by reducing barriers to entry.

C. *Public Ownership*

Finally, we examine whether the exemption of public entities from generation restructuring means that in states with higher levels of municipal or cooperative ownership of electricity capacity, the impacts of state-level generation restructuring on renewable energy investment are reduced. We test this by estimating the model for two different subsamples: states with below-median and above-median public ownership in 1990.

	Proportion of Renewable Capacity	
	States with below-median public ownership in 1990	States with above-median public ownership in 1990
	(1)	(2)
Divestiture prohibited	0.040***	-0.030
	(0.010)	(0.031)
Divestiture required	0.029***	0.002
	(0.008)	(0.005)
Divestiture optional	0.036***	-0.017
	(0.010)	(0.016)
Some procurement requirements	-0.007	-0.005

114. *See* Table 2.

115. *Id.*

116. *Id.*

	(0.005)	(0.007)
CPCN required only	-0.021**	0.041**
	(0.008)	(0.016)
Environmental or site approvals only	0.009	0.006
	(0.012)	(0.012)
No siting requirement	0.007	0.005
	(0.009)	(0.016)
Some interconnection requirements	-0.007	0.001
	(0.007)	(0.009)
Private capacity in ISO/RTO	0.008	0.009
	(0.006)	(0.007)
Control set	Yes	Yes
State-specific trend	Yes	Yes
State FE	Yes	Yes
Year FE	Yes	Yes
Observations	1,450	1,450

Table 3: Differential Effects of Generation Restructuring Under Different Public Ownership[117]

As shown in Table 3, overall, impacts of generation restructuring in states with high public ownership are similar to states with low public ownership, except for impacts of divestiture policies.[118] The positive effects of reforming divestiture policies on renewable energy investment are higher in states with low public ownership.[119]

IV. CONCLUSION AND RECOMMENDATIONS

A key result from our analysis is that at the state level, divestiture and siting restrictions matter. While the absolute magnitude of the changes from these policies appears small, they represent very large increases from the low baseline level of renewable energy capacity in our timeframe. For instance, siting policy restructuring increases renewable energy capacity levels in a state by 50%.[120]

117. Notes: Standard errors clustered by states are in parentheses. *p<0.1; **p<0.05; ***p<0.01.

118. *See* Table 3.

119. *Id.*

120. The other state-level restructuring policy that was likely to result in significant improvements in renewable technology adoption – and that generally consistently did so across our models – is allowing or even requiring divestiture.

Given the importance of state-level siting policy for renewable energy deployment, states may want to consider further reforms to environmental review and permitting requirements for renewable energy projects. Local opposition to renewable energy projects is now often cited as a major obstacle to renewable energy deployment in the United States,[121] and there have been calls that states should preempt local environmental and land-use restrictions on renewable energy projects.[122] For instance, New York has undertaken limited preemption of local regulation.[123] In the other direction, state legislatures hostile to renewable energy have empowered local landowners to prevent the siting of renewable energy projects.[124] Our findings indicate that reducing restrictions on siting renewable energy projects is an important policy lever for states seeking to advance renewable energy investments. However, in deciding whether and how to preempt local control over siting, state governments will have to weigh important considerations of equity and voice for these communities, particularly historically disadvantaged communities that have had a legacy of environmental injustice.

We also found that at the federal level, development of ISOs/RTOs matter: it leads to higher levels of renewable energy investment in the electric power sector.[125] In addition, if a state's utilities are members of an ISO/RTO, that will further amplify the impacts of RPS policies in advancing renewable energy investment. This finding is significant given the current debates in a number of states, including in the southeast and in California, about whether to join an ISO/RTO or geographically expand an existing ISO/RTO.[126] Our analysis

121. Ivan Penn, *Offshore Wind Farms Show What Biden's Climate Plan is Up Against*, N.Y. TIMES (last updated Oct. 13, 2021), https://www.nytimes.com/2021/06/07/business/energy-environment/offshore-wind-biden-climate-change.html; Jim Carlton, *Solar Power's Land Grab Hits a Snag: Environmentalists*, WALL ST. J. (June 4, 2021), https://www.wsj.com/articles/solar-powers-land-grab-hits-a-snag-environmentalists-11622816381; Benjamin Storrow, *A Farmer's Right for Solar Reveals a U.S. Land Problem*, CLIMATEWIRE (Apr. 19, 2021), https://www.eenews.net/articles/a-farmers-fight-for-solar-reveals-a-u-s-land-problem/; Joseph Bernstein, *"Corrosive Communities": How a Facebook Fight Over Wind Power Predicts the Future of Local Politics in America*, BUZZFEEDNEWS (Dec. 17, 2021), https://www.buzzfeednews.com/article/josephbernstein/facebook-groups-wind-turbine-construction.

122. Noah Smith, *The Left's NIMBY War Against Renewable Energy*, BLOOMBERG OPINION (Sept. 12, 2021), https://www.bloomberg.com/opinion/articles/2021-09-12/the-left-s-nimby-war-against-renewable-energy.

123. Emily Pontecorvo, *How New York is Trying to Build Lots of Renewables, Fast*, GRIST (Nov. 30, 2020), https://grist.org/energy/how-new-york-is-trying-to-build-lots-of-renewables-fast/.

124. Jeffrey Tomich, *Strangled Ohio Wind Industry: 'We Don't Want to Give Up*,' ENERGYWIRE (July 12, 2019), https://www.eenews.net/articles/strangled-ohio-wind-industry-we-dont-want-to-give-up/ (describing how Ohio legislation that imposed large setback requirements from property lines unless the neighbor consented to the project reduced wind projects in the state significantly).

125. NAT'L GOVERNORS ASS'N, ELECTRICITY MARKETS 101, https://www.nga.org/electricity-markets/ (last visited Feb. 18, 2022).

126. States in the southeast have been debating whether to form a new RTO or join an existing one. Catherine Morehouse, *Groups Ask Congress for First-of-its-Kind Cost Analysis of RTOs Amid Market Expansion Debate*, UTILITY DIVE (July 8, 2021), https://www.utilitydive.com/news/groups-ask-congress-for-first-of-its-kind-cost-analysis-of-rtos-amid-market/602995/; Catherine Morehouse, *Duke-Supported Group Launches Campaign Against North Carolina Bill to Examine Wholesale Market Reform*, UTILITY DIVE (May 24, 2021), https://www.utilitydive.com/news/duke-supported-group-launches-campaign-against-north-carolina-bill-to-

indicates that, all other things being equal, ISO/RTO membership can help advance renewable electricity investment, both directly and by accelerating the benefits of RPS programs.

For states where both RPS and ISO/RTO membership are not politically feasible policy options, our analysis also indicates that siting-level restructuring at the state level can still have an important impact on renewable energy investment. If siting-level restructuring is more politically feasible than either an RPS or ISO/RTO membership, then it can provide an additional pathway forward for renewables policy.

On the other hand, other restructuring efforts to lower barriers to entry in electricity generation appeared to have no effect on efforts to decarbonize the electric power sector. We did not find strong relationships between renewable capacity and requirements for interconnection and procurement– despite their prominence in debates around restructuring.[127] This lack of any such relationship indicates that these interventions were relatively marginal in terms of changing the competitive landscape for renewable energy in particular, or that perhaps that they were relatively marginal in terms of opening markets in general. For interconnection, the fact that most state policies apply to primarily small generators also support this second possibility.

Our results also indicate that restructuring potentially has benefits for increasing the political support for climate policy over the long run by increasing the entry of renewable energy investments into the electricity sector, and accordingly increasing the entities that have a stake in increasing policy support for renewable energy in the future.

The results showing that high level of public ownership in general does not affect the relationship between renewable power investment and generation restructuring is a cautionary point for advocates who argue, in either direction, that either restructuring or public ownership are important drivers of renewable energy transitions. On the public ownership side, advocates have sought to drive decarbonization through massive public intervention in energy systems – such as proposals for a Green New Deal,[128] and scholars have noted the potential for public energy to drive climate transitions.[129] But public systems are responsive to the political landscape – and to the extent that political landscape is hostile to decarbonization (whether for ideological or interest group reasons), it may be much harder to initiate decarbonization in a public system. Reciprocally, where the political landscape is friendly to decarbonization, a public system may facilitate a rapid transition. In contrast, while a restructured system that is

poten/600636/. California has been debating whether to expand its current ISO, which is limited to California, to a wider range of states in the Western US. For an overview of the debate, *see* NEXT 10, A REGIONAL POWER MARKET FOR THE WEST: RISKS AND BENEFITS, https://www.next10.org/publications/regional-grid (July 17, 2018).

127. See, supra, Table 3.

128. Lisa Friedman, *What is the Green New Deal? A Climate Proposal Explained*, N.Y. TIMES, (February 19, 2019), https://www.nytimes.com/2019/02/21/climate/green-new-deal-questions-answers.html.

129. Public Energy, supra note 99.

relatively insulated to direct political control may allow for more openings for renewable energy and other decarbonization efforts to take off, it is also vulnerable to the whims of pricing for renewable resources relative to other resources and to decisions by individual utilities and IPPs as to investment. In addition, restructured markets require governance rules,[130] governance rules that can be manipulated and coopted by private actors in ways that interfere with renewable energy transitions, particularly when the governance rules are delegated primarily to private actors.[131]

Given these dynamics, advocates for decarbonization in jurisdictions where the politics are favorable to renewable energy right now might want to embrace public intervention. But even here, we note a potential caution. Because public systems are politically responsive, they will also be responsive to shifts in the political landscape more than restructured systems. If the public investments can be powerful enough and long-term enough that they shift the bigger political landscape—for instance by building up powerful pro-decarbonization interest groups—then the risk of political vacillation is less, and public approaches may be an attractive approach, particularly if they can move quickly. Restructured wholesale markets may provide a buffer or resilience against the changes in political winds that could otherwise undermine investments in decarbonization – but they are vulnerable to the whims of the private sector.

APPENDIX A: FEDERAL LAWS AND POLICIES ADVANCING GENERATION RESTRUCTURING

The history of federal efforts to advance restructuring of electricity generation in the United States begins in 1978, when Congress passed the Public Utility Regulatory Policies Act (PURPA).[132] The law was enacted on the heels of the oil embargo of the 1970s and the growing environmental movement, with the intent of increasing efficiency in power markets.[133] However, one short section of the bill, section 210, focused on shifting how power is generated and supplied.[134] This section reflected a broad policy goal to increase the amount of electricity produced from facilities that could use fossil fuels more efficiently and from facilities generating power from renewable resources such as wind, solar, biomass, geothermal, hydro and waste.[135]

130. William Boyd, *Just Price, Public Utility, and the Long History of Economic Regulation in America*, 35 YALE J. REGUL. 721-777 (2018).

131. *See* Shelley Welton, *Rethinking Grid Governance for the Climate Change Era*, 109 CALIF. L. REV. 209 (2021).

132. Public Utility Regulatory Act of 1978, Pub. L. 95-617, 92 Stat. 3117 (1978) (codified as amended at 16 U.S.C. § 2601 note (2011)).

133. RICHARD HIRSH, POWER LOSS 73-74 (1995); Jeffrey Watkiss & Douglas Smith, *The Energy Policy Act of 1992: A Watershed for Competition in the Wholesale Power Market*, 10 YALE J. ON REGUL., 447, 452-54 (1993).

134. P.L. 95-617, 92 Stat. 3117, 3135-36 (codified at 16 U.S. Code § 824a–3) (hereinafter § 210).

135. *See* HIRSH, *supra* note 133, at 81-83.

PURPA section 210 proved to be the most radical and influential part of the law and is often credited with transforming electricity generation-side markets in the United States in the subsequent forty years.[136] It is also generally considered the first of many federal steps toward encouraging competitive electricity generation markets.[137] To summarize a complicated history, PURPA provided guaranteed market access for certain types of independent power producers, prevented utilities from using their transmission and distribution systems to deny market access to new entrants,[138] and exempted independent power producers from traditional utility cost of service and corporate regulation.

Following PURPA's passage, Congress turned toward transmission access. The only way that a generator can reach consumers is via transmission lines, and because of limited transmission infrastructure, whoever controls that infrastructure controls the market. Historically, traditional utilities owned the transmission on which they transported the power they generated and often had little incentive to open those lines to competitors, sometimes denying access outright.[139] Even if a utility opted to open access, it could charge additional costs to stifle competition, or otherwise create obstacles for competitors.[140] To address this, Congress passed the Energy Policy Act of 1992 ("EPAct 1992").[141] Among other things, EPAct 1992 authorized the Federal Energy Regulatory Commission (FERC) to order any transmitting utility to grant access to their transmission infrastructure to transmit power ("wheeling"), so long as doing so was consistent with maintaining reliability and in the public interest.[142] The authority was discretionary—FERC was not *required* to issue these orders, merely *authorized* to do so.[143]

Over the next few years, FERC expanded beyond this model of case-by-case approval of individual applications for wheeling and required all utilities to permit other entities to wheel their power on utility-owned transmission lines.[144] In 1996, FERC issued Orders 888 and 889, mandating that all utilities in control of transmission services offer nondiscriminatory access to that transmission for non-utility generators.[145] This step is often referred to "functional unbundling" as it also officially separated – or unbundled – the sale of electricity from the transmission of electricity, which had previously generally been bundled

136. *Id*. at 73.

137. *Id.*

138. *Id.* at 87.

139. Watkiss & Smith, *supra* note 133, at 455.

140. *Id.* at 455 n.32 (providing multiple examples of denial of access or additional costs).

141. Energy Policy Act of 1992, Pub. L. 102-486, 106 Stat. 2776 (1992) (codified as amended at 42 U.S.C. § 13201 note (1992)).

142. Watkiss & Smith, *supra* note 133, at 461 (citing 16 U.S.C, §§ 824j(a)-(b), 824k(a), (i), (j)).

143. *Id.* at 462.

144. For a discussion of FERC's actions that preceded the issuance of Orders 888 and 889, see e.g., Ari Peskoe, *Is the Utility Syndicate Forever*, 42 ENERGY L.J. 1 (2021); Harvey Reiter, *The Contrasting Policies of the FCC and FERC Regarding the Importance of Open Transmission Networks in Downstream Competitive Markets*, 57 FED. COMM. L.J. 246, 258-59 (2005).

145. Order No. 888, *supra* note 48; Order No. 889, *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, 61 Fed. Reg. 21,737-01 (1996).

together.[146] FERC's actions freed up the infrastructure necessary for entities other than utilities to access electricity markets, increasing competition.[147]

To support this transition, Order 888 also promoted (though did not mandate) the development of independent system operators (ISOs) in an attempt to further facilitate competitive access to transmission infrastructure,[148] and provided detailed guidance on principles for setting up and managing these systems.[149] ISOs are independent of any power generator or utility, and their primary function is to coordinate the operation of transmission system infrastructure and wholesale transactions of electricity across these systems.[150] Although the ISOs do not own transmission, transmission owners grant them complete control over facilitating system use.[151]

In 2000, FERC issued Order 2000[152], which created Regional Transmission Organizations (RTOs). Similar to ISOs, RTOs operate transmission and facilitate competitive electric markets across transmission lines. RTOs have twelve set characteristics laid out by FERC which they must follow, including a requirement for a broader monitoring of bulk power markets operated by such RTO.[153] In Order 2000, the Commission noted its objective for "all transmission-owning entities in the Nation, including nonpublic entities, to place their transmission facilities under the control of appropriate RTOs in a timely manner."[154] Order 2000 set up a voluntary approach by which public and nonpublic utilities that own transmission would consider and develop RTOs.[155]

Today, two-thirds of the country receives electricity from competitive markets managed by an RTO or ISO.[156] Each RTO and ISO—similar to the markets they operate in—is uniquely structured.[157] Areas that fall within the jurisdiction of an RTO or ISO may still contain significant incumbent vertically-

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146. Order No. 888, *supra* note 48, at p. 21,551; *see also* JAMES MCGREW, FERC FEDERAL ENERGY REGULATORY COMMISSION 154 (2d ed. 2009).

147. Order No. 888, *supra* note 48.

148. *Id.* at pp. 21,593-94; *see also Regional Transmission Organizations/Independent System Operators*, FERC https://www.ferc.gov/industries-data/electric/power-sales-and-markets/rtos-and-isos (last updated Feb. 17, 2022).

149. Order No. 888, *supra* note 48.

150. *Id.* at 21,596.

151. *ISO History*, CALIFORNIA INDEPENDENT SYSTEM OPERATOR, http://www.caiso.com/about/Pages/OurBusiness/ISO-history.aspx (last visited Feb. 10, 2022). Transmission owners that participate in ISOs can include including investor-owned utilities, public power entities, Rural Utility Service borrower generation and transmission cooperatives, and independent transmission companies.

152. Order 2000, *Regional Transmission Organizations*, 89 FERC ¶ 61,285 (1999) [hereinafter Order 2000].

153. *Id.* at pp. 5, 463.

154. *Id.* at p. 4.

155. *Id.* at p. 6.

156. MCGREW, *supra* note 146, at 161. Of the RTO/ISOs, Mid-Atlantic ISO, ISO New England, New York ISO, PJM , Southwest Power Pool, and California ISO are within FERC's purview under the Federal Power Act. *Id.* Texas' ERCOT facilitates a competitive market but is not under FERC's jurisdiction.

157. *See* Welton, *supra* note 131, at 227-32.

integrated utility monopolies subject to state regulation, including regulation of retail prices. For instance, in California, most ISO participants are IOUs that hold or have until recently held near monopolies over significant portions of the region, and are subject to state regulatory approval of investments, costs, rates and more.[158] Other RTOs and ISOs include states with much more significant deregulation, such as Pennsylvania. How ISOs and RTOs interact with incumbent regulated utilities, utility regulators and regional planning decisions therefore varies based on regional structures. However, the common feature is they control access to transmission in their region and manage wholesale markets.

Over time, in some areas, these entities and their roles have expanded beyond facilitating the wheeling of electricity over transmission systems and wholesale transactions. Some have assumed responsibly for long-term resource adequacy planning by operating markets to encourage the construction of new generation resources, such as capacity markets.[159]

In the regions overseen by an RTO or ISO, wholesale rates are generally set by a wholesale market running under the rules of the RTO or ISO. Because these rules and rates govern wholesale power transactions, they are therefore still overseen by FERC, who must ensure that they are "just and reasonable" under the Federal Power Act.[160] FERC has generally adopted a flexible approach, allowing these markets to evolve in different ways.[161] FERC and the federal courts have, however, prevented some state government actions in RTO and ISO regions that affect generation as impeding FERC's jurisdictional authority.[162] The Supreme Court has stated, that states are allowed to take regulatory and legal action to encourage new generation, or different types of generation, so long as the related measures are "untethered to wholesale market participation,"[163] and do not "impermissibly intrude[s] upon the wholesale electricity market, a domain

158. "Investor-owned utilities (IOUs) are private electricity and natural gas providers. California Public Utilities Commission (CPUC) oversees IOUs. Pacific Gas and Electric, San Diego Gas and Electric, and Southern California Edison comprise approximately three quarters of electricity supply in California." CAL. ENERGY COMM'N, *Differences Between Publicly and Investor-Owned Utilities*, https://ww2.energy.ca.gov/pou_reporting/background/difference_pou_iou.html. (last visited June 23, 2019).

159. *See* Welton, *supra* note 157, at 232. A capacity market is a market in which a buyer will pay a seller for agreeing to have additional electricity capacity "online and ready to produce" by a certain time in the future. Seth Blumsack, PENN. STATE UNIV., *EME 801 Energy Markets, Policy, and Innovation: Regional Transmission Organizations*, https://www.e-education.psu.edu/eme801/node/535 (last visited Feb. 19, 2022). These markets generally exist to ensure that sufficient future resources will be available to meet future demand. *Id.*

160. *See* MCGREW, *supra* note 146, at 193-94.

161. FERC, CENTRALIZED CAPACITY MARKET DESIGN ELEMENTS 2 (2013) ("The Commission has provided each region with flexibility as to market design and has not required a "one-size fits all" approach. However, the primary goal of each of these markets is the same: ensure resource adequacy at just and reasonable rates through a market-based mechanism that is not unduly discriminatory or preferential as to the procurement of resources."); *see also* McGrew, *supra* note 146, at 204.

162. Hughes v. Talen Energy Mktg., LLC, 136 S. Ct. 1288, 1299 (2016) (holding that a Maryland program guaranteeing certain generators a minimum price if they bid into, and cleared, an RTO capacity market was preempted, because it was too closely tethered to wholesale rates governed exclusive by FERC).

163. *Id.* at 1299 (quoting Brief for Respondent at 40, *Hughes*, 136 S. Ct. 1299 (Nos. 14-614, 14-623).

Congress reserved to FERC alone."[164] This transition to open access, functional unbundling, regional transmission governance and expanded wholesale markets has had the effect of expanding FERC's regulatory power, as more power is produced, sold, and transmitted through federally regulated interstate wholesale markets rather than under the control of state regulated IOUs.[165]

APPENDIX B: METHODOLOGY

A. Empirical Strategy

We estimate the effects of generation restructuring on the adoption of renewable energy in the electric power sector. Because different types of restructuring policies have different details and impacts, we use separate policy measures for each type of policy in our analysis. Therefore, in all models we consider the conditional average effects of different types of state- and federal-level restructuring efforts, including divestiture (DIV), procurement (PROC), siting (SIT), interconnection (INT), and Independent System Operator/Regional Transmission Organization (ISO) status.

In general, investment in renewable generation capacity at the state level is a function of a range of economic, political, geographical and other idiosyncratic factors: user demands, costs of different generation technology, prices of fuels, monetary incentives from renewable energy programs, climate and environmental policies affecting the electricity market (such as cap-and-trade programs), relative strengths of different incumbent interest groups, resource abundance, and so on. Our baseline model assumes that they have the following additive, linear form:

$$\begin{aligned} Model\ A\colon y_{st} = {} & \beta_1^{DIV} DIV + \beta_1^{PROC} PROC + \beta_1^{SIT} SIT + \beta_1^{INT} INT + \beta_1^{ISO} ISO \\ & + X_{st}\Gamma + \eta_s + \eta_t + \alpha^s t + \epsilon_{st} \end{aligned}$$

The dependent variable, y_{st}, denotes the proportion of renewable capacity in the generation portfolio in state s and year t. The explanatory variables of interest, p = DIV, PROC, SIT, INT, are vectors of dummy variables coded as one if a state has the policy p in force in year t.[166] ISO is coded as one if a state has any generation capacity that is privately-owned and in one of the ISO/RTO. Construction of these variables is further discussed below. η_s denotes the vector of state fixed effects, which captures time-invariant, state-specific unobserved factors that affect the outcome variable. One example of these factors is local climate conditions, such as perennial wind speed in Iowa and sunshine duration in California, factors that are associated with renewable resource potential. Year

164. *Id.* at 1292. What remains tethered and untethered is still an active topic for determination. While the Maryland program was held to be too closely related to wholesale markets, for example, the issuance and sale of Zero Emissions Credits alongside electricity sales to further encourage the development of nuclear energy has been held not preempted. *See* Vill. of Old Mill Creek v. Star, Nos. 17 CV 1163, 17 CV 1164, 2017 WL 3008289, at 9*, 10* (N.D. Ill. July 14, 2017); Coal. for Competitive Elec. v. Zibelman, 272 F. Supp. 3d 554, 571 (S.D. NY 2017).

165. FERC, *Electric Power Markets*, https://www.ferc.gov/electric-power-markets# (last updated July 20, 2021).

166. Note that both DIV and SIT have multiple levels. We assign a dummy variable to each level and use the level with least perceived effectiveness in advancing generation restructuring as the reference level.

fixed effects, denoted by η_t, absorb common factors influencing all states alike in a year, and they can control for nationwide shocks like tariffs imposed on imported solar panels. $\alpha^s t$ are a set of state-specific trends that can control for more unobservable heterogeneity. X_{st} denotes the vector of control variables varying at the state-year level used to capture economic, political, geographic determinants of investment and production of renewable electricity, including renewable energy programs, retail restructuring status, population, income, electricity imports and exports, nuclear fuel/coal/natural gas consumption, and so on.[167] ϵ_{st} contains unobserved determinants that are state-specific and time-varying. Throughout the analysis, standard errors are clustered at the state level to allow for arbitrary correlation of error terms over time within a state, as any effect is likely to take time to be absorbed.

The main coefficients of interest, β_1^p, where p = DIV, PROC, SIT, INT, ISO, measure the average effect of each type of generation restructuring policy on the outcome variable, conditional on the implementation of other policies. We leverage the natural variation resulting from the different timing of the adoption of restructuring policies at the state level to estimate coefficients $\beta 1_1^{DIV}, \beta_1^{PROC}, \beta_1^{SIT}\ and\ \beta_1^{INT}$. On the other hand, β_1^{ISO} is estimated from the staggered creation and expansion of different ISO/RTO. When an individual state adopts a policy or joins an ISO/RTO, all states without such policy in effect or being a participant in ISO/RTO serve as the control group. After adjusted for common shocks and time-invariant differences using fixed effects, we are essentially comparing the average changes in outcomes before and after the policy in restructured states with average changes in outcomes in control states to obtain the estimated effect of implementing a specific type of generation restructuring policy.[168]

Model A will provide an unbiased estimate of β_1^p if the implementation of policy p is uncorrelated with the regression error, conditional on other policies and all control variables mentioned above. This assumption could be violated if, for example, generation restructuring responded to unobserved shocks to variables like changes in consumers' preference or increased energy input costs for power plants which themselves affect renewable energy adoption. Moreover, investment in renewable capacity could drive generation restructuring, as interest groups formed by independent producers in the realm of renewable energy build up and play a more active role in policy making.[169] Finally, power producers may anticipate the adoption of restructuring policies and strategically adjust their investment plans before those policies are actually in effect. To assess the validity of our identifying assumption that policy implementation is uncorrelated with regression error, we construct event study graphs. In particular, we add leads and lags of the policy variables into the regression model, and plot estimates for each

167. We generally follow Kim, Yang, & Urpelainen, *supra* note 12, in our choice of variables to include, and use specifications with and without the control variables to test how sensitive the estimation is to inclusion of additional control variables.

168. This approach ignores the dynamic of producers' responses after restructuring, as it averages across all restructured states and post-restructuring years. Event study figures can shed lights on this, but it is not the focus of our study.

169. *See supra* note 27.

period surrounding policy implementation. Results from event study graphs generally rule out the above scenarios.[170]

To demonstrate the power of our estimation, we provide evidence that there is substantial variation in generation restructuring variables across states and time. Importantly, while one might expect that different types of restructuring policies are grouped or follow particular sequences in implementation across states, there is in fact significant variation in the timing of the adoption of restructuring policies. Table 1 summarizes the status of generation restructuring at the beginning, in the middle, and by the end of the sample period. For each type of generation restructuring, the base case used as the reference level in the regression is shown in bold, and all policies are sorted by their ability to promote market competition in ascending order.

The period of 1990-2018 witnessed substantial changes in policies related to divestiture, procurement, interconnection and ISO/RTO, although less so compared to policies related to siting.[171] As shown in the table, in 1990, most states had no divestiture, procurement or interconnection requirements.[172] In comparison, only 6 states lacked any siting requirement, while more than half of states had the most stringent level of requirement.[173] As for 2018, about half of states had some forms of divestiture or procurement requirement, and about three quarters of states had some forms of interconnection requirement.[174] 48 states had siting requirements in 2018, although the distribution seemed to shift slightly towards less stringency.[175] The average of proportion of generation capacity in ISO/RTO territory goes from zero to about 60%. The proportion of privately-owned vs. publicly-owned capacity remains stable over time, with a typical generation system 75% owned by private entities and 25% owned by public entities.[176] However, one should note that ownership varies a lot across states, with West Virginia 100% owned by private entities and Nebraska close to 100% owned by public entities in 1990 for example.[177]

170. *See infra* Table B1. All of the above scenarios that might undermine our identifying assumption would suggest the existence of differential trends before generation restructuring in the outcomes of the restructured states compared to the control states. For instance, since it is relatively easier to adjust production and investment compared to the enactment of a new policy in response to unobserved shocks to input costs, if unobserved shocks are important, we should observe increases in renewable energy adoption prior to generation restructuring. Likewise, if it is the case that renewable energy drives the adoption of generation restructuring, we should see higher levels of renewable energy penetration prior to generation restructuring. Strategic behavior due to power producer anticipation of future generation restructuring could lead to either higher or lower investment but should be concentrated in the years immediately before policy implementation. On the other hand, if there is no obvious differential trends in pre-restructuring periods, then we can rule out the possibility that unobserved confounding factors other than the policy itself drove the observed change in the outcome variable.

171. *Id.*

172. *Id.*

173. *Id.*

174. *See infra* Table B1.

175. *Id.*

176. *Id.*

177. *Id.*

POLICY NAME	STATES WITH POLICY IN EFFECT			
	1990	2005	2018	All years (proportion)
DIVESTITURE				
• Divestiture prohibited OR permission required to divest	3	6	6	0.1
• **Restructuring inquiry not pursued OR restructuring inquiry rejected/abandoned/appealed**	**47**	**26**	**28**	**0.65**
• Divestiture optional, IOUs restructured (with or without functional separation requirement)	0	13	10	0.17
• Full divestiture ordered	0	5	6	0.09
PROCUREMENT				
• **No requirements found OR Integrated Resource**	**49**	**30**	**25**	**0.68**

Planning (IRP) requirements only				
• Some procurement requirements	1	20	25	0.32
SITING				
• **CPCN and Environmental Certification required**	**26**	**23**	**22**	**0.48**
• CPCN required only	12	15	18	0.29
• Environmental or site approvals only	6	6	8	0.13
• No requirements found	6	6	2	0.11
INTERCONNECTION				
• **No interconnection requirements**	**48**	**36**	**12**	**0.67**
• Some interconnection requirements	2	14	38	0.33
ISO/RTO				
• **No private capacity in ISO/RTO**	**50**	**19**	**11**	**0.54**

• Some private capacity in ISO/RTO	0	31	39	0.46

Table B1: Evolution Of Status Of Generation Restructuring, 1990-2018

Our next set of analyses aims to better understand the relationship between generation restructuring and renewable energy investment under different market and policy conditions. First, we investigate the interaction of key renewable policies (RPS and other renewable energy programs) or retail restructuring with generation restructuring. While we expect that renewable policies would promote renewable energy adoption, wholesale restructuring may amplify their effects by facilitating renewable power providers to take advantage of the policy incentives. Wholesale restructuring might also interact with retail restructuring, particularly in states that include both as part of a broader restructuring program. We examine both of these possibilities by interacting restructuring variables with d_{st}, representing one of the following: an indicator of RPS in effect; cumulative number of renewable incentive programs; and, a dummy variable equal to 1 if the state has retail restructuring in effect. It results in the following model:

$$\begin{aligned} Model\ B\colon\ y_{st} = {} & \beta_1^{DIV} DIV + \beta_1^{PROC} PROC + \beta_1^{SIT} SIT + \beta_1^{INT} INT + \beta_1^{ISO} ISO \\ & + \beta_2^{DIV} DIV\ X\ d_{st} + \beta_2^{PROC} PROC\ X\ d_{st} + \beta_2^{SIT} SIT\ X\ d_{st} \\ & + \beta_2^{INT} INT\ X\ d_{st} + \beta_2^{ISO} ISO\ X\ d_{st} + X_{st}\Gamma + \eta_s + \eta_t + \alpha^s t \\ & + \epsilon_{st} \end{aligned}$$

Second, we are interested in the role of public ownership.[178] On the one hand, publicly owned utilities are largely exempted from restructuring. On the other hand, publicly owned utility systems leave the decision-making over generation to a public process that may not be primarily responsive to costs, at least in comparison to a restructured regulatory system. Therefore, states with substantial publicly owned capacity may see different relationships between generation restructuring, or in general market forces, and investment in renewable energy. Instead, renewable energy investment may correlate with underlying political dynamics in the state, such as the relative strength of environmental groups versus the fossil-fuel industry. To test this, we divide all states into two groups based on their proportion of public-owned capacity at the beginning of the sample, with the median as the cut-off, and estimate effects separately for two subsamples.

178. Since IPP and public ownership are to some extent substitutes, public ownership might also be affected by generation restructuring. However, as noted earlier, publicly-owned systems were mostly created before the era of restructuring began in the 1980s and remain largely untouched, so this variable can be viewed as exogenous in our study.

B. Data

1. Generation Restructuring Policies

In order to assess state-level restructuring policies over time, we gathered state-by-state data for each of the following four restructuring factors: (1) divestiture; (2) electricity procurement; (3) siting; and (4) grid interconnection. For each state, and for each of the four factors, we drew on five databases as starting points: the Energy Information Administration's 2003 restructuring report, the Database of State Incentives for Renewables and Efficiency ("DSIRE"), the American Council for an Energy-Efficient Economy's Interconnection Standards database, OpenEI's Regulatory and Permitting Information Desktop ("RAPID") Toolkit, and reports in the early 1990s from the National Association of Regulatory Utility Commissioners on the status of state generation siting policies in those years.[179] Where feasible, we verified the information in these databases against the corresponding legislative or administrative primary source documents. Where we could not find the corresponding primary source documents, we instead verified the information against additional secondary source documents, usually reports published by regulatory agencies or industry consultants. For each factor, we searched and catalogued all policy changes over time from approximately 1990 through 2018.

We coded each factor as categorical variables with zero as the base case. For divestiture, the base case is no policy or abandonment of restructuring; optional divestiture and mandatory divestiture are respectively weaker and stronger generation restructuring policies; and a prohibition on divestiture is a policy contrary to generation restructuring. For procurement and interconnection, the base case is no policy, and our only other category is some form of policy that is supportive of restructuring. For siting, our base case represents stringent regulation of siting with both CPCN and environmental approval requirements, and all of the other categories involve only some level of governmental restriction on siting.

We assess the extent to which a state's electric grid is incorporated in an ISO/RTO by measuring for each year the proportion of the state's total electricity generating capacity that is provided by privately-owned non-cooperative generators that are within the service area of any ISO/RTO. We measure the service area of an ISO/RTO by the service area of the transmission line owners that are within an ISO/RTO in a given year. We obtained the generation capacity and ownership data from EIA-860; data on ISO/RTO membership was obtained from the ISO/RTO websites.

179. *See* ENERGY INFO. ADMIN., STATUS OF STATE ELECTRIC INDUSTRY RESTRUCTURING ACTIVITY AS OF 2003 (2003), https://www.eia.gov/electricity/policies/legislation/california/pdf/restructure.pdf; NC CLEAN ENERGY TECH. CENTER, *Database of State Incentives for Renewables and Efficiency*, https://www.dsireusa.org (last visited Feb. 17, 2022); AM. COUNCIL FOR AN ENERGY-EFFICIENT ECONOMY, *State and Local Policy Database*, database.aceee.org (last visited February 17, 2022); OPENEI, *Geothermal Power Plant Siting, Construction, and Regulation Overview*, https://openei.org/wiki/RAPID/Roadmap/7.

2. Electricity Market Data

Most outcome and control variables are constructed using information from survey forms administrated by EIA to collect energy data. For renewable electricity capacity, we use EIA-860 ("Annual Electric Generator Report"), EIA-923 ("Power Plant Operations Report") and EIA-861("Annual Electric Power Industry Report"). Information of capacity ownership is obtained from the 2018 December version of EIA-860M ("Monthly Update to the Annual Electric Generator Report"), and we combine the information on the first operation year of each generator to produce a time-varying aggregate measure of ownership at the state level. This approach may create measurement errors if there were changes in ownership during the lifetime of the generator. Ideally, we want to use ownership information documented in each year's EIA-860, but this information is only fully available after 2008. CO2 emission is from EIA-923 and average price from EIA-861.

Data on renewable energy programs and RPS are from DSIRE. We follow Kim *et. al.* to define and construct the cumulative number of renewable programs.[180] Information about retail restructuring comes from a report by Brattle.[181] Population and income data are obtained from Bureau of Economic Analysis.[182] Information about total electrical system energy losses, net import and interstate flow of electricity, and energy consumption by sources is from EIA's State Energy Data System (SEDS).[183]

Table B2 shows summary statics for selected key variables. In our main sample, the average state has about 5% renewable electricity generation and capacity.[184] On average, 23% of capacity is owned by independent power producers.[185]

Variable Name	N	mean	sd	min	max
GENERATION CAPACITY					
Proportion of renewable capacity	1450	0.05	0.07	0.00	0.43
Proportion of IPP capacity	1450	0.23	0.29	0.00	0.99
SELECTED CONTROL VARIABLES					
Cumulative number of renewable energy programs	1450	3.00	2.40	0.00	14.00
RPS policy	1450	0.38	0.49	0.00	1.00

180. *See* Kim, Yang, & Urpelainen, *supra* note 12.

181. J.P. Pfeiffenberger *et al*, *Restructuring Revisited*, PUB. UTIL. FORTNIGHTLY 69 (2007) https://www.brattle.com/wpcontent/uploads/2017/10/7019_restructuringrevisited_pfeif_puf_2007.pdf.

182. United States Bureau of Economic Analysis, https://www.bea.gov (last visited on February 14, 2022).

183. While some SEDS data series come directly from surveys conducted by EIA, many are estimated using other available information.

184. *See supra* Table B1.

185. *Id.*

Retail restructuring	1450	0.24	0.43	0.00	1.00

Table B2: Summary Statistics

REFORM OF LEGAL AND REGULATORY IMPEDIMENTS TO FOREIGN INVESTMENT AND CROSS- BORDER ENERGY TRADING BY NEPAL AND OTHER SOUTH ASIAN NATIONS

Madhab Raj Ghimire, Deepshikha Wagle, Sukhyati Malla, Brian Barkdoll, Narayan Ghimire[*]

Synopsis: Nepal, endowed with water resources, has vast potential for hydropower development, including through foreign direct investment (FDI) and cross-border trade. At the same time, however, Nepal is facing an energy crisis due to the shortage of readily available power and petroleum products. This article explores options to develop Nepal's energy sector through two main theses: (1) foreign energy investment in Nepal may be improved by removing regulatory obstacles, including resolving the inherent tensions between federal, provincial, and local legal regimes; and (2) despite continuing challenges, bilateral and multilateral agreements in South Asia may continue to contribute to increased interest in foreign direct investment and cross-border energy trade.

First, this article examines the tension between the current federal energy regulatory regime in Nepal and the sometimes conflicting provincial and local laws and regulations. These tensions are exacerbated by the lack of an institutional mechanism to govern the allocation of responsibilities between national, provincial, and local governments. Specifically, the authors recommend reforms that would minimize these conflicts by strengthening national authority over licensing, tariff, and fee determinations, preventing anti-competitive practices, and

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improving compliance monitoring, consumer protection, and capacity building. Nepal is in a much more politically stable place currently as compared to the early 2000s during the Maoist insurgency period, and the power generation business market in Nepal is potentially lucrative, so much so that beginning in 2015, Nepal started attracting foreign direct investment. Continuing political stability, combined with the implementation of consistent legal and regulatory frameworks for energy sector development, will allow Nepal to continue attracting investors in the future.

Secondly, this article aids potential investors in making informed decisions about how the energy market in Nepal and cross-border trade between Nepal and other countries operates. Nepal is surrounded by two of the most populous nations in the world, China to the north, and India to the east, west, and south. Expanding economies and rising population in Nepal and its surrounding countries have driven growing demand for more reliable and sustainable supplies of electricity in the South Asian region. Nepal's hydropower resources present significant opportunities for cross-border electricity trade. But challenges exist, including how current regional frameworks fail to address conflicting national laws adequately, the implications of uneven negotiating power between countries in the region, and the difficulty of implementing reforms in developing countries like Nepal.

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I. INTRODUCTION

Nepal is rich in hydropower resources, with a development potential of about 83,000 Megawatts (MW) and a commercially exploitable hydropower generating potential of about 42,000 MW.[1] In total, Nepal possesses 6000 rivers most of which flow from the Himalayas, including rivulets and tributaries offering multi-dimensional uses including hydropower development. Perennial rivers have an estimated annual runoff of approximately 170 billion m^3 that flow from steep-gradient and rugged topography with an estimated potential for supporting 45,610 MW of hydropower generation, which is equivalent to 50% of the total theoretical potential.[2] However, due to a combination of several major challenges present in the energy sector, as of 2016, the country only had a total-installed hydropower generation capacity of 13,853 MW,[3] which is less than 2% of the country's commercially exploitable hydropower generation potential.[4] While hydroelectric imports from India supplement Nepal's low domestic generation

1. Asian Development Bank, *Technical Assistance for the South Asia Economic Integration Partnership - Power Trading in Bangladesh and Nepal (Subproject 1), Manila (TA 8658-REG)* (2021), https://www.adb.org/projects/45396-009/main.

2. Ramesh Prasad Bhatt, *Hydropower Development in Nepal - Climate Change, Impacts and Implications* (2017), https://www.intechopen.com/chapters/53350.

3. Prithivi Man Shrestha, *Once Power-starved, Nepal now aims to export electricity*, THE KATHMANDU POST (Aug. 10, 2021), https://kathmandupost.com/money/2021/08/10/once-power-starved-nepal-now-aims-to-export-electricity.

4. NEPAL ENERGY SECTOR ASSESSMENT, STRATEGY, AND ROADMAP 5-6 (Asian Development Bank, 2017).

capacity, Nepal's current aggregate energy supply is inadequate to meet the ever-increasing demand of electricity by the nation's residential and industrial sectors.[5] Outside of hydropower, Nepal relies on petroleum imports from countries including India to meet 11 percent of its energy needs, a number expected to rise to 12 percent by 2035, if there are no changes in current law.[6] Biomass, oil products, coal, hydro, and electricity have become Nepal's main sources of primary energy.[7] However, these sources of energy are insufficient to meet the demand for energy in Nepal, and this energy shortfall has seriously constrained economic and social development in the country.[8]

II. FOREIGN DIRECT INVESTMENT (FDI) IN NEPAL'S ENERGY SECTOR HAS BEEN LIMITED BY NUMEROUS CHALLENGES, INCLUDING POLITICAL UNCERTAINTY AND A LACK OF SEAMLESS FUNCTIONING OF FEDERAL, PROVINCIAL, AND LOCAL AUTHORITIES

Foreign energy investment in Nepal has been limited by regulatory challenges. These include inefficiencies and unresolved tensions inherent in the smooth and seamless functioning of federal, provincial, and local legal and regulatory regimes that discourage FDI in Nepal's energy sector. Implementation of targeted regulatory reform may reduce these tensions and broaden investment opportunities in Nepal.

A. Overview of Nepal's Energy Investment Regime

1. Historical and Current Status of Foreign Direct Investment in Nepal

Nepal's energy sector would benefit from additional FDI investment, but historically, potential investors have been wary of investing in a country with an unstable and conflict-driven political environment. During, and immediately after, the Maoist political conflict in 2004,[9] Nepal had negative inflow of FDI.[10] A gradual improvement in political stability through 2014 led to a sharp increase of the flow of FDI from 2015 to 2018.[11] Nepal's more recent focus on and commitment towards attracting FDI was illustrated at the Investment Summits[12] in

5. *Id.*

6. *Id.*

7. *Id.*

8. NEPAL ENERGY SECTOR ASSESSMENT, STRATEGY, AND ROADMAP, *supra* note 4, at 9.

9. The Comprehensive Peace Accord (CPA) declared that the conflict period started in 1996 and ended 2006. This CPA has been reached between the Nepal Government and the CPN (Maoist) with a commitment to transform the ceasefire between the Nepal Government and the CPN (Maoist) into long-term peace; *see* Comprehensive Peace Accord, Nepal-Communist Party of Nepal (Maoist), Nov. 22, 2006, https://peacemaker.un.org/nepal-comprehensiveagreement2006.

10. Rajesh Bastola, *Investment trends in Nepal*, THE KATHMANDU POST (Mar. 5, 2020), https://kathmandupost.com/columns/2020/03/05/investment-trends-in-nepal.

11. *Id.*

12. The Investment Summit, hosted by Nepal, acts as a platform for investors to understand the investment environment and opportunities in Nepal through prominent national and international speakers, dignitaries, sector-specific experts, and high- ranking government representatives; GOVERNMENT OF NEPAL, NEPAL INVESTMENT SUMMIT 2019 3, https://my.nepalembassy.gov.np/wp-content/uploads/2019/02/NIS2019.pdf.

2017 and 2019.[13] Also, in an effort to address the absence of concrete laws in Nepal regarding FDI, Nepal enacted the Foreign Investment and Technology Transfer Act (FITTA) of 2019,[14] which incorporated the major principles of most-favored-nation treatment, limitations on expropriation, and an investor-focused dispute settlement mechanism. Introduction of a one-stop service center[15] for foreign investors to overcome administrative hurdles further helped to create a favorable environment for investment. In 2018, FDI in Nepal amounted to $161 million.[16] In the World Bank 'Doing Business' Report of 2019, Nepal ranked 94th among 190 countries for having a favorable environment for foreign investment.[17]

2. Challenges Facing Foreign Direct Investment in Nepal

Although there is great potential market for FDI investment in the energy sector in Nepal, there are several significant hurdles that must be overcome. First, FDI in Nepal has been hampered by infrastructure limitations and other political challenges. According to the World Bank, "Nepal ranks 130th out of 190 countries in terms of infrastructure availability -- the worst in South Asia."[18] The lack of adequate energy infrastructure prevents investor access to rural areas, making energy investment in this sector less attractive.

Second, lack of political commitment, difficulties in transferring profits of investment to the investors' home countries, lack of transparency, and endemic corruption are some of the key factors that discourage foreign investors in Nepal.[19] Corruption laws limit the operations of foreign banks, the repatriation of profits, currency exchange facilities, and provide for the government's virtual monopoly over certain sectors of the economy, such as electricity transmission.[20] All these factors act to frustrate greater foreign investment in Nepal.[21] Due to the

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13. Editorial, *Investment Summit Progress Report Card*, THE KATHMANDU POST (Apr. 21, 2019), https://kathmandupost.com/national/2019/04/21/investment-summits-progress-report-card-48-applications-for-31-projects.

14. The Foreign Investment and Technology Transfer Act, 2019 (2075) (Act No. 34/2075).

15. The Industrial Enterprises Act, 2020, has provisions for establishment of a One Stop Service Center, through which foreign investors can avail themselves of the full range of services provided by the various government entities involved in investment approvals, including the Ministry of Industry, Commerce, and Supplies (MOICS), the Labor and Immigration Departments, and the Central Bank; The Industrial Enterprises Act, 2076 (2020) (Act No. 19/2076) § 37.

16. Prithivi Man Shrestha, *Why has Nepal failed to attract enough foreign direct investment?*, THE KATHMANDU POST (Nov. 7, 2019), https://kathmandupost.com/money/2019/11/07/why-has-nepal-failed-to-attract-enough-foreign-direct-investment.

17. Sujan Dhungana, *Nepal Rank's 94th in Doing Business Index*, THE HIMALAYAN TIMES (Oct. 2019), https://thehimalayantimes.com/business/nepal-ranks-94th-in-doing-business-index.

18. World Bank Group, *Nepal: Systematic Country Diagnostic* 10 (Feb. 2018), https://documents1.worldbank.org/curated/en/361961519398424670/pdf/Nepal-SCD-Feb1-02202018.pdf.

19. Hari Bansha Jha, *Nepal's FDI challenges* (2020), https://www.orfonline.org/expert-speak/nepals-fdi-challenges/.

20. *Id.*

21. Republica, *US State Department sees significant barriers to investment in Nepal* (2020), https://myrepublica.nagariknetwork.com/news/us-state-department-sees-significant-barriers-to-investment-in-nepal/?categoryId=81.

dimming profit outlook for hydropower, two foreign companies from China and Norway pulled out of two hydropower projects in the span of four years (2016-2019).[22] Historically, projects that have been abandoned by foreign investors have remained abandoned or have been downsized significantly when taken over by domestic interests.[23]

Furthermore, as Nepal has undergone major changes resulting from the introduction of federalism in 2015, legal and regulatory tensions among the three tiers of government in regulating the energy industry have discouraged direct foreign investment in Nepal.

Significantly, provincial and local governments are not yet firmly established.

Federal regulation over the energy sector remains the most relevant for foreign investments and businesses.[24] The Industrial Enterprises Act strictly prohibits the nationalization or expropriation of industry registered under the Act.[25] Nepal, moreover, does not have a history of expropriations: there have been no cases of nationalization in Nepal, nor are there any official policies that suggest expropriation should be a concern for prospective investors.[26] The Foreign Investment and Technology Transfer Act also enables foreign investors to repatriate all forms of investment after paying all applicable taxes.[27]

3. Constitutional Provisions Establishing Federalism in Government

A full understanding of the legal tensions between Nepal's federal, provincial and local level governments requires an understanding of Nepal's federalism structure. Nepal had been practicing a unitary form of government until federalism was introduced in 2015.[28] Nepal's Constitution introduced a three-tier structure of government – federal, provincial, and local – with each level having power to enact laws and providing each with the responsibilities, revenues, and expenditures intended to enable each tier to perform its duties efficiently and effectively.[29]

The Constitution of Nepal is divided in various Parts, Articles and Schedules. Separate powers have been allocated to federal,[30] provincial,[31] and local

22. Deepak Adhikari, *Nepal Power Export Plans in Doubt as India Reviews Options* (2019), https://asia.nikkei.com/Politics/International-relations/Nepal-power-export-plans-in-doubt-as-India-reviews-options.

23. *Id.*

24. U.S. Dep't of State, *2020 Investment Climate Statements: Nepal* (2020), https://www.state.gov/reports/2020-investment-climate-statements/nepal/.

25. Industrial Enterprises Act, 2076 (2020) (Act No.19/2076) art. 34.

26. ELECTRICITY REGULATORY COMMISSION RULES, 2018, 18 (Sept. 6, 2018), http://erc.gov.np/storage/listies/April2020/erc-rules-2018.pdf.

27. Foreign Investment and Technology Transfer Act, 2019 (2075) (Act No. 34/2075) § 20(2).

28. Regmi K, Upadhyay M, Tarin E. et al., *Need of the Ministry of Health in Federal Democratic Republic of Nepal*, JNMA J NEPAL MED ASSOC. (2017), https://pubmed.ncbi.nlm.nih.gov/28746331/.

29. Constitution of Nepal 2015, art. 59 § 1.

30. Constitution of Nepal 2015, Schedule 5.

31. Constitution of Nepal 2015, Schedule 6.

levels[32] in the respective Schedules 5, 6, and 8; concurrent power between provincial and federal governments has been allocated in Schedule 7[33]; and concurrent power among all three tiers has been allocated in Schedule 9.[34] The federal parliament passed the Act Relating to the Management of Interrelationship and Coordination between the Federation, Province, and Local Level.[35] The Act was formulated in accordance with Part 20 of the Constitution to maintain relations among the three tiers of the government based on the principles of cooperation, coexistence, and coordination.[36] This Act provides greater clarity of the functional responsibilities of the three tiers of the government.

As an example of concurrent power sharing, the power to provide services such as electricity, water supply, and irrigation is provided on a power sharing basis to all three tiers of government.[37] The federal level is responsible for the formation of policies relating to conservation and multiple uses of water resources.[38] The provincial government has power over province-level generation, transmission, and distribution of electricity, irrigation and water supply services, navigation, and water resources infrastructure development.[39] In this instance, the power reserved to the provincial government overlaps with the power of the federal level in regards to "multiple uses of water resources."[40] The local level has power over small hydropower, water supply to local communities, and irrigation, and is mostly responsible for access and distribution of water resources.[41] The major challenge of federalism is the implementation of federalism principles like equal allocation and efficient mobilization of resources, while formulating laws and policies in all three tiers that address the specific needs of each level of government in a manner that lessens contradictions between the laws as much as possible.

4. Legal Provisions and Contradictions

Contradictory laws among the three tiers pose a major challenge in the effective implementation of federalism, thereby creating ambiguity in the application of laws. The Draft Water Resources Act (hereinafter, the Draft Act) illustrates a recent example of tensions between the various levels of government.[42] The Draft Act sets out the distribution of power among the three tiers of gov-

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32. Constitution of Nepal 2015, Schedule 8.

33. Constitution of Nepal 2015, Schedule 7.

34. Constitution of Nepal 2015, Schedule 9.

35. *Id.*

36. *Id.*

37. Constitution of Nepal 2015, Schedule 9.

38. Constitution of Nepal 2015, Schedule 5.

39. Constitution of Nepal 2015, Schedule 6.

40. Manohara Khadka et al., *Understanding barriers and opportunities for scaling sustainable and inclusive farmer-led irrigation development in Nepal*, CIMMYT (2021), https://repository.cimmyt.org/bitstream/handle/10883/21683/64317.pdf?sequence=1&isAllowed=y.

41. Constitution of Nepal 2015, Schedule 8.

42. Draft Water Resources Bill 2074, https://www.moewri.gov.np/storage/listies/August2020/water-resources-bill-2077.pdf.

ernment.[43] The Draft Act provides that the power and responsibility for the development, implementation, and management of water-resources-related projects is to be allocated to the federal government in the cases of large and inter-provincial projects, to the provincial government for medium or inter-local level projects, and to the local level for other projects.[44] Under the Draft Act, a large project means a hydropower generation project exceeding a capacity of 100 MW, and a medium project consists of a hydropower generation project ranging from 1 MW up to 100 MW.[45] By implication, the local level has authority for projects *below* 1 MW,[46] directly contradicting the local level's power over hydropower projects of 3 MW as expressly set by the National Planning Commission.[47] Further complicating jurisdictional responsibility, the National Planning Commission Standard of 2018 on distribution and classification of project development for federal, provincial, and local levels, states that: both hydro and solar energy projects of more than 20 MW fall under federal jurisdiction; projects having a capacity of 3 to 20 MW are under the jurisdiction of the province; and projects less than 3 MW are under the jurisdiction of the local government.[48] This is not the only source of confusion. The Local Government Operation Act of 2017 Act states that the power of the Village Committee and Municipal Assembly to plan, set standards, inspect, and implement a hydroelectricity project is limited to 1 MW only,[49] which contradicts what has been provided in the National Natural Resources and the Fiscal Planning Directive. Plainly, greater harmonization of jurisdictional lines of authority needs to occur.

Further contradiction exists. The Local Alternative Energy Development Related Directive of 2017 has been formed under the provision of the Local Governance Operation Act, 2017, and mandates that the power of local level government to produce, survey, and transmit electric power is limited to 1 MW.[50] Subsequently, however, the Alternative Energy Development Committee Order, 1996,[51] was given the authority and directed to develop alternative energy up to 10 MW.

Additionally, the Draft Electricity Bill of 2019 provides the local government power to produce, distribute, or transmit electricity of development projects having a capacity up to 3 MW and the provincial level government to have pow-

43. Manohara Khadka et al., *supra* note 40.

44. Draft Water Resources Bill 2074 § 20(4), https://www.moewri.gov.np/storage/listies/August2020/water-resources-bill-2077.pdf.

45. *Id.*

46. *Id.*

47. National Planning Commission (NPC) Standard on Distribution and Classification of Project Development for Federal, Province and Local level (2019), https://npc.gov.np/images/category/Mapadanda,_2076.pdf.

48. *Id.*

49. Local Government Operation Act § 3(11) (2017), www.moljpa.gov.np/wp-content/uploads/2018/02/.pdf.

50. LOCAL ALTERNATIVE ENERGY DEVELOPMENT RELATED DIRECTIVE: BACKGROUND (2018), https://www.mofaga.gov.np/model-law/133.

51. Alternative Energy Development Committee Order § 2(b) (1996), https://www.aepc.gov.np/uploads/docs/l-uu-aa-1543137949.pdf.

er over projects having a capacity from 3 MW to 20 MW.[52] Projects above 20MW are subject to federal jurisdiction.[53] This draft bill is consistent with this balanced and distinct power allocation among federal-provincial-local levels. However, the Province Electricity Act of Province 1 states that electricity generation projects having a capacity above 1 MW fall under the jurisdiction of provincial governments under federal law.[54] It further states that for projects having a capacity of less than 1 MW, the province may assert jurisdiction over the project or, upon the request of local level government, hand over the project for construction and operation to the local government.[55] Thus, the Province Act and the Electricity Bill are contradictory.

The many contradictions that exist among the relevant laws and jurisdictional authority of the three tiers show the critical need for harmonization in order for federalism to function properly and efficiently in Nepal. Confusion will also likely seriously frustrate meaningful FDI investment.

5. Need for Coordination by Government and Harmonization of Laws

The multi-dimensional nature of water energy resource development in Nepal makes hydropower legislation complicated. Because the Constitution requires legislation at all three tiers of Nepal's federal system, hydropower policies across the three tiers must avoid contradictions for projects to succeed.[56] Provincial governments play an important role and act as a bridge between the federal and local level.[57] Local governments then formulate their laws to be consistent with provincial laws. Consistent laws, in turn, ensure the strengthening of interrelationships among the governmental tiers. Delays in legislation in the other tiers have crippled potential development at the local level because local levels cannot work in isolation and must coordinate with the other tiers of government. Sharing of costs and revenues between the federal, provincial, and local governments must also be negotiated carefully.

Third party institutional assessment of law-making bodies is required for timely formulation of laws and effective implementation of projects. It is extremely important for law-making bodies of the respective tiers to consider the possible conflicts and contradictions that may arise among the three tiers and formulate laws to address possible conflicts.

52. Draft Electricity Bill 2076 § 3 (2021), https://www.moewri.gov.np/storage/listies/July2020/electricity-bill.pdf.

53. Draft Electricity Bill 2076 § 8 (2021), https://www.moewri.gov.np/storage/listies/July2020/electricity-bill.

54. Electricity Act 2076 § 3(1) (2021), http://moial.p1.gov.np/post/pa-ratha-sha-va-thha-ta-aina-1.

55. AASHISH PRADHAN, ELECTRICITY PROJECT LICENSING IN NEPAL- EXPECTED CHANGES IN THE MANDATES OF ELECTRICITY ACT AND TRANSITION OF RESPONSIBILITIES 6 (2021).

56. Constitution of Nepal 2015, Part 5.

57. DEMOCRACY RES. CTR. NEPAL, THE INTERRELATIONSHIP BETWEEN THREE LEVELS OF GOVERNMENTS IN NEPAL'S FEDERAL STRUCTURE: A STUDY REPORT 21 (2020), https://www. democracy resource. org/wp-content/uploads/2020/10/Inter-Government-Relation_EngVer_13October2020.

B. The Continuing Development of Legal, Regulatory and Institutional Reforms May Encourage Foreign Investment in Nepal's Energy Sector

1. Principles of Cooperation, Coexistence, and Coordination Must Advance to Avoid Conflicts and Improve Coordination Among the Different Tiers of Government

Article 232 of the Constitution provides that the three spheres of the government in Nepal (federal, provincial, and local) are not hierarchically related; rather, their relationship should be based on the "principles of cooperation, coexistence, and coordination."[58] However, because Nepal has limited experience with federalism, all three levels of government face the burden of transforming the legal, administrative, political, and fiscal structures previously established under the unitary system into a federal system.[59] Uncertainties and ambiguities exist regarding the distribution of resources, jurisdiction of each level of government, potentially overlapping legislative powers, and the administrative management of provincial and local governments.[60] Although each level of government has generally independently exercised its exclusive powers without major complications, resolution of conflicts relating to their concurrent powers has become one of the most significant challenges. Improved cooperation and coordination is clearly needed to avoid such conflicts and tensions between the different tiers of government, and the resulting efficiencies in governance may in turn attract more investment into the country.

One of the essential components of these principles is the interdependence of the three tiers of governance while keeping intact the distinctiveness of each tier. Each tier of the government is considered to be autonomous and independent, and it is the constitutional duty of the tiers to respect each other's powers, functions, and institutions.[61] The cooperative federal system adopted by Nepal represents the basic values of both the 'shared rule' and 'self-rule' in the government structures and institutions. This governing model is premised upon partnership and collaboration among the three tiers of government where each tier has a specific role to fulfill and, hence, promote constructive relationships with the other tiers.[62] Laws at the sub-national level are supposed to respect and be consistent with the principles, institutions, and processes of cooperative federalism; the federal government is also expected to respect the constitutional principles of self-rule so as not to influence or override functions assigned to sub-national levels.[63] This combination of interdependence and distinctiveness, in turn, is intended to play a significant role in avoiding conflicts between the three tiers of government.

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58. *Id.* at 1.

59. *Id.*

60. *Id.*

61. Federation, Province and Local Level (Coordination and Interrelation) Act, Section 4 (2020) (Nepal).

62. Mukti Rijal, *Issues of Cooperative Federalism*, THE RISING NEPAL (Mar. 5, 2020), https://risingnepaldaily.com/opinion/issues-of-cooperative-federalism.

63. *Id.*

To manage the relationships between the three tiers of government under the principles of coexistence, coordination, and mutual cooperation, Nepal has recently enacted the Federation, Provincial, and Local Levels (Coordination and Interrelation) Act.[64] The Act sets forth the matters to be considered by the federal, provincial, and local levels of government while formulating law or policy under the exclusive and concurrent jurisdiction.[65] Consistent with the principles of cooperative federalism, the Act has demarcated the matters to be governed by the federal, provincial, and local level and requires each tier of the government to avoid encroaching upon the exclusively assigned functions of other tiers.[66]

Similarly, provisions within the Act relating to coordination and consultation, project planning, implementation, and collaboration have provided increased clarity and predictability for the tiers of government. The Act establishes a National Coordination Council[67] in order to manage the coordination and relationships between the three tiers of government. The Act also establishes the Provincial Coordination Council[68] in each province for coordinating relationships between provincial and local levels or between local levels in more than one district within a province, and the District Coordination Committee[69] at each district for coordinating between local levels in the district, regulating developmental work, and coordinating between offices of the federal and provincial governments in the district and the local levels. Although the Act is newly enacted and yet to be tested for effectiveness, the Act may help direct Nepal towards the path of economic prosperity by making it more hospitable and rewarding for investment.

2. Electricity Regulatory Commission as an Independent Regulator Established to Show Prospective Investors an Effectively Regulated System Operated With Good Governance and Competitive Market:

The Energy Regulatory Commission[70] was established to maintain balance between the demand and supply of electricity by making the generation, transmission and distribution of electricity[71] subject to oversight – creating a transparent electricity market, regulating electricity tariffs, providing consumer protection and making electricity service safe, reliable and accessible to all.

In the context of Nepal's energy sector, where competition exists at all or at least at some level of activities (generation, operation, transmission, distribution, trading), a well-defined regulatory framework legally backed up by the powers

64. Federation, Province and Local Level (Coordination and Interrelation) Act, Preamble (2020) (Nepal).

65. *Id.*

66. *Id.* at 6.

67. *Id.* at 11.

68. Federation, Province and Local Level (Coordination and Interrelation) Act, Section 24 (2020) (Nepal).

69. *Id.* at 15-16.

70. ELEC. REGULATORY COMM., FUNCTIONS, https://erc.gov.np/pages/functions?lan=en.

71. NEPAL GAZETTE, ELECTRICITY REGULATORY COMMISSION ACT, 2074 1 (2017), https://erc.gov.np/storage/listies/April2020/erc-act-2017-english.pdf.

of supervision and oversight serves as an essential tool to ensure fair competition, limit market abuse, and protect the rights and interests of all the stakeholders. Governmental oversight of different aspects of energy market regulation, such as in the areas of licensing, tariff and fees determination, prevention of anticompetitive practices, compliance monitoring, establishment of performance norms and consumer protection will serve to improve predictability for consumers and investors. Building the capacity of the Commission to perform these functions will also increase confidence in the Commission as a reliable institution.

The continuing development and strengthening of the Electricity Regulatory Commission will provide certainty on major regulatory matters. Increased effectiveness of the Electricity Regulatory Commission can assist in reducing the gaps that can arise under Nepal's federal system, which will aid in attracting additional FDI. Greater clarity in some of the major regulatory powers, functions and duties of the Electricity Regulatory Commission has made it a vital part of institutional reform in the energy sector in Nepal that is anticipated to bring about needed regulatory reforms that will help to attract FDI in Nepal.

The Grid Code and Distribution Code for electricity service is formed, executed, and monitored by the Electricity Regulatory Commission, which regulates the electric grid's connection to the transnational distribution system and the international level grids.[72] The tariff establishing regulated services rates is determined by the Electricity Regulatory Commission based on an application submitted by the distribution licensee.[73] The Electricity Regulatory Commission issued the Electricity Tariff Fixation Directive in 2019, specifying the principles under which a tariff is determined.[74]

Transmission and distribution charges (wheeling charges) are also set by the Commission.[75] The Commission conducts a public hearing prior to deciding on matters relating to fixation of electricity tariffs and power purchase/sales rates, fixation of transmission charges and power trading in accordance with the methods, procedures, and format specified by the prevailing laws and by the Electricity Regulation Commission's past decisions.[76] The Electricity Regulatory Commission has also issued the Public Hearing Operation Directive of 2020[77] to make the work of public hearings conducted by the Commission simple, systematic and uniform, and to ensure the right of stakeholders to information and the

72. *Id.* at 10.

73. *Id.* at 11; *See also* ELECTRICITY REGULATORY COMMISSION RULES, 2018, 4 (Sept. 6, 2018), http://erc.gov.np/storage/listies/April2020/erc-rules-2018.pdf.

74. MYREPÚBLICA, ELECTRICITY REGULATORY COMMISSION PROPOSES NEW DIRECTIVE FOR ELECTRICITY TARIFF, (2019), https://myrepublica.nagariknetwork.com/news/78780/.

75. *See* NEPAL GAZETTE, *supra* note 71, at 11.

76. ELECTRICITY REGULATORY COMMISSION RULES, 2018, 18 (Sept. 6, 2018), http://erc.gov.np/storage/listies/April2020/erc-rules-2018.pdf.

77. Electricity Regulatory Commission Act, 2018 (Nepal). *See also* ELECTRICITY REGULATORY COMMISSION RULES, 2018, 8 (Sept. 6, 2018), http://erc.gov.np/storage/listies/April2020/erc-rules-2018.pdf.

right to a fair, fair hearing as per the Act's[78] mandate to implement as binding instrument.

The Electricity Regulatory Commission is empowered to make provisions for competition in the electricity tariff rate over the purchase and sale rate of the electricity and subsequently protect the interest of the consumers.[79] The Nepal Electricity Authority (NEA) is a state-owned, vertically integrated utility that is responsible for generation, transmission, and distribution of electricity in the country along with the development and operation of the national grid.[80] The Commission's recent enforcement of its Consumer Tariff Directive of 2019[81] aims to curb NEA's monopoly power and ability to unilaterally revise tariffs. It turned back NEA's tariff hike proposal, asking the utility to come up with a better justification consistent with the criteria set forth in the Directive.[82] Previously, NEA-would revise its tariffs unilaterally, subject only to the non-binding recommendation of the now defunct Electricity Tariff Fixation Commission.[83] The Electricity Regulatory Commission Act of 2017 gave the Commission power to order changes to NEA's tariff and establish regulations governing the trading of. electricity.[84] Due to the lack of multiple buyers in the market, the Act has also empowered the Commission to maintain a competitive environment over the purchase and sale rates of electricity and to prevent NEA from exercising monopoly power over the sellers of electricity.[85] To this end, the Electricity Regulatory Commission has issued the 'Directive for Merger, Purchase of Shares, Purchase, Sale or Transfer of Infrastructure, Acquisition or Takeover Licensees of 2020'[86] for facilitating merger and acquisition between/among Licensees.

The Electricity Regulatory Commission also regulates and limits the ability of any company or institution licensed to carry out functions related to electricity generation, transmission, distribution, or trade to issue or sell securities.[87] The working capacity of the of applicant for license to be evaluated as per prescribed standards.[88] The Electricity Regulatory Commission also sets and implements the Code of Conduct to be adhered to by the licensed parties, including integrat-

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78. *Id.*

79. *See* NEPAL GAZETTE, *supra* note 71, at 12.

80. Nepal Electricity Authority Act, 2041, (1984) (Nepal).

81. CONSUMER TARIFF DIRECTIVE OF 2019, https://erc.gov.np/storage/listies/April2020/consumer-tariff-directive-2076.pdf.

82. Rajesh Khanal, *NEA Mulls 15% Power Tariff Hike*, MYREPUBLICA (Nov. 14, 2019, 7:35 AM), https://myrepublica.nagariknetwork.com/news/nea-mulls-15-power-tariff-hike/.

83. Prahlad Rijal, *Regulatory Body Rejects Nepal Electricity Authority's Tariff Proposal*, THE KATHMANDU POST (Nov. 12, 2019), https://kathmandupost.com/money/2019/11/12/regulatory-body-rejects-nepal-electricity-authority-s-tariff-proposal.

84. *See* NEPAL GAZETTE, *supra* note 71, at 11.

85. *Id.* at 12.

86. DIRECTIVE FOR MERGER, PURCHASE OF SHARES, PURCHASE, SALE OR TRANSFER OF INFRASTRUCTURE, ACQUISITION OR TAKEOVER (2020), https://erc.gov.np/storage/listies/August2020/merger-acquisition-transfer-related-directive-2077.pdf.

87. *See* NEPAL GAZETTE*, supra* note 71, at 12.

88. *Id.* at 13

ing internal controls, accounting systems, and auditing methods for licensees.[89] The Commission provides essential directives to amend the standards in order to maintain good governance by licensees.[90]

The Commission inspects and monitors licensees' compliance with applicable laws, and is entrusted with the power to impose fines for non-compliance.[91] If required, the Commission gives orders and directives to the relevant to licensee holder, pursuant to a report prepared and submitted by an officer or employee of the Commission[92] to resolve non-compliance issues.

The Commission also has the broad authority to resolve any electricity-related disputes between the licensees, including compensation claims.[93] The Commission is authorized to exercise hearing powers, including calling parties before the Commission to provide statements or other information, questioning witnesses, ordering the submission of documents by any Nepal governmental body or public institution, and examining proofs.[94]

3. Unbundled Structure of Nepal Electricity Authority (NEA)

The Nepal government has recognized that the Nepal Electricity Authority (NEA) must be unbundled to improve efficiency through competition and commercialization.[95] -The draft Electricity Bill[96] of 2020 (Draft Bill) has proposed transforming the electricity industry by creating restrictions on vertically integrated entities.[97] Under the Draft Bill, an entity currently undertaking more than one of each of the service responsibilities pertaining to generation, transmission, and distribution of electricity must form different entities to carry out the various responsibilities three years after the act becomes effective.[98] Unbundling pursuant to the Draft Act is expected to pave the way for institutional reform in the power sector by reducing inefficiencies and promoting competition at a time when the country has experienced tremendous growth in the private power sector. In the meantime, and in anticipation that the Draft Bill will become law, the NEA has already internally unbundled and restructured itself into three major segments: generation, transmission and substation services, and distribution and consumer services.[99]

The Commission determines the terms and conditions of the tariff and regulates both NEA's sales and purchases of electricity.[100] Thus, it reviews and regu-

89. *Id.*

90. *Id.*

91. *See* NEPAL GAZETTE*, supra* note 71, at 14.

92. *Id.*

93. *Id.*

94. *Id.*

95. PRIYANTHA WIJAYATUNGA, ENERGY DIV., TECHNICAL ASSISTANCE COMPLETION REPORT (2009), https://www.adb.org/sites/default/files/project-document/60376/37196-012-nep-tcr.pdf.

96. Draft Electricity Bill, 2076 (2021).

97. *Id.* at § 13.

98. *Id.*

99. NEPAL ELEC. AUTH., ABOUT US, *https://www. nea. org. np/aboutus.*

100. *See* NEPAL GAZETTE, *supra* note 71, at 11.

lates the terms of Power Purchase Agreement (PPA) between NEA and its suppliers and also determines the applicable transmission and distribution fees (wheeling charges).[101] Additionally, NEA released its first comprehensive corporate development plan for the utility and the[102] overall energy sector. This Plan sets out much needed transmission and distribution reforms by providing greater clarity and certainty for the NEA, investors in electricity generation, development partners, and electricity consumers.[103]

III. BILATERAL AND MULTILATERAL AGREEMENTS IN SOUTH ASIA HAVE CONTRIBUTED TO INCREASED INTEREST IN FOREIGN DIRECT INVESTMENT AND CROSS-BORDER ENERGY TRADE

Bilateral and multilateral energy agreements in the South Asian Region have been formed, which have contributed to increased interest in FDI. However, they remain cumbersome and must be reformed to allow for more efficient cross border energy exchange.

A. There are Increasing Opportunities For Cross-Border Trade and Regional Collaboration in Energy Investment

1. Needs, Benefits, and Prospects of Cross-Border and Regional Energy Trade in South Asia

Electricity deficits suffered by many of the South Asian countries, heightened demand for electricity, and a mismatch between seasonal availability have resulted in increased opportunities for cross-border electricity trade in the region.[104] Diverse natural resources ranging from large coal reserves in India, gas reserves in Pakistan and Bangladesh, hydropower potential in Nepal and Bhutan, and alternative resources (including solar and wind) in India, the Maldives, and Sri Lanka are broadly available in the region.[105] While countries like Nepal and Bangladesh currently have insufficient generation resources to meet their domestic power demand throughout the year, countries like India and Bhutan have a surplus of power generation sources available.[106] Power generation variations also arise in each country as a result of weather differences and each country's ability to respond to their domestic energy needs in these circumstances is unique. For example, in Nepal and Bhutan, water sources freeze during winter - resulting in a reduction of hydropower generation, while during the same period

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101. *Id.*

102. ASIAN DEV. BANK, PROPOSED LOAN NEPAL: ELECTRICITY GRID MODERNIZATION PROJECT 1 (2020), https://www.adb.org/sites/default/files/project-documents/54107/54107-001-rrp-en.pdf.

103. *Id.* at 5-6.

104. 38 PRIYANTHA WIJAYATUNGA ET AL., ASIAN DEV. BANK, CROSS-BORDER POWER TRADING IN SOUTH ASIA: A TECHNO ECONOMIC RATIONALE 1 (2015), https://www.adb.org/sites/default/files/publication/173198/south-asia-wp-038.pdf.

105. 19 PRIYANTHA WIJAYATUNGA & P.N. FERNANDO, ASIAN DEV. BANK, AN OVERVIEW OF ENERGY COOPERATION IN SOUTH ASIA 2 (2013), https://www.adb.org/sites/default/files/publication/30262/overview-energy-cooperation-south-asia.pdf.

106. *See id.* at 2, 7.

of time, in India the domestic power demand is lower enabling it to export its excess generation to hydro-dependent countries.[107] India is one of the most densely populated countries in the region and faces difficulties in planning for new large hydropower plants without risking large-scale population displacement and ecological impacts, problems which are less extensive for less densely populated countries like Bhutan and Nepal.[108] In this context, cross-border energy trade in South Asia facilitates trade between surplus-to-deficit countries, resulting in the potential for greater optimization of generation asset utilization and availability of electricity across the region with reduced adverse environmental impact.

The economic shift of developing nations in South Asia from traditional agriculture to industrial and service sectors has increased the demand for commercial energy like transportation fuels and electricity.[109] However, the natural resources required to meet the evolving patterns of increased energy demand are either limited or are largely untapped.[110] This mismatch can discourage domestic as well as foreign direct investments and impede economic growth. Cross-border trade provides these countries an opportunity to take advantage of their own unique comparative advantage to export resources while meeting the needs of their respective national markets. Furthermore, regional collaborations formed to facilitate cross-border energy trade may also allow countries to share the costs and benefits of the energy projects, ultimately reducing immediate financing burdens and reducing project risks for individual countries.[111] Larger economies in the region can provide substantial portions of the investments needed to develop regional energy infrastructure, which lessens the burden of smaller economies, eases supply constraints, and reduces energy costs.[112] Additionally, regional cooperation platforms bring countries together to mitigate climate change through improvements in energy efficiency and promotion of renewable energy within the region.[113] For example, hydropower trade between Bhutan and India reduces the need for coal power generation in India and contributes to climate change mitigation.[114]

Currently, Bhutan, Bangladesh, and Nepal conduct cross-border transactions of electricity with India.[115] For example, Nepal, which is facing power shortages despite its hydro-electric power potential, imports electricity from India, including under a commercial trade arrangement.[116] Nepal has a hydro-dominated power system that relies mainly upon run-of-river schemes for power

107. *Id.* at 11-12.

108. SULTAN HAFEEZ RAHMAN ET AL., ASIAN DEV. BANK, ENERGY TRADE IN SOUTH ASIA: OPPORTUNITIES AND CHALLENGES 6, 16-17 (2011), https://www.adb.org/sites/default/files/publication/29703/energy-trade-south-asia.pdf.

109. *Id.* at 8.

110. *Id.* at 8-9.

111. *Id.* at 4-5.

112. *See* SULTAN HAFEEZ RAHMAN ET AL., *supra* note 108, at 66-67.

113. *Id.* at 12.

114. *Id.* at 38.

115. *See* WIJAYATUNGA & P.N. FERNANDO, *supra* note 105 at 2.

116. *Id.* at 2, 11-12.

generation.[117] Hydropower generation peaks during the April–October wet season in Nepal, requiring hydropower projects to manage excess generation that arises.[118] This excess energy currently is exported during the same wet season to India, which faces acute power shortages at this time due to the difficulty of processing and transporting coal in wet conditions.[119] Conversely, during Nepal's October–March dry season, the country faces shortages of power and imports some of its supply from India.[120]

Existing cross-border electricity trade under bilateral electricity trade agreements and other prospective projects, have set the foundation for furthering cooperation and sharing of cross-border infrastructure, establishing regional power producers, and enhancing competition across the regional market. All these developments will potentially lead to the formation of a common grid between these South Asian countries, which will help optimize the utilization of coal resources in India and Pakistan, hydropower resources in Nepal and Bhutan, and gas resources in Bangladesh.[121] "Cross-border electricity trade in the South-Asian region has the potential to grow to 60,000 MW through 2045 with the likely strengthening of regional power cooperation among India, Bhutan, Bangladesh, Nepal, Pakistan, Sri Lanka, and Myanmar."[122]

B. Bilateral or Multilateral Agreements Have Made Nepal and Other South Asian Countries More Hospitable to Energy Investors.

1. Aspects of Power Trade Agreement with India

Currently, Nepal only "has interconnecting transmission lines with India."[123] Power exchange between these two countries takes place at over twenty interconnections through 11 kV, 33 kV, and 132 kV transmission lines, but these connections are not adequate to accommodate the transfer of summer excess power generating capacity from Nepal to India.[124] The total electricity flow across these cross-border transmission lines is about 488MW.[125] With these existing cross-border transmission lines, electricity trade with India has been domi-

117. SULTAN HAFEEZ RAHMAN ET AL., *supra* note 108, at 41.

118. *Id.* at 41.

119. *Id.*

120. *Id.*

121. DR. ANOOP SINGH ET AL., PROSPECTS FOR REGIONAL COOPERATION ON CROSS-BORDER ELECTRICITY TRADE IN SOUTH ASIA, INTEGRATED RSCH. ACTION FOR DEV. 12-13 (2018), https://irade.org/Background%20Paper%20revised,%20Write%20Media,%20Oct18.pdf.

122. Ankush Kumar, *Electricity Trade in South Asian Could Grow Up to 60,000 Mw Through 2045*, ETENERGYWORLD (Nov. 9, 2018), https://energy.economictimes.indiatimes.com/news/power/electricity-trade-in-south-asian-could-grow-up-to-60000-mw-through-2045/66477793.

123. PRAKASH GAUDEL, CROSS-BORDER ELECTRICITY TRADE: OPPORTUNITIES AND CHALLENGES FOR NEPAL 2 (2018), https://www.academia.edu/37278969/Cross_Border_Electricity_Trade_Opportunities_and_Challenges_for_Nepal.

124. *Id.*

125. *Id. See* HON. BARSHAMAN PUN, PRESENT SITUATION AND FUTURE ROADMAP OF ENERGY, WATER RESOURCES AND IRRIGATION SECTOR 6 (2018), https://cip.nea.org.np/wp-content/uploads/2020/09/KMS-6-white-paper-on-energy-water-resources-and-irrigation-sector.

nated mainly by increasing imports.[126] "Nepal's allowable import of electricity from India is 800 MW."[127] Nepal, in 2021, imports a total of 250 MW of electricity from India and has agreed to import an additional 100 MW.[128] Nepal has never had a surplus in energy trading with India in the past two decades.[129]

Cross-border electricity trade agreements between India and Nepal include agreements regarding the development of projects on trans-boundary rivers which flow from Nepal to India, including the 'Treaty Between the Government of Nepal and the Government of India.'[130] These agreements were primarily established to develop irrigation and control floods, but because electricity is produced as a byproduct, these agreements include provisions for cross-border electricity trade.[131]

For example, under Article 4 (ii) of the amended Koshi Agreement, Nepal is entitled to use "up to 50% of the total hydroelectric power generated by any powerhouse situated within 10-mile radius from the [Koshi Barrage]"[132] upon payment of certain tariffs fixed by mutual understanding.[133] Similarly, under the Gandak Agreement, the Government of India agreed to construct both a "powerhouse with an installed capacity of 15,000 KW-hour in Nepali territory on the Main Western Canal" and a transmission line from that powerhouse to the Bihar border[134] in order to facilitate supply of power to any point in the Bihar Grid up to and including Raxaul.[135] Under Article 2 of the Mahakali Treaty, Nepal is entitled to an annual supply of "70 million KW-hour of energy on a continuous basis, free of cost, from" Tanakpur Hydropower Plant located in India.[136] This year, India opened the energy exchange market, NEA from Nepal can sell surplus energy to the Indian market via India Energy Exchange Limited (IEX),[137]

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126. GAUDEL, *supra* note 123, at 2.

127. *India Agrees to Add 100 MW to Nepal's Electricity Import,* SOUTH ASIA SUBREGIONAL ECON. CORP. (Jan. 31, 2021), https://www.sasec.asia/index.php?page=news&nid=1228&url=nepal-adds-100mw-import.

128. *Id.*

129. *Nepal's Export of Electricity Surpasses Imports from India*, MY REPUBLICA (Aug. 25, 2021), https://myrepublica.nagariknetwork.com/news/nepal-s-export-of-electricity-surpasses-imports-from-idia/#:~:text=KATHMANDU%2C%20August%2025%3A%20Nepal's%20export,imports%20stood%20at%2023%20MW.

130. Revised Agreement between His Majesty's Government of Nepal and The Government of India on The Koshi Project, Nepal-India, Dec. 19, 1966, available at https://www.moewri.gov.np/storage/listies/May2020/revised-agreement-on-nepal-and-india-koshi-river-1966.

131. *Id.*

132. *Id.* at art. 4(ii). The Koshi Barrage, located near the Indian border with Nepal, is a water channel traversing the Koshi River used to move vehicles, bicycles and pedestrian traffic.

133. *Id.* at art. 4(iv).

134. Nepal shares a boundary with Indian states Bihar and Raxaul.

135. Agreement Between His Majesty's Government of Nepal and the Government of India on the Gandak Irrigation and Power Project, Nepal-India, art. 8(i)-(ii), Dec. 4, 1959, https://www.moewri.gov.np/storage/listies/May2020/aggrement-on-nepal-and-india-gandak-river-1959.

136. Treaty Between His Majesty's Government of Nepal and the Government of India Concerning The Integrated Development of the Mahakali Barrage Including Sarada Barrage, Tanakpur Barrage and Pancheshwar Project, Nepal-India, art. 2 (2)(b), Feb. 12, 1996, https://www.moewri.gov.np/storage/listies/May2020/treaty-between-nepal-and-india-on-mahakali-rive-1996.pdf.

137. Prithvi Man Shrestha, *Delhi Opens Door for Nepal to Sell Power in India's Energy Exchange Market*, KATMANDU POST (Nov. 2, 2021), https://kathmandupost.com/national/2021/11/02/delhi-opens-door-for-

based on the Power Trading Agreement,[138] which was signed in 2014 between Nepal and India. In addition, Indian Ministry of Power Guidelines for Import/ Export (Cross Border) of Electricity- 2018[139], which mandates the "import/ export of electricity between India and the neighboring country(ies) may be allowed through mutual agreements between Indian Entity(ies) and Entity(ies) of the neighboring country(ies) under the overall framework of agreements signed between India and the neighboring country(ies)."[140] In the result, Nepal could sell surplus energy or tradeable energy to India and by having tri-parties mutual agreement energy trade to the Bangladesh in near future.[141]

2. Memorandum of Understanding between the Government of Nepal and the Government of the People's Republic of Bangladesh on Cooperation in the Field of Power Sector

Recent bilateral agreements may accelerate energy trade and cooperation between countries in the South Asian region. In August 2018, Nepal signed a Memorandum of Understanding (MoU) between The Government of Nepal and The Government of The People's Republic of Bangladesh on Cooperation in the Field of Power Sector, 2018. This agreement involves the investment, development, and trade of hydroelectricity between the two countries, strengthening the bilateral Bangladesh/Nepal relationship.[142] Under the MoU, "Bangladesh will import up to 9,000 MW of surplus hydropower from Nepal by 2040," consistent with Nepal's plan to reach certain economic goals by 2041.[143] Reaching those goals requires (1) "sustained production of energy to feed the ever-growing energy demand" from the . . . industrial sector and (2) the replacement of "nonrenewable natural gas [that comprises] 75 percent of [Bangladesh's] total fuel consumption."[144] The agreement can play a positive role in making Nepal more attractive to energy investments from Bangladesh.

The MoU is the framework for electricity "trade between Nepal and Bangladesh at mutually agreed-upon prices," and both countries have agreed to ex-

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nepal-to-sell-electricity-in-india-s-energy-exchange-market?fbclid=IwAR32PQ_4-HYZLd73O6PRwspD R3qgX1-uQ2c9Y2f1h98hAZfP5Bvsubfy_kk.

138. Agreement Between the Government of Nepal and the Government of the Republic of India on Electric Power Trade, Cross-Border Transmission Interconnection and Grid Connectivity, Nepal-India, Oct. 21, 2014, https://www.moewri.gov.np/storage/listies/May2020/pta-english-21-oct-2014.

139. Ministry of Power, Guidelines for Import/ Export (Cross Border) of Electricity-2018 (Issued Dec. 5, 2016).

140. *Id.* at § 3.1.

141. Memorandum of Understanding (MoU) between the Government of Nepal and the Government of the People's Republic of Bangladesh on Cooperation in the Field of Power, Nepal-Bangl., Aug. 10, 2018, https://www.moewri.gov.np/storage/listies/May2020/mou-between-nepal-and-bangladesh[hereinafter Nepal-Bengl. MOU].

142. *Id.*

143. Muhammad Hasanujzaman & Umesh Raj Rimal, *Bangladesh-Nepal Energy Cooperation; The Horizon of New Possibilities*, HIMALAYAN TIMES, (Sep. 7, 2020), https://thehimalayantimes.com/business/bangladesh-nepal-energy-cooperation-the-horizon-of-new-possibilities.

144. *Id.*

change power "when it is possible and feasible."[145] The parties have expressed their commitment to enhance cooperation in the field of electric power, including through investment and development of power generation projects for mutual benefit.[146] The agreement requires the parties to encourage and facilitate joint cooperation in developing power generation projects, providing consultancy services and training programs, encouraging cooperation between the public and private sector players of each country, and supporting joint venture investments in the energy sector.[147]

The MoU has faced barriers to its full implementation, however, India is located between Nepal and Bangladesh and electricity from Nepal can only be exported to Bangladesh using Indian transmission lines.[148] Delays in concluding a trilateral agreement between Nepal, India, and Bangladesh, have prevented the finalization of an agreement between Nepal and Bangladesh for electricity trade.

3. South Asian Association for Regional Cooperation (SAARC) Framework Agreement on Energy Cooperation (Electricity)

Multilateral agreements also have the potential to improve the flow of electricity traded across the South Asian nations. The SAARC Framework Agreement for Energy Cooperation (Electricity) (SAARC Framework Agreement) was signed by all Member States of SAARC, including Nepal, on November 27, 2014, during the 18th SAARC Summit held in Nepal.[149] The preamble to the agreement affirms that the Member State signatories recognize "the importance of electricity in promoting economic growth and improving the quality of life," and understand how the "common benefits of cross-border electricity exchange and trade among the SAARC Member States" enhance grid security and address problems arising from the "diversity in peak demand and seasonal variations" among the Member States.[150] The Parliament of Nepal ratified the SAARC Framework Agreement on August 30, 2016.[151]

The Agreement emphasizes cooperation in the electricity sector, in part, because all Member States lack sufficient hydrocarbon fuels to meet their domestic needs.[152] "All SAARC Member States are dependent on petroleum imports,

145. Nepal-Bangl. MOU, *supra* note 141, at art. 1. *See* Dr. Dhrubajyoti Bhattacharjee, *Growing Synergy in Energy Cooperation Between Bangladesh and Nepal*, INDIAN COUNCIL OF WORLD AFFAIRS (Sep. 23, 2021), https://www.icwa.in/show_content.php?lang=1&level=3&ls_id=6379&lid=4392.

146. Nepal-Bangl. MOU, *supra* note 141, at art. 2.

147. *Id.*

148. Prahlad Rijal, *Nepal-India-Bangladesh Talks on Power Trade Long Overdue*, KATHMANDU POST (Dec. 9, 2019), https://kathmandupost.com/money/2019/12/09/nepal-india-bangladesh-talks-on-power-trade-long-overdue.

149. SAARC Framework Agreement for Energy Cooperation (Electricity), Afg.-Bangl.-Bhutan-India-Maldives-Nepal-Pak-Sri Lanka, Nov. 27, 2014, https://www.moewri.gov.np/storage/listies/May2020/saarc-framework-agreement [hereinafter SAARC Framework Agreement].

150. *Id.*

151. Bibek Subedi, *Saarc Energy Cooperation Pact Gets Parliament Nod*, KATMANDU POST (Aug. 30, 2016), https://kathmandupost.com/money/2016/08/30/saarc-energy-cooperation-pact-gets-parliament-nod.

152. ASIAN DEV. BANK, HARMONIZING ELECTRICITY LAWS IN SOUTH ASIA; RECOMMENDATIONS TO IMPLEMENT THE SOUTH ASIAN ASSOCIATION FOR REGIONAL COOPERATION FRAMEWORK AGREEMENT ON

[and] some even import up to 100%" of their petroleum needs.[153] Natural gas cannot be traded between the Member States because, with the exception of Bangladesh, countries in the region that use natural gas, including India and Pakistan, are unable to meet their gas demand using solely domestic sources.[154] India, despite having significant coal-based generating capacity, also imports coal for power generation and other uses to meet high domestic demand.[155] Given the limited possibilities for regional trade in petroleum, natural gas, and other hydrocarbon fuels, electricity generated from large renewable energy sources in South Asia, including hydropower, wind, solar, biomass, and geothermal resources, can be harnessed for both domestic use and to meet energy shortfalls through regional power trade.

The Agreement acts as the foundation for electricity trade in South Asia and has opened up opportunities for energy investment in the region. It sets the guiding principles for enabling cross-border trade of electricity on a voluntary basis, between "Buying and Selling Entities"[156] of the SAARC Member States, "subject to the laws, rules, and regulations of the respective Member States, and based on bilateral or [multilateral agreements] between the concerned states."[157]

Consistent with its objective to facilitate and promote cross-border energy trade, the Agreement sets forth roles, powers, and responsibilities of Member States, Buying and Selling Entities, National Grid Operators, Transmission Planning Agencies of each member state's government, Transmission Service Providers, and the SAARC Arbitration Council.[158] For example, the Member States have committed to enable Buying and Selling Entities to engage in cross-border electricity trade, to develop procedures for that trade, to enable nondiscriminatory access to transmission grids, to promote competition, to coordinate on reliability and security of Member States' grids, and to coordinate the procedures and practices of Member States' grid operators, including dispatch procedures.[159] Moreover, Member States have considerable opportunities for negotiation and cooperation, including working toward exempting import and export duties and fees, enabling the Buying and Selling Entities to negotiate their terms of payment, assisting the transmission planning agencies of the Member States in

ENERGY TRADE (ELECTRICITY) 4 (2017), https://www.adb.org/sites/default/files/publication/375496/harmonizing-electricity-laws-sasia [hereinafter HARMONIZING ELECTRICITY LAWS WHITE PAPER].

153. *Id.*

154. *Id.*

155. *Id.* at 19-20.

156. SAARC Framework Agreement, *supra* note 149, at art. 3. Article 1 of the SAARC Framework Agreement for Energy Cooperation (Electricity) defines "Buying and Selling Entities [as] any authorized public or private power producer, power utility, trading company, transmission utility, distribution company, or any other institution established and registered under the laws of any one of the Member States having permission of buying and selling of electricity within and outside the country in which it is registered." *Id.* at art. 1.

157. *Id.* at art. 2.

158. *Id.* at art. 7, 9, 11, 16.

159. *Id.* at art. 6, 10-12.

building and maintaining cross-border interconnections, and enabling knowledge sharing and information exchanges between Member States.[160]

One of the most important features of the Framework Agreement is that its articles are generally subject to "laws and regulations of the concerned Member States."[161] But this is also one of the Agreement's weaknesses. As the Asian Development Bank (ADB) notes in its 2017 study:

> Few of the countries in the region—Bangladesh, Bhutan, and Nepal—made requisite provisions in their laws to recognize and regulate the cross-border electricity trade within. As a result, the prevailing electricity laws, regulations, and policies of other SAARC member states (SMSs) are designed to govern sector operations within the country only.[162]

Therefore, ADB notes, Member states each need both a strong legal and regulatory framework and to "[h]armonize their electricity laws, regulations, and policies with those of the other countries in the region" to maximize interregional trade benefits. ADB's report has identified a number of ways in which this can be accomplished.[163] Therefore, a strong legal and regulatory framework in each of the Member States by harmonizing regulatory environment are vital for proper implementation of the provisions of the Framework Agreement.

4. Remaining Challenges Require That the Regional Regulatory Framework Consider the Difficulty of Implementing Reforms in Developing Countries Like Nepal

Although bilateral and multilateral agreements have increased opportunities for cross-border energy trade, significant challenges remain. Developing countries like Nepal might place a higher priority near term on satisfying domestic consumption rather than on exporting power. Moreover, developing countries might have limited and inefficient energy infrastructure which may reduce the effectiveness of these regional agreements, or they may have limited negotiating power against more developed nations.

Despite having abundant hydropower potential, Nepal has been struggling to meet its own energy demands.[164] Hydropower development policy in Nepal assumes that electricity may be exported to foreign countries. But satisfying internal consumption and increasing per capita electricity consumption domestically may be a higher priority. Moreover, Nepal is losing potential revenue from electricity export sales because of its inadequate and unreliable power system infrastructure.[165] Hydropower generation remains inadequate due to limited government resources, lack of foreign direct investment, and inadequate domestic

160. SAARC Framework Agreement, *supra* note 149, at art. 3-4, 8, 14.

161. *Id.* at art. 13.

162. HARMONIZING ELECTRICITY LAWS WHITE PAPER, *supra* note 152, at 47.

163. *Id*.

164. *Power-Less to Powerful,* WORLD BANK, (Nov. 25, 2019), https://www.worldbank.org/en/news/feature/2019/11/25/power-less-to-powerful.

165. ASIAN DEV. BANK, COUNTRY PARTNERSHIP STRATEGY, NEPAL, 2013-2017, at 2 (2013), https://www.adb.org/sites/default/files/institutional-document/34001/files/cps-nep-2013-2017.pdf.

private financing. In addition, Nepal's reliance on underperforming assets—with poor operation and maintenance of those assets—have led to high technical losses and inefficient power systems.[166]

Nepal and other developing countries in South Asia face four general areas in which barriers inhibit robust energy infrastructure. These involve impediments in the policy, technical, institutional, and financial areas.[167] For example, the lack of adequate infrastructure to deliver electricity from generation plants to load centers has been a significant challenge.[168] This lack of infrastructure may be attributed in part to weak institutional capacity, the weak financial position of the NEA, and limited human resources and management experience within the NEA.[169] Other challenges include limited energy sector planning, policies, and regulations, as well as a lack of coordination on strategies by institutions involved in the energy sector.[170]

Nepal's energy development is also hampered in its ability to negotiate effectively in cross-border electricity trade with India, a more developed nation. As an example of Nepal's weaker negotiating power vis-à-vis India, India's Guidelines on Cross-Border Trade of Electricity in 2016 contained clauses that appeared contradictory with the SAARC Framework Agreement and the Indo-Nepal Power Trade Agreement by "provid[ing] preferential *one-time* approval for all entities with 51% or more Indian ownership wishing to export electricity from Nepal to India" while stating that all other entities need to be considered on a case-by-case basis.[171] While such unilateral actions may be the preferred *modus operandi* of India,[172] they are inconsistent with the spirit of the operative bilateral and multilateral cooperative agreements on energy trade.

Hydropower projects are increasingly facing environmental concerns that can create additional development problems. For example, water diversion for hydropower generation, particularly in run-of-river projects, can make the downstream stretch of the river completely dry, which has adverse impacts on the aquatic and terrestrial ecosystem as well as livelihood of the people dependent on those systems.[173] Similarly, construction of dams in larger hydropower projects necessitates complex and expensive structures that can give rise to multiple environmental problems.[174] Other negative impacts, including involuntary dis-

166. *Id.*

167. P.R. Khadka & P. Adhikari, Regional Power Trading; In: Proceedings of 6th International Conference on Development of Hydropower- A Major Source of Renewable Energy (2005).

168. ASIAN DEV. BANK, *supra* note 102, at 2.

169. *Id.* at 10.

170. *Id.* at 9.

171. Santa Bahador Pun, *Reflections on SAARC Framework Agreement for Energy Cooperation (Electricity) Vis-à-vis India's "Guidelines on Cross-border Trade of Electricity"* 22 HYDRO NEPAL: J. OF WATER, ENERGY AND ENV'T 1 (2018), https://www.nepjol.info/index.php/HN/article/view/18989.

172. *Id.*

173. Ramesh Prasad Bhatt, Hydropower Development in Nepal - Climate Change, Impacts and Implications, *in* RENEWABLE HYDROPOWER TECHNOLOGIES (Basel I. Ismail ed., 2017), https://www.intechopen.com/chapters/53350.

174. *Id.*

placement and loss of fertile land, affect the microclimate of the region and the people living within it. Despite the potential for cross-border trade in hydropower, national plans for hydropower development and export have failed to include sufficient socio-environmental considerations.[175]

IV. CONCLUSIONS AND LESSONS LEARNED

Although foreign energy investment in Nepal has been limited by regulatory challenges, including the tensions between federal, provincial, and local legal regimes, there are concrete solutions for regulatory reform and additional opportunities to encourage foreign direct investment in generation and energy infrastructure. These solutions include legal regulatory and institutional reforms, such as establishment of an independent Electricity Regulatory Commission for coherent technical management, tariff determination, regulation of power purchase, ensuring competition and protection of consumers, enhancement of capacity of licenses and corporate governance, inspection and monitoring of compliance, dispute resolution, enactment of law to promote cooperation, co-existence and coordination between different levels of government and an unbundled structure of the Nepal Electricity Authority to promote competition and commercialization.

Recent bilateral and multilateral agreements in South Asia have also contributed to increased interest in foreign direct investment and cross-border energy trade. Despite their potential, at this time these regional frameworks do not yet successfully address conflicting national laws, uneven negotiation power between countries, or the difficulty of implementing reforms in developing countries like Nepal. Assuming those challenges can be overcome, these agreements can be the bases for improved energy systems across the South Asian region that will improves the lives of those living in Nepal and its neighboring countries.

175. GAUDEL, *supra* note 123, at 8.

PAST THE TIPPING POINT: HOW REGULATORS AND UTILITIES ARE AND WILL BE LOOKING AT WAYS TO MITIGATE THE INEVITABLE IMPACTS OF CLIMATE CHANGE

The following is a transcript of the Energy Law Journal/Energy Bar Association January 12, 2022 online symposium: "Past The Tipping Point: Looking at Ways to Mitigate the Inevitable Impacts of Climate Change." On August 7, 2021, the UN's Intergovernmental Panel on Climate Change released a report that produced an unnerving two-fold conclusion: The world has already passed the tipping point – no matter what we do we will face unavoidable and serious climate change impacts that we – humans – have already caused. Only if we act now, the report adds, will we have the hope to avoid a complete climate catastrophe. The panel of experts participating in the symposium examined what policy makers and utilities are already doing and can do to mitigate the various impacts of climate change on the reliability, resiliency and affordability of utility services, and discussed the analytic tools at utilities' disposal, the legal and practical limits on regulatory changes and the strategies utilities and policymakers may utilize as they decarbonize their power systems.

Moderator: Harvey Reiter
Panelists: Roshi Nateghi[1],
Judsen Bruzgul[2], Heather Payne[3], Michael Craig[4]

PANEL DISCUSSION

MS. BARTELL: Hello everyone. My name is Sylvia Bartell and I am the president of the Foundation of the Energy Law Journal. I'm pleased to welcome our distinguished panelists, our moderator, and all attendees to today's symposium titled Past the Tipping Point, Looking at Ways to Mitigate the Inevitable Impacts of Climate Change.

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1. Michael Craig: Assistant Professor of Energy Systems at University of Michigan- School for Environment and Sustainability, PhD, Engineering and Public Policy, Carnegie Mellon University (2017) MS, Technology and Policy Program, Massachusetts Institute of Technology (2014) BA, Environmental Studies (Ecology), Washington University in St. Louis (2010).

2. Judsen Bruzgul: Senior Director, Climate Adaptation and Resilience + ICF Climate Center Senior Fellow, Ph.D., Stanford University, B.A., Middlebury College

3. Heather Payne: Associate Professor of Law, Seton Hall University School of Law, J.D.; University of North Carolina School of Law; BChE, Georgia Institute of Technology

4. Roshanak Nateghi: Associate Professor of Industrial Engineering, Purdue University School of Industrial Engineering, PhD, Geography and Environmental Engineering, Johns Hopkins University, 2012, MSE, Geography and Environmental Engineering, Johns Hopkins University, 2008, MEng, Mechanical Engineering, Imperial College London, 2006

This event marks the first time the Energy Law Journal has sponsored its own symposium.

In that regard, I would like to thank the Energy Law Journal's editor-in-chief, Harvey Reiter, who is also today's moderator, the executive editor, Caileen Gamache, our numerous article editors, the student editors of the Energy Law Journal at the University of Tulsa, College of Law, and finally, our panelists.

Throughout this event, please take a moment to read through the attendee list. You all make up a cross-cutting group of individuals, each with unique abilities and perspectives to contribute to the Herculean endeavor of fighting and mitigating the effects of climate change. Let this symposium be just one aspect of our engagement with this topic. We hope today's event inspires further discussion and, importantly, action.

As always, the Energy Law Journal welcomes submissions of original articles on this and any other topic of interest to the legal profession and energy professionals. Finally, this recording will be made available to attendees and the Energy Bar Association members.

With that, I will turn it over to our moderator, Harvey Reiter.

MR. REITER: Thanks so much, Sylvia, and thanks to all the attendees here and to our distinguished panelists. So, let me briefly introduce our panelists today. Hopefully, you'll be hearing a lot more from them in the coming hour and a half plus.

Roshi Nateghi is a professor of industrial engineering at Purdue University and director of its Laboratory for Advancing Sustainable Infrastructure. She's currently on leave from Purdue to work with the Department of Energy's Office of Energy Efficiency and Renewable Energy.

Judsen Bruzgul is the Senior Director of Climate Resilience at ICF and Judsen has advised clients on challenges of climate risk for 20 years.

Heather Payne is a former chemical engineer, but now a distinguished professor of law at Seton Hall, teaching and writing on the intersection of energy and environmental law.

And finally, Michael Craig is a Professor of Energy Systems at the University of Michigan School for Energy and Sustainability.

I want to welcome all of them here and I also want to talk a little bit about why we're here today. Probably one of the precipitating events was the August U.N. Panel on Climate Change Report announcing two unnerving conclusions: that we're already passed the tipping point on climate change and we can only keep things from getting worse.

The U.N. Secretary General called the report Code Red for humanity. So, when we talk about climate change being past the tipping point, we're talking about certain irreversible changes no matter what we do. What are some of these things? We'll see more storms, more hurricanes, more heatwaves, more wildfires, flooding, and tornadoes, and their intensity will increase too. While no one weather event constitutes a trend, it's hard to ignore the numerous record-setting events we just saw over the last seven months. If you could just put up a chart, this will be a little bit of a reminder about what we've seen:

Extreme Weather Events June-December 2021

June 20, 2021- Temperature in Verkhoyansk, Siberia reaches 100° F. – a new temperature record for the Arctic.
June 29, 2021 -- Temperature in Lytton, British Columbia – a small town located eighty miles north of Vancouver -- reached 121° F, hotter than the highest temperature ever recorded in Las Vegas
August 11, 2021—190 wildfires spread across Siberia - covering an area larger than the fires in Greece, Turkey, Italy, the United States and Canada combined
August 11, 2021 – Temperatures in Sicily reached 120° F.-- the hottest day ever recorded in Europe
August 14, 2021- rain fell for the first time in recorded history at the highest point on the Greenland ice sheet
August 21, 2021 – 17 inches of rain fell in Waverly, Tennessee, followed by massive flash flooding
August 26, 2021 -- Hurricane (later Tropical Storm) Ida makes landfall, ultimately killing a hundred persons in the U.S. and causing massive destruction from Venezuela to Nova Scotia, into October.
September 7, 2021 – Death Valley reaches 122° F. – "the hottest temperature ever recorded this late in the calendar year anywhere in the world."
December 10, 2021 – a deadly string of tornadoes hits Kentucky and seven other states, killing scores and virtually wiping out entire towns.
December 14, 2021 - Artic Global Report Card declares that Artic temperatures are rising twice as fast as the global average, scientists at American Geophysical Union conference predict that Antarctica's Thwaites Glacier could collapse within 3-5 years

Think about last June. On June 20th, the temperature in Siberia reached 100 degrees Fahrenheit. That was the highest temperature ever recorded north of the Arctic Circle. Later that month, the temperature in Lytton, British Columbia, a small town 80 miles northeast of Vancouver, reached a temperature of 121 degrees. That's hotter than the highest temperature ever recorded in balmy Las Vegas.

In August, early August, 190 wildfires spread across Siberia and covered an area larger than the wildfires that happened the same year in Greece, Turkey, Italy, the United States, and Canada combined. Later that same day in August, the temperatures in Sicily reached 120 degrees Fahrenheit. That's the highest temperature ever recorded in all of Europe.

Later that month, rain fell -- rain – for the first time at the highest point of the Greenland Ice Sheet. And again, in August, 17 inches fell in one day in Waverly, Tennessee, followed by massive flash flooding. Later that month, again, in August, Hurricane Ida struck and that was a hurricane that caused damage all the way from Venezuela in August to early October damage caused in Nova Scotia. In the meantime, as a hurricane, it killed 100 people -- some of them flooded in their basements – throughout the United States' east coast.

In September, we saw Death Valley reach a temperature of 122 degrees Fahrenheit, again, another record. This was the highest temperature ever recorded anywhere on Earth that late in the year. And December was another record month. We saw again a string of tornadoes hit Kentucky and in seven other states, wiping out entire towns.

And on the 14th of December, the Arctic Global Report declared that Artic temperatures are rising twice as fast as the global average. The scientists at the American Geophysical Union Conference predict that Antarctica's Thwaites Glacier could collapse in three to five years.

And after I'd prepared this chart, we had a couple of other events. First-time events like the first ever December tornado in Minnesota and the wildfires, December wildfires, in Colorado. And just yesterday, we had a report in the Guardian, the U.S. edition of the Guardian newspaper, that the highest ever reported ocean temperatures had occurred in 2021, breaking the record set in 2020, which in turn, broke the record set in 2019. So, what can we take from all of this and what is its relation to what we'll be talking about today?

Now, I imagine that none of the conclusions of the U.N. Report came as a surprise to any of our panelists. They've been looking at the impacts and the potential impacts of climate change on utility systems and how we respond for a number of years.

Let me talk a little bit about how we're going to structure our discussion today. First, I'm going to go around the virtual room and ask our panelists to talk about their current work and then we're going to divide our session into four segments. The first segment will focus on the types of climate risks we face and how they affect utility systems and the consumers who rely on them. Then, we'll talk about some of the analytical tools available at regulators and utilities' disposal to address these issues.

The third segment will focus on how different regulators and utilities around the United States, and to some extent around the world, are responding to climate risks. And the last segment session, and certainly not the least important, is the question of affordability to address resiliency and mitigation measures.

So, let me start first by going around our virtual room and we'll start with Roshi, if you could talk a little bit about your work.

MS. NATEGHI: Sure. So, in my research we assess the risk and resilience of energy systems under extreme events and climate change. For example, we've looked at the short, medium, and long-term impacts of hurricanes and extreme heat events on power distribution systems and I'm happy to talk about some of the highlights of the work later, but more recently, we are thinking about compound climate risks.

What I mean by compound climate risk is for example, droughts and heatwaves happening concurrently or when a heatwave follows shortly after a hurricane. And there's clear evidence that their likelihood and intensity are increasing under climate change and yet, there is very little understanding of how to model their amplified impacts on infrastructure and energy systems and communities, and that's the area that we are hoping to contribute to now.

MR. REITER: Yes, Judsen, if we could just turn to you now and you could talk a little, briefly, about some of the work that you're doing.

MR. BRUZGUL: Sure. Thank you, Harvey, and thanks to the Energy Bar Association and the Energy Law Journal for hosting this. I think it's a very timely panel and I'm delighted to be part of it.

I'm with ICF. We're a consulting firm. For those of you who aren't familiar, we're headquartered in Northern Virginia with about 7500 employees across the country and overseas. I work as a senior director for climate adaption and resilience and lead our work on climate resilience in the energy sector.

I'm also a senior fellow at our ICF Climate Center, which is a new platform that pulls together original data and insights on climate trends and brings together our more than 2,000 climate, energy and environmental experts across ICF. So, this is an area and a domain that we've been working in for a long time and I've spent my entire career working on climate impacts, understanding climate impacts to natural and human systems.

I've been with ICF for the last eight years focused on this work. Specifically, I'm working directly and our teams are working directly with utilities, as well as with the Department of Energy and other state and federal agencies to help understand risks from climate change. That includes translating the science of climate change into actionable and decision-oriented information, really making it relevant to the work that they do and their ability to manage risks.

In terms of understanding and assessing risks, we provide a lot of support to understand vulnerabilities across their systems, as well as their operations and planning and workforce and other aspects of their business and then to build resilience plans to mitigate those risks, think about opportunities to advance their overall resilience across their organization and ultimately to better serve their customers.

So, that's the work we've been engaged in and continue to be. I'll stop there and look forward to the rest of the discussion.

MR. REITER: Thanks, Judsen. If we could turn now to Heather.

MS. PAYNE: Thanks, Harvey. So, I am from the Seton Hall University School of Law, as Harvey mentioned, I focus on energy and environmental law. And the last couple of years my work has really been from the basic assumption that climate change is happening and that we need to electrify everything to address that. And so, I focus on regulated utilities and the legal and policy changes that are necessary to make that happen.

And so, I found myself very frequently basically telling everybody that they aren't doing enough and they aren't doing it fast enough. And lot of that, I think, comes from the fact that we have policy layers that we are not aligning. So, for example, picking on my home state of New Jersey, we have fairly decent climate goals, especially if we take executive orders into account, but at the same time we're doing things that are anathema to that still.

So, for example, actually providing efficiency subsidies for natural gas appliances as opposed to try to move toward electrical. And while law doesn't necessarily tend to be, especially among these esteemed panelists, the most practical of applications, I do try to focus my work in a practical way. So, for example, one of my articles, Natural Gas Paradox, tried to give legislators regulators, and utilities menus of options when we were thinking about how to shut down the natural gas distribution system as we electrify, especially, in terms of things like stranded assets, how we were going to deal with the financial implications of that.

I also recognize that some of our fundamental common law doctrines are going to need to change. The duty to serve, for example, is going to have to be modified as we deal with climate change and our increasingly extreme weather events. Most importantly, I think, and thanks to the Energy Law Journal for having this discussion, is we really need to be planning for and talking about the significant action that has to happen to get to that decarbonized future now.

And obviously, as we go through the conversation today, all opinions are my own and not necessarily those of my employer.

MR. REITER: Thanks Heather. I remember when I was working for the Federal Energy Regulatory Commission and I gave a talk, and one of the things I said was that my opinions are solely my own and not necessarily those of the Commission or the Commissioners, no matter how persuasive and logical I may be.

So, let me turn last to Michael Craig, Michael, to talk a little bit about your work.

MR. CRAIG: Thanks Harvey, and to Sylvia and the rest of the team for organizing this event. I'm looking forward to talking with the rest of the panelists and to thank all of you for attending.

My name is Michael Craig. I'm an assistant professor at the University of Michigan where I study energy systems in the School for Environment and Sustainability and I run the ASSET Lab. So, our research really is in two tracks on mitigation of climate change and adaptation to climate change. We're going to focus mostly on adaptation here. And my research is mostly in the power system, so we build large-scale models of regional power systems. You can think of multi-state regions where you can interconnect scales, like the eastern United States and the western United States.

And then we perturb those systems with future metrology under climate change instead of historic metrology to ask how bad could things get in the power system and what do we need to do to adapt to climate change and we do this work, partly, on long-term funded -- you know your typical academic projects like from the Department of Energy or the National Science Foundation, but we also do a lot of short-term projects on behalf of utilities or stakeholders because myself, and the rest of my students included, really do a lot of applied research where we're trying to answer practical, real-world problems.

So, I'll work in more of my research as we go through, but that's a high-level overview for now.

MR. REITER: We should have plenty of time to talk about some of that.

So, I mentioned before that we're going to break our program down into four different segments. So, we're going to start first with what climate change impacts are we talking about and at the end of each segment, just to the audience, I wanted to mention if you have questions, please put them in the chat box and we'll try to get to those at the end of each segment. And then, we'll also have an opportunity for questions and answers toward the end of the program and we'll be able to open up the microphones then so you'll have a chance to ask some follow-up questions.

So, let me start with our first topic. What are some of the climate change-related events about which regulators and utility planners are now focusing on? And I know, Roshi, you mentioned the complicating factor of multiple climate events or weather events that have their own special impacts. So, I'll open up to the panel, whoever wants to start first.

MS. NATEGHI: I'm happy to chime in first and then I'm actually very curious to learn from the panelists, as well.

So, my impression is based on reading the literature and my interactions with utilities that on paper we are concerned about all hazards, ranging from cyber threats to malicious acts to climate hazards. Think about tornadoes, wildfires, hurricanes, and droughts. When you look at the bipartisan infrastructure bill, now there is the $27 billion budget to operate and modernize electrical grid to make it resilient to climate events and cyberattacks.

But if you look at the historical data from the Federal Emergency Management Agencies. I'm just going to refer to it as FEMA, easier to refer to the acronym. If you look at FEMA's disaster declarations, you'll see that the federal relief policies have been so responsive to rapid onset events like storms and hurricanes as opposed to slow-onset ones like heatwaves and droughts and sea level rise and that's not necessarily in line with the infrastructural and societal impacts.

For example, droughts and heatwaves are amongst the most costly and lethal events in the U.S. Just one example is the Chicago heatwave back in 1995 where 50,000 customers lost power, over 700 people died, and yet, when you go back to the disaster relief database, you'll see very disproportionately less amount of investment and responses.

And based on my group's sort of shallow survey of some other countries -- some government documents from European countries, my sense is that this is not necessarily unique to the U.S. Somehow rapid onset hazards appear to catch most of our attention and just my experience has been that there's not uniform attention spent to various types of hazards. And yes, I'm curious to hear about what the experience of other panelists have been in this area.

MR. BRUZGUL: Okay, Roshi, I think that's a really interesting perspective and I'm glad you brought it up and I'm looking forward to learning more about your research on the compounding events. I think that's a really important dimension here.

MS. NATEGHI: I would say we see broadly that folks are interested in the hazards that they're experiencing already and how those may be exacerbated. That tends to be the starting point. I think for hazards that maybe are emergent for them, either sea level rise, for example, and flooding maybe along the coast that they haven't experienced or are just beginning to experience at, let's say, a king tide event, is newer ground for folks to understand what that means for their operations and their planning, but we do see a lot of interest, of course, in sea level rise and flooding.

I think, in general, there's a recognition, just as you say, of gradual change, as well as the low probability, high-impact events however those manifests, either fast or slow. I think a low probability extended drought can have a high impact and I would put it into that category. And I think it's those things that push the conversation beyond the traditional reliability discussion and that's an important element to our work. Utilities and the power sector has dealt with storms all along and there are a lot of good approaches to managing risks from storms and other kinds of climate-driven events.

I think what we see as different is the frequency and intensity, the compounding nature. As you point out, things like consecutive winter storms, such as the Reilly-Quinn back-to-back storms in the Northeast that caused massive, long duration outages that significantly impacted customers just a couple of years ago. So, I think those are really important and the notion that these events can be longer duration, more widespread, and really need a different or at least complementary approach to reliability planning and investment I think is really significant and ties with the kinds of hazards that we see already and anticipate based on the science.

MS. PAYNE: And to pick up, Roshi, on what you said about FEMA and the longer-term hazards not being addressed, I think the Village of Kivalina really is the poster child for that, right? We have an Alaskan native village that has been pounded and is really seeing the impacts of climate change, needs money to go ahead and relocate and yet, has been denied that multiple times by FEMA because they don't view, essentially, the impacts from climate change as within their discretion.

To Judsen's point, I think that we, especially for legal reasons, are starting to see utilities take action based on climate change that they haven't before that are having a significant impact on customers, right? All of the public safety power shutoffs that we've seen in California over the last couple of years to address wildfire risk, which is primarily there because of an historic five-year drought and the fact that we had, perhaps, other reliability issues that were not addressed by the utilities as they should've been are having a massive impact on people's ability to be resilient through these different issues.

And I think that the pandemic really puts both of these different facets of it into an entirely different perspective that I don't think that we would've had before for something like public safety power shutoffs or addressing things like Hurricane Ida where traditionally what we would have done was evacuate people to things like convention centers where we would've had backups where we could have provided services now we have the potential that those are super spreader events and so the pandemic just adds another layer of an impact where we're not able to see traditional reliability and resiliency really act in the same way.

MR. CRAIG: So, I love panels where I learn on the panel, which has been great. So, I just want to add a perspective on why we care about these events. And I agree with all the other panelists in terms of the types of events and we're doing a review right now of different utilities and how they're planning for it and we see heat come up all the time, extreme heat. California of Summer 2020 had rolling blackout there. They pointed to climate change contributing to this, what they call a heat storm, which was not unique because of how bad it was, but was also bad in terms of the length of it and the special scope of it, so it's new in that way.

But they talk about extreme heat, wildfires, drought, sea overrise, but we can think about different parts of the power system and then think about where the vulnerabilities are there to understand why these events are of concern. And the major impact that we see from climate change or one of the most clear ones that are robust across studies is increasing electricity demand. As things get warmer, people run their air conditioning more and so you have increasing demand. And if you're not planning for that in your planning procedure, then you are at the risk of outages. At the same time that that is being driven by high temperatures, you also have risk at your thermal powerplants. You might have droughts contributing to low hydropower output. You might have impacts on your transmission system in terms of acute impacts like we see with a lot of safety power shutoffs or just that you have lower carrying capacity.

And so, there are these different events and they impact the power system in different ways and I think one of the challenges that we're a little behind on at this point is to think about across those different parts of the power system. How are they all going to interact or compound one another and to drive these sorts of events that we dramatically want to avoid, like outages or like turning people's power off because they're in wildfire-prone areas.

MR. REITER: So, I had a question. You've talked about how these events are not individually unique and we've had storms before. We've had droughts. We've had wildfires and some of them have even intersected in time, so those aren't themselves unique. How do you look at these events where their intensity and frequency increases and how do you approach solutions to those issues as opposed to just saying, okay, I know that we're going to have an occasional wildfire? We can harden our systems. We can underground them or something like that.

MR. BRUZGUL: Michael, did you want to respond.

MR. CRAIG: No, I'll go after you. Go ahead.

MR. BRUZGUL: Okay. Well, I'll just make a comment or two on that question. I would say two things. One is a sense of there's a threshold that exists to how we want to respond in the frequency or intensity, and I think Heather made a great point about, so traditionally, we would gather people and send them to the Super Dome or other places or evacuate people. If you're doing that every other week, it also starts to be something that you want to rethink as a strategy and so I think as we think about the frequency of these outages that's important.

The other element, you mentioned the pandemic, the thing that comes to my mind there is not only those gathering issues, but more people having a different relationship with their power, depending on it from home, for work, for livelihoods in a different way. We're much more dependent on it for connectivity, increasing for transportation and other services. And so, as that dynamic changes, I think the acceptance of outages is also changing and I guess that gets to my second point which is around the view of risk and the risk tolerance. And I think one of the most important conversations that we see is both lacking, in general, but is necessary is understanding the risk tolerance. What is acceptable in terms of power system performance, in terms of the level of risks that you can maintain or manage as you're delivering power for the utility because ultimately you've got to make tradeoffs about the level of investment you want to make and the resilience that will provide based on how risk tolerant or adverse you are.

I'll just give one quick example. You think of the FEMA one in a hundred-year flood plain and we tend to -- or the 1 percent annual chance flood plain. That's something we think of often. We probably don't want to build there. Everyone has the sense that it's a riskier area. We don't have that same shared view of other risks. Whether that one is right, we can debate about, but we don't have that same view on a heatwave, for example, or other kinds of challenges and those, I think, are really important to this broader conversation about what are we going to do about it and why is it different.

MR. CRAIG: Yes. And I might take the answer in a slightly different direction, which is if we think about how we have traditionally planned power systems -- and most of my research is on large scale power systems. We take a large planning model and we give it metrological data to understand what demand and supply will look like and this has been becoming increasingly important as you put more wind and solar into the system, but let's set that aside.

So, where did we get metrological data before? Well, we can go to the historic record. Utilities have long periods of reliable operations. They have these reanalysis datasets that have satellite-derived data going back 40 years and so you can go 40 years full historic record. And if you wanted to, understand how your system would withstand 40 years of historic meteorology.

Now, we're faced with a situation where we have nonstationary, meaning that prior 40 years is not representative of what we'll see in the future and so the utility picks up its head and says, okay, so where do I get my meteorology data now? And the unsatisfactory answer is you get it from climate models, but the climate models were not built to give that data to utilities. They don't capture these extreme events. Well, they're not at the resolution that they want them at and so how are things different?

The process needs to change somewhat, but the process needs to change because the data that has been driving our decisions thus far is not as useful anymore and there are limitations in the new data they want to use and so you can't just take a pipeline where you used to shove data in and take this new data and shove in instead. That has a limit to it because the data itself has issues with is and so that's where we need to think about where the processes at the planner level needs to change to account for the fact that the data is not quite what you expected it to be.

MR. REITER: Are you seeing conversations between utilities and the government on the way they aggregate sample data so it'll be more useful?

MR. CRAIG: So, yes, that's a great question. So, we actually ran a workshop for utilities -- well, we ran a couple in association with NARUC -- and other organizations, trying to talk to utilities and provide them with better data and understand what their needs are. I think there has been an increasing understanding that the past is not going to be particularly useful anymore. California has a very large RFP out now for research on climate resilience.

New York is engaging in similar research. You saw Texas using a five-year historic record for cold weather events and they found out that that was not a good idea and so I do think that there are conversations along these lines. I just think that things have changed so quickly that we are a little behind the eight ball right now and really coming to terms with not just what the new data needs to look like, but what those processes need to do.

And actually, I would say Con Ed in New York is one of the leading examples that I believe ICF contributed in their planning, thinking about how they need to use new data and working with climate scientists in that regard, but then also working to improve their planning processes and resiliency analyses.

MR. REITER: Roshi, I see you're nodding your head. Did you want to add something?

MS. NATEGHI: No, I'm in agreement of what Michael is saying and I think the nature of some of our modeling work are aligned, so yes, I was just nodding in agreement.

MR. REITER: So, let me ask you all, generally, do you think that the U.N. climate report has elevated the urgency of the issue for utilities and regulators? Has it sunk into their consciousness yet?

MR. CRAIG: I'll go first, very quickly, not based on any conversations, but I would just assume that having events happening in your backyard will bring the message home much quicker than a U.N. report will. And wildfires, heatwaves, Super Storm Sandy, I have seen a lot of actions that are in response to extreme events, not so much actions in response to the U.N. climate report. I'm sure it helps them understand the problem they face at scale and scope, but I think a lot of these extreme events that you, yourself, have just listed there, as well as others, have really also incentivized a lot of action.

MS. PAYNE: I would say the fact that we had 20 billion dollar disasters in 2021 in the United States, together with an economic toll of those 20 disasters of $145 billion, I think that is probably driving much more than the U.N. report would.

Now, I certainly think in some states, right, the U.N. report -- for the states that are already paying attention, then those states are going to see additional urgency, but of course, that's not all of them.

MR. REITER: Roshi, go ahead.

MS. NATEGHI: I just wanted to agree with what was just said and that based on my conversations with a few utilities, I feel like many have already started trying to be proactive just because they've been very challenged by many different events. And if you just look at the major outage data collected by the Department of Energy, Office of Electricity since early 2000s, you see that extreme weather and climate events since early 2000s have been the main culprit behind major outages. By major outages, I mean more than 50,000 customers being affected or more than 300-megawatt load loss. So, the intensity of weather-related outages has increased by almost 70 percent since early 2000s, so I think the utilities are very much aware of this data. They report this data to the Department of Energy, so my sense is also that they felt the urgency based on the experience, perhaps not necessarily just based on the report, though it varies in different parts of the country.

MR. REITER: So, I'm going to direct this question to Judsen, but I think others may have something to say on this as well.

Based on your interactions with utilities and regulators, do you think they look at climate change impacts differently, the distinction between those that are inevitable and those that may be avoidable, over the long term, by climate change mitigation, like decarbonization measures?

MR. BRUZGUL: That's a good question, Harvey. I think a question that a lot of people are wrestling with is, first, how big an impact is this to my system, right? Just getting a baseline on that is important to understanding, well, what am I doing about it and what are the costs of doing something about it, and then, which of those costs is it prudent to incur right away because I've got a gap against the risk and the risk tolerance that I have set and therefore those are the things I need to take care of no matter what and which are the ones that I might to create some flexibility or optionality to invest in later at a lower cost by making an upfront investment, but there is a lot of uncertainty about the future and that uncertainty is climate related, right, the pace and change of certain climate hazards.

There's uncertainty because we don't have a forecast of the future. As we think about uncertainty, there's a lot of other uncertainty in the energy sector right now. That's part of what makes it so exciting, I think, to work in the spaces. You have massive transformations in the way that we produce and distribute energy, along with the way that we use it in electrification, beneficial application across the sector. So, anything that you are doing to your system to be responsive to adapting to climate needs to be done in the context of those other investments and I think all of that poses major challenges to folks, to utilities, as they think about where to make investments and when.

And I think very few have established frameworks for thinking about that problem rigorously and I'm not aware of -- I think there's only been initial regulatory encouragement to do that. And in the absence of that, much of what's happening, I think, is still at a preliminary level. I'd love to hear others on the issue.

MS. PAYNE: Well, Harvey, I would say that your question assumes that we're going to solve a very wicked, collective action problem and that some of what we're actually thinking may happen is still avoidable, right, and I think that that is probably why, you know, to Judsen's point, we're seeing not necessarily a lot of the conversations framed that way.

I mean I still have environmental law colleagues, very well-respected ones, who just put out an article about how we need to actually plan on a 4 degree C world because of the fact that based on everything they're seeing they don't think that we're actually going to solve the collective action problem that would avoid that, right? So, I think that part of the challenge inherent in your question is how much utilities and regulators can assume that four degree C world is not what they're actually planning for.

MR. CRAIG: And just to do one last bit of level setting. So, the Paris Agreement is either 1.5- or 2-degree Celsius target. I forget which. I think it's a 2 degree C, but 1.5, for instance, is this very extreme, great world in which we could possibly get to that's going to require a huge effort, 2 degrees is still a huge lift. So, if somebody said I want to aggressively mitigate climate change, that would be like a 2 degree C world. It gets worse from there.

Even if we meet a 1.5-2-degree Celsius world, climate change will still intensify over the coming decades. So, a lot of these impacts are coming whether we want them to or not. There's a certain amount of climate change baked in and then it's really almost in the latter half of the century where we can hopefully avoid some of these very extreme outcomes.

MR. REITER: So, that sounds pretty pessimistic. I mean I think part of what we're talking about today is mitigating the inevitable effects of climate change. The question is how much of it is inevitable. I mean we know a fair amount of it is, but in terms of the collective action that you mentioned, Heather, where is there room for optimism on this?

Let me pose a slightly different question. Not only where is there room for optimism, but what do you see as the role of the utilities and utility regulators in addressing this issue of collective responsibility? Do they have the obligation to lobby for changes in law? I mean how far does their obligation, the utilities' obligation, for example, to provide reliable and affordable service tie into their greater responsibility to the community-at-large or even beyond that?

MS. PAYNE: I mean I take a fairly expansive view of what utilities and regulators can and should be doing, right? So, I mean, obviously, I think the first thing is that they need to not be making the problem worse, right? So, you should not be putting any fossil fuel infrastructure into your system at this point, right? I mean if you want to be part of the solution, I actually do view that it's that simple.

In terms of things like lobbying, I mean, listen, we, I'm sure, are all very familiar with the Exxon knew everything that's coming out about the climate disinformation campaign. I think what's not as well known is that EEI actually knew and did lots of studies around carbon as well, right? So, the fact that climate change and utility infrastructure actually being part of the climate change problem is something that has been well known for decades, especially, within the utilities and their regulators and so I think that to be part of the solution does mean that, yes, you need to admit that fossil fuels cause climate change. Its human caused at this point and so you do need to be bringing to your legislators, to your regulators, that you want to be part of the solution. I think that that is something that we should expect of our utilities and their regulators just as being – I wouldn't even say like good global citizens, but just being a global citizen that's where you need to get to, but I'm very interested in hearing what others think about that.

MR. REITER: (pause) Not everyone at once. Well, I imagine we'll come back to this, at least in part, when we talk about affordability during the last segment of our discussion today.

I did want to ask a more practical question about the different types of climate impacts and if you could just briefly discuss your own work on how utilities and regulators prepare differently for some of the events that may be more likely in areas whether it's wildfires or even flooding or sea level change or the impact of heat waves and the like.

MR. CRAIG: Sure. So, I'll start out on this and then I'll turn it over to others. So, actually, I think the EU had some guidance that came out last year, climate-proving guidance. When we think about these different types of events, I don't, as a power system person, care about the event, in and of itself. I care about how it will affect my power system and how it will affect citizens in the United States.

So, for each individual part of your power system, each individual transmission line, each individual power plant, you can go through and catalog the vulnerability of that asset to climate change and that is what the climate-proving guidance in the EU provides a nice framework for vulnerability as a function of what is your exposure to climate change. Are you on the coast and so you're exposed to sea level rise or not? Are you in area where wildfires might be increasing or not? If you're exposed to it, what is your sensitivity to it and what is the risk that you face of something happening in terms of a climate-change related event?

So, you can go through and you can catalog each individual part of your power system to understand what the vulnerability is and that is to be the first guiding part of your understanding of how should I respond to different types of climate impacts. Heatwaves or heat storms, as California called it, are bad, in part, because they can occur over very large spatial scales and climate change, at least out West, will make it over larger and larger footprints.

So, Roshi, earlier on, mentioned compounding events. Heatwaves have this spatially compounded part of them where they can occur over California and neighboring states, so all of their power systems are getting hammered at the same time and it's affecting your demand and your supply in your transmission systems. And so, once you catalog vulnerability at the asset level, you can think about how are those vulnerabilities related to one another, will they all occur at the same time or not, and then, ultimately, think about how will this affect my power system.

And so, once you've gone through that process, once you understand here's the risk that I'm at, then you can start thinking about adaptation measures. You can think about, okay, where can I harden my grid and does it make sense. One thing about wildfires, one of the tricky parts is you've got hundreds, thousands of miles of transmission lines that could be causing wildfires to be affected by them and that's part of the reason why that has been such a challenging problem to deal with out West.

But if you think about a thermal powerplant like in Texas, they've got 100, 200, 300 powerplants in their system and really probably 50 are incredibly important for reliability. And so there Texas has the opportunity to go out to this finite number of powerplants and make hardening investments there, basically weatherproofing them and that can help them avoid bad outcomes under extreme cold events in the future, for instance. And I saw they just sent inspectors out to look at all those powerplants. It's very hard to do that for all miles of transmission lines out West. And so, once you understand the vulnerability, once you understand the joint vulnerability of your system to different effects on your assets, then you can ask a question of how can I adapt and make some hardening decisions and that's really going to vary by types of events and asset-to-asset.

MS. NATEGHI: Maybe I can add. I like it, Michael, how you were approaching it from the adaptation side and maybe I can add a few points on the response side.

So, I worked with a few utilities to develop power outage forecast models for a couple of days before a hurricane arrives, so they can get a map of what areas will be more highly impacted, how long the outage would be, and so on, and that allows them to be more proactive and efficient in response and recovery.

And from that perspective, if you're operating on a shorter time scale, the difference is your ability to predict these events with reasonable degree of accuracy. So, for example, it's much easier to predict hurricane activity compared to wildfires or ice storms and that the nature of your inability to predict the impacted area or the speed at which it happens or ice accumulation on your power lines that really challenges the utilities in their ability to rapidly respond.

And the other part, actually, as Michael was mentioning as well, it's different events have varying degrees of impact on different parts of your power system. So, for example, after most hurricanes -- I mean not the very intense ones – or floods the majority of their impact is on the power distribution system that have maybe a less lengthy/complicated recovery process compared to the transmission system. And I haven't done a whole lot of work on wildfires, but I was reading how, Michael, you were mentioning as well, a transmission system's expsoure to wildfires is particularly increasing under climate change and those aspects of what parts of your assets are more vulnerable to different types of disasters also affects your ability to respond in a reasonable timeline, but yes, coming at it from a shorter time scale.

MR. REITER: So, I -- I'm sorry. Judsen, were you going to say something?

MR. CRAIG: Go ahead, Judsen.

MR. BRUZGUL: Go ahead, Michael. I'll let you respond.

MR. CRAIG: I was just going to quickly say actually on our lab website, assetlab.org, we have a handbook that we put together as part of those workshops to try to walk through the vulnerability assessment and talk about the different climate impacts. So, before I forgot, I just wanted to flag that in case people want to learn more. It's in the Students Accomplishments tab.

MR. BRUZGUL: I'll just say I wanted to add -- I agree with everything that was said and Michael did a great job of laying out that perspective on assessing vulnerabilities and I think alluded to -- both Michael and Roshi alluded to the customer and differential customer consequences, if you will, and I think that plays into the kinds of prioritization of investments, as well as the types of investments that are possible. As you think about differential vulnerabilities, we saw a lot of this play out in the Texas freeze. For example, through the headlines you saw disadvantaged communities be significantly impacted for a variety of reasons. You see it in heatwaves. You see it during major outage events. And I think moving beyond just understanding which customers are dependent for medical device reasons and which ones are fire stations and police stations to a more sophisticated understanding of vulnerability of the customers they serve is an important direction to add to the conversation around understanding vulnerabilities and what to do about it.

MR. REITER: So, we're going to turn in the next segment to talking about some of the analytical tools and touching on, at least, some of what Michael was talking about, but I do have a couple of questions --before we close out this segment --from the audience.

My first question is from Michael Kessler. And he asked if the panelists could discuss how markets and specifically RTO markets may or may not be able to effectively address climate change by including, for example, carbon pricing and market clearing prices.

MS. PAYNE: So, I'll start on that one. And FERC did a technical conference last year around carbon pricing and I think that there's still healthy debates on whether it would come in under a Section 205 or 206 filing, but I think that most likely what we will see is we will see an RTO like PJM, probably, or New York ISO and New England ISO actually put forward a filing where they would include carbon pricing in their clearing price and then, I think, that that's when we'll actually see whether that is accepted. I do think that that is something that FERC could allow, but based on what we're seeing today, obviously, it hasn't happened yet.

MR. REITER: So, the next question I have is from Jorge Roman-Romero. And he asks -- actually, asks two questions. What policies or laws will aid utilities to respond to climate risks from the state and federal level? And for purposes of decarbonization, is it legally and economically feasible and practical to adopt a carbon credit system for electric power at the household level, that is, for consumers?

MR. CRAIG: So, I'm going to give a high-level response, nothing concrete, so you will not get anything useful out of this, but I do just want to flag that right now we're talking mostly about adapting to climate change. Of course, mitigation is this other big theme that is ongoing in the power system and one thing that I do not think we have any sort of handle on is how much these two can align or not.

We did a study last year for the southeast United States and we were looking at adaptation and thinking about, okay, if I build more wind and solar in my system does it help me with adaptation or not because these other new technologies that we're building, renewables, nuclear powerplants, carbon-capturing sequestration powerplants, they all are not invulnerable to climate change. They have their own vulnerabilities. Solar panels, for instance, are affected by wildfire smoke, so they had huge generation penalties last year during wildfire season and they are less efficient at extreme heat.

So, I think when we're thinking about how we should be mitigating climate change there can be co-benefits in your adaptation, but these are things that we need to think of together rather than separately. These are long in advance. That's 20, 30, 40 years, so they're going to be around as climate change intensifies. And so, in general, I would say we need to think about these together. And a carbon price, for instance, that pushes investment toward low carbon technologies, does not necessarily make you more adaptive to climate change. You could be putting nuclear powerplants or carbon-capturing sequestration powerplants in places on the sea or on rivers that in 10 or 20 years are not going to be good for cooling that are going to be affected by sea level rise. And so, I just want to flag that mitigation/adaptation, adaptation does not naturally lead to mitigation. They need to be done hand-in-hand and so whatever mitigation policies you put in place are not necessarily going to help you adapt.

MR. REITER: And what you just said, Michael, for example, if you're talking about decarbonization and you're talking about adding more solar, for example, large-scale solar probably has a significantly lower unit cost than rooftop solar, but in terms of restoration of services and the like there may be some advantages to local fuel cells or rooftop solar or the like that would be less vulnerable to changes in the climate. Is that part of what you're saying?

MR. CRAIG: Partly. I mean I think I would frame the distributive versus centralized more as Judsen spoke about, which is there are certain communities that are going to be more vulnerable than others and so can we think about distributive energy not as like mitigate first, adapt second, but as an adapt first, mitigate second tool. And so, thinking about where we need to put rooftop solar, along with grid, other storage, maybe even a diesel genset in order to provide adaptive capacities to communities that lack them, to me, would be more important than thinking about rooftop solar versus centralizes solar or mitigation potential.

MR. REITER: Any other responses to the last question before we turn to our next segment?

MS. PAYNE: I'm not sure that I quite get the question, whether is it legally and economically feasible and practical to adopt a carbon credit system for electric power at the household level? I mean I think the one thing that I would say is that, for example, California has a cap and trade system that's based on carbon for power as well as additional industrial segments. And basically, every single person in California twice a year gets a credit on their electric bill that's tied to that cap and trade system. So, if that's what it goes to, then yes, at least at the state level.

MR. REITER: So, with that, Heather, we're going to turn next to our discussion of some of the analytical tools. And Michael, I think, touched briefly on some of those. So, let me just open up, generally, the question of what are some of the analytical tools that utilities and regulators are utilizing right now in system planning to help them plan for climate change and related events?

MS. NATEGHI: So, I can chime in briefly. As I mentioned, I worked with a few different utilities to develop predictive models of power outages ahead of some extreme events. And based on my conversations, it seems like at least most of the utilities that I've talked to, they have a meteorologist on the team, so they have access to some type of weather forecasting capability at various scales.

What I often find missing is a model that translates the climate impact to infrastructure impact. A lot of times I think that translation happens based on expert's knowledge, which would've been fine if our climate system was stationary, but that translation based on gut feeling as opposed to a data-driven way which is guided by the physics of the infrastructure is not always helpful. And I'm curious to learn from other panelists and others.

MR. REITER: So, let me turn to Michael. So, what are some of the analytical tools that you have used or working with regulators, governments to utilize in this area?

MR. CRAIG: Sure. So, I talked about the vulnerability assessment already. I do think that utilities are increasingly adopting that. Con Ed in New York, for instance, has their climate resilience or adaptation plan that does a vulnerability assessment. The EU has their climate-proving guidance so that you're engaging in this as well. So, I think that's the first step. I've already talked about that.

I think, otherwise, a lot of the approaches are taking existing tools that utilities have typically used to plan and putting new data into it. I have not seen any utilities radically revising their planning processes and so when I talk about planning processes I'm thinking of, for instance, a utility releases an Integrated Resource Plan or an IRP. And for that, they had this long-term power system model where they look out 5, 10, 15, 20 years into the future and say what assets do I build, where do I build them, when do I build them? And all of that is in order to minimize system costs while meeting other constraints like whatever decarbonization target they had, if any, and while ensuring reliability.

And so that kind of long-term, large-scale power system model that is where they might be feeding in new data rather than looking at the model itself and thinking about how can we reform it. I do think there are really exciting options for changing the process rather than just changing the data and those, to me, of most interest are things like robust processes where you think not how well would this one asset do under climate change or not, but asking how robust is a certain investment across a wide range of future climate outcomes because we have uncertainty, not just in terms of the emissions pathway, so not just in terms of how much the future will warm, but there's also tons of uncertainty in terms of if the world warms by 2 degrees Celsius by 2050 what does that mean for my local meteorology and impacts. And so, that is in the academic community what we talked about is deep uncertainty. Rand Corporation does a lot of robustness and so it's with that deep uncertainty in mind you don't even know how to think about the distribution of the potential outcomes where we can have some of these robust tools that are testing the sensitivity across a very wide range of future outcomes that I think could be very valuable, but I just have not seen uptake yet. Although, I don't IRPs all day, so this is based on the limited set of IRPs I've read.

MR. REITER: So, let me turn to Judsen because I know, Judsen, you have worked with Con Ed and Michael had just mentioned them. Not only with Con Ed, but with some of the other utilities and government entities you've been working with, what types of tools are they currently utilizing and what are the different types of tools for different types of events that are the most practical?

MR. BRUZGUL: Yes, Harvey, let me try to answer that. So, yes, we were the prime contractor to support Con Edison on their work with their vulnerability study and a subsequent climate change implementation plan that really took a deeper dive into ways to change processes and the planning that they do to help incorporate changes in climate.

So, I would say I very much agree with what Michael and Roshi were saying in terms of analytical tools, things like outage forecast models and the kind of modeling that goes into integrated resource planning. I think that continues to be important. In California, they incorporate some gradual climate change in their forecasts that are standardized for use in their Integrated Resource Plan, so there's a bit of integration there. That doesn't necessarily translate into the kinds of things you want to know for hardening your assets and the conversation that we've already been having, so I think that there is a gap when it comes to that.

What I would say is -- those tools, just as Michael said, I think can be helpful in understanding things like how temperature could impact future generation supply, as well as demand and load, so I think there's work that can be done.

We did some work in Ghana looking at an Integrated Resource Plan where we rather than take a least cost approach, we looked at a least regrets approach where we were thinking about this robustness that Michael refers to and I think that is an important way to reframe the application of some of the tools. It does require maybe using them a little bit differently. We were looking at drought scenarios, for example, that weren't traditionally part of their Integrated Resources Plan.

The other thing I want to mention is -- picking up on Michael's comment about deep uncertainty and robustness, one of the things that we've been working with utilities on and in California has been picked up in some of their guidance materials is an approach called adaptation pathways and that is meant specifically to help plan in the face of deep uncertainty. It's one of several techniques that's been developed in the academic literature looking at how you think about the sequencing, the timing, and importantly, the triggers or signposts that tell you about how the future is evolving and what that means for the next investment that you want to make to follow a path that maintains your risks and provides an outcome robust to the changes that we're seeing.

And so, that's actually a technique that can be applied. It is being applied as part of planning and investment decision-making to think about in a new way if we have an uncertain future driven by the things that Michael was alluding to, how do we actually take action and not just wait and see or wait to see what manifests, as we were talking about earlier. So, I think that the work on adaptation pathways has been -- and applied in the energy sector is something that we see at the frontier of things that are useful in this context.

The other thing, just to mention, and Michael alluded to this a little bit, is something that Con Edison work in New York really did provide good information broadly, right? A lot of this is happening, we should say, at utilities not in a public way, especially if there's not a regulatory proceeding which is requiring that disclosure. So, just make sure everyone's clear that that's part of why exactly what's known and exactly who's doing what is often confidential.

I would say, though, when it comes to thinking about the way that they're designing equipment into the future and the power of a design standard in any infrastructure -- we see this in New York City, for example, thinking about the building stock across New York City and design standards to help them think about changing temperatures and flooding across the city.

Con Edison similarly looked at the importance of a design standard that helped them anticipate not just today's climate, if you're investing in a new asset, but the climate over the lifetime of that asset. And for renewables it's 20, 30, 40. For transformers, it could 40, 50, 60, 80 years that you see a new substation in service.

So, thinking about incremental change that goes into the design of that asset, as it relates to temperature, as it relates to things like sea level rise, and coastal flooding and actually setting for engineers something that allows them an input to their traditional design and build models.

And I think that's a case where I would encourage the need for continued thinking about more adaptative design in the way we actually build infrastructure, but as that's happening engineers traditionally wanting that historical view of a number to build to, a design standard that incorporates forward-looking climate can help achieve something meaningful in the near term. So, I'd highlight a few of those examples.

MR. REITER: Well, let me just ask a follow-up question about design standards. When engineers talk about the desirability of having those for planning purposes, do you differentiate between design standards that would apply to specific types of technology as opposed to performance standards because I think there could be a big difference in the flexibility it affords entities to best adapt. Is that something that comes into their thinking?

MR. BRUZGUL: I think from the point of view of the utility, or the work that we've done anyway, it's less about -- it's more about the project outcome and actually designing -- you know how many feet should we elevate the substation transformer bank to achieve the broader goal that maybe, I think, your question, Harvey, at least in my mind, raises up.

Broadly we might want a certain system performance against traditional reliability metrics or other metrics that capture resilience a little differently and how you achieve that could come through a lot of different solutions.

I see that as a slightly different set of discussions from the design standard itself. I think it's an important one and relates to maybe your initial choice of investment, but once you have chosen you are going to pursue a new substation or you are going to do pole replacement or other things, understanding then, well, what standard should we build to and how does the standard of the past maybe show us to be insufficient as a standard we want for the future, that is where these design standards come into play.

MR. REITER: So, I wanted to ask a slightly different question of Heather with respect to the analytical tools that may be at the disposal of regulators and policymakers, and I'll open it up to others too, as well. What responsibility do regulators have to encourage or mandate best practices in this area?

MS. PAYNE: I think that that's a challenge because the specific discretion that each set of regulators have, right, is going to be based on state law in a lot of cases and specifically what they are tasked with and how specific that is. If their discretion is broad, then, obviously they can require those best practices.

I think that the other thing that certainly I'm picking up from both Michael and Judsen, though, is that even if regulators might not specifically want to request that of their utilities, of course, part of the way that that can still happen is if we have interveners in these different procedures, right, or dockets that would request that and simply ask specific questions of the utility around how they're doing this planning.

And I think with that it's really telling how little truly minuscule public participation we tend to get, especially in IRP dockets. I mean, yes, there are some notable exceptions, the South Carolina IRPs last year were notable exceptions, but I have looked at lots of IRP dockets where you have all of two filings. You have the initial plan that the utility put in and you had the Order from the PUC accepting or adopting it and that's it. There is nothing else in that docket.

And so, I think that one of the other things that communities that are interested in these issues and how climate change might be impacting their utility planning is actually finding a way to get involved in some of these dockets which can be exceedingly, exceedingly challenging. I mean I think we're starting to see a little bit more outreach, especially toward underserved communities, but it's something that I think regulators need to work on is really finding more ways to have communication for people who are interested in these topics.

MR. REITER: Just for the court reporter's edification, IRP refers to Integrated Resource Plan. I don't know if anybody else wanted to weight in, if not, I'll move to another question I had in this area. (No response.)

MR. REITER: So, one thing that I think we've touched on is the interrelationship between actions that utilities can take and actions that governments take, more broadly, with respect to decarbonization, for example, but also with respect to mitigating the impacts of climate change. We're not just talking about keeping the utilities running. We're talking about making sure the bridges stay up, that roads don't get flooded. So, how is it that the interrelationship between utility planning for mitigating climate change impact and improving resiliency relate to the broader planning by federal, state, and local governments to deal with climate change impacts and are they doing enough?

MR. BRUZGUL: I can comment a little bit if no one else wants to start. I feel everyone took a step back with that one, Harvey.

There are a couple of things come to mind with regard to this question. And to your last point, are they doing enough? No, I don't think there's enough. I think Heather makes a great point about the involvement in the rate cases. I think, in general, this coordination around what people are doing in a community around resilience remains a challenge and I think engagement and working groups working together are really an important aspect that can provide benefits, but there's just not that much of that happening.

One of the things that we saw in New York related to this, so first of all, the Con Edison work did have an active working group. The city was very involved with the work that we were doing with them as part of the vulnerability study and there were dialogues. I won't point them directly to the work within the climate change vulnerability study, but there were certainly dialogues within New York about how, for example, the storm water management system might relate to a vulnerability of an asset within the city, be it Con Ed or others, right? There is this interplay.

The city is investing in a large coastal flood mitigation project on the east side of Manhattan. What does that mean for assets that are either behind that protection and the responsibility that the utility has? Does the utility need to assume that that project will happen and so they're not going to harden their own system or do they need to assume that it won't happen and harden their own system? I think that kind of coordination is really important because, look, that's the sort of double spending that costs society more when it's lacking.

And in general, we're really at the, I think, starting point for those kinds of coordination and conversations and that's just thinking about the energy sector. The other thing to point out, and I'm sure others on the panel would chime on this, right? Coordination with other infrastructure is crucial as well and the interdependence of the energy infrastructure with water and telecom and transportation and others is really, really important.

So, what you are doing to adapt and mitigate risks in one might not do anything if all of a sudden you can't -- just as you were alluding to, Harvey, you can't access your substation because the road hasn't been maintained to be ready for future flooding or so many different interdependencies with storm water, with waste water treatment plants, and with telecom and you're relying on being able to reach customers via a telecom system that wasn't as resilient as you had anticipated.

All of those kinds of things are -- we're at the start of those kinds of conversations, as I see it, but one other thing I wanted to point out is, I think, on a federal level things like the FEMA, which I know has already been defined in acronyms, BRIC, which is Building Resilient Infrastructure and Communities grant program that is funding that goes to the states that can then flow to local communities for proactive investments in risk mitigation and in resilience that needs to incorporate consideration of future climate as part of the FEMA guidance. It also works to have partnerships between a local government entity and something -- either a municipal or an investor-owned utility to carry out those projects. And so, there's a place where significant funding, a billion dollars of funding flowing to addressing these issues that provide opportunity for folks to coordinate I think is a success story and I expect that there will be a lot more funding through that mechanism.

MR. CRAIG: I just want to add one thing. I'll defer to my co-panelists on whether more needs to be done. I assume the answer is yes, though, and this is one area where mitigation and adaptation can go hand-in-hand. A drum that we always beat for mitigation is regional coordination is important. California has their energy imbalance market where they're trying to bring in power from the Western United States, basically, and they import power from far away to get at those renewable resources.

In the East, we similarly when we think about how do we decarbonize the eastern power system, most of those plans rely on importing huge amounts of renewable electricity from out West, like the Great Plains area into the Eastern Seaboard where we don't have the renewable resources. And so, just the mitigation side of things requires a lot more interregional coordination to figure out how do we build those transmission lines and how do we operate a system that spans multiple Regional Transmission Operators or RTO, like PJM and MISO, for instance, coordinate.

So, we have that need in mitigation and that expansion, thinking about larger and larger regions and coordinating those operations and plans. That is one area where you can get a lot of benefits in the adaptation space as well. Because of these extreme events that are happening over larger footprints, you want to be thinking about how can I get more diversified assets that might be less vulnerable to the same type of climate event. And one of the ways you do that is by coordinating with your neighbors and thinking about, okay, if I have a heatwave can I come and borrow power from you.

MS. PAYNE: Yes, I would say that both of those, actually, really demonstrate, I think, one of the challenges with your initial question on more needs to be done because we don't really have a federal energy policy and we try to get around that a lot of different ways. Maybe it'll get better. I think it was looking far more hopeful for that a year ago than it is now, but I think especially Michael's point brings out that a lot of this would be easier with a lot more transmission and if we actually had federal energy policy that was explicit.

MR. REITER: Let me ask Roshi a question on this. And actually, it's prompted by seeing Michael's Carnegie Mellon diploma in the background. Jay Apt ran the Electricity Center there. I remember him talking -- this was before the Energy Policy Act and the reliability rules and enforcement authority that went to FERC. And he was talking about how we recover from disasters. He wasn't talking so much about climate disasters then, but he was saying what happens when we have an inevitable outage. We can't prevent them all.

If you have tall buildings and we have an outage, how do we keep the elevators operating, how do we keep traffic lights operating? Should we install solar panels on a small scale? With local government, can its zoning control do it?

Roshi, I know you're working with DOE now and they're looking at energy efficiency and also performance standards. On that smaller scale, can that have a beneficial effect on the intersectional issue between government and the utilities?

MS. NATEGHI: Sure. I'm not sure how well I can respond to this question. Firstly, I'm still learning a lot about various different efforts that are happening at the DOE. So, I'm learning my way around there for now.

But if you don't mind, I would like to maybe circle back to some of the comments that the panelists were raising and they were making me think of all the challenges and all the work that needs to be done. And as Judsen was mentioning, so there's already quite a lot of coordination happening between federal agencies, FEMA and DOE with utilities, especially when disasters happen.

But then, my understanding is -- so you were mentioning incentive to mitigate for different states. My understanding is even those coordinations or policies that are in place need to be rethought more for example, for FEMA to release some of those funds to different states, the damage needs to be a certain dollar per head. So, if the amount of damage does not meet the threshold, you won't get the cost share that is suitable for your recovery. So, in a way, you're encouraged not to mitigate and sustain a lot of losses to be able to qualify for that funding. I know that there's lot of efforts there to rethink some of those allocation policies.

And to Heather's point about lack federal energy policy and a lot of the panelists already talked about different reliability or performance metrics of the power distribution systems and bulk power system. My understanding is a lot of these reliability metrics also, again, I'm probably just repeating what has been already said, but these reliability metrics are also calculated based on historical data. They don't really characterize future risks, including the climate risk, right?

And then even if that wasn't the problem, there's really no accountability, is there, for missing certain performance targets. So, as the panelists were talking, I was like, oh gosh, yes, there are so many challenges and so much work to do. But taking your point about technology-specific investments that I need to read and think about and maybe get back to you.

MR. REITER: Okay. Maybe we will get an article out of you in the Journal.

MS. NATEGHI: That sounds good.

MR. REITER: So, I'm going to take our topics out of order and I want to turn to the affordability question before we talk about what some of the regulators are doing around the country and internationally, so let's turn to this question of affordability. And I think it's something all of you have touched on directly or indirectly that we've got kind of a regulatory triage problem that we will have to deal with where we have long-term impacts of climate change and immediate interest in mitigating harm and keeping their systems resilient.

So, what are the responsibilities of the utilities and regulators for weighing the different costs for resiliency and longer-term mitigation and how do that strike that balance? How should they strike that balance? Let's just start with that question.

MS. PAYNE: I mean that is one of the biggest challenges that regulators are facing throughout this, right? We all know that transition and the transformation of our electricity system is not going to be cheap.

For my perspective, I think that there's two things that regulators should focus on. The first is that we can use existing programs I think more efficiently than we do. So, if we think about energy efficiency programs, right, yes, I can go to my local Home Depot and energy efficiency money will make it so that I can purchase reduced-priced LED lightbulbs.

I don't think that's necessarily the best use of our energy efficiency funds in the State of New Jersey, right? I think that we actually should be funneling all of our efficiency money to address the energy burdens that we know exist and are much, much, much more important, in my opinion, than us making LED lightbulbs some percentage cheaper.

And so, I think that there are two different problems for regulators, in my opinion. The first is look at the programs that we have. Look at the money that we're already spending on things like energy efficiency programs and let's actually repurpose those programs really to make it so that the energy burdens that we know exists can be minimized to the greatest extent possible.

The other thing that I think needs to happen is we do need to have more of a conversation within regulators and utilities about, okay, if we have a vision of where we're going, if everything that we are currently doing does it all still have to be done or as we make that transition are there things that we should stop doing or not do, given what we think that end state is going to be and save money that way. And that's a conversation that I have never actually really heard happening because it seems like the idea is always that we always have to keep doing everything that we are currently doing and then we add stuff around the energy transition on top of it.

And so, I think that we actually need, basically, to start from the bottom up and say what do we still need and what realistically needs to go. In a lot of circles, this is usually done through something like zero-based budgeting. And I think that it's time for us to start having those kinds of conversations within utilities to really see what we can do to minimize the cost of the transition to make it so that we could actually minimize those energy burdens since we know that they exist.

MR. REITER: Let me as you a follow-up question. One is when you talk about repurposing the funds -- it's going to be a two-part question -- where would you repurpose them? And if you still want to encourage people to switch to LED bulbs or other energy efficiency measures, can you do that or should you do that through decoupling devices in setting utility rates so that they have an incentive not so much to sell electricity, but to meet certain targets that would achieve some resiliency goals, as well as efficiency goals?

MS. PAYNE: So, no, I'm not really a fan of decoupling and that's probably too deep to get into in this conversation. How would we repurpose it? Well, I think that some of the main ways would be to focus on low-income programs where we could actually do a lot more good with that money to reduce energy burdens, right? So, we have a very high percentage now of residential smart meters in the United States. We can couple that data with other population metrics and actually start targeting much more than we are now to make it so that energy efficiency improvements will help those that are most in need.

MR. REITER: More of a means-tested type of --

MS. PAYNE: Exactly, much more than we are now, yes.

MR. REITER: So, Judsen and Michael, I know you both touched on these things, so let me ask you about what types of things the utilities are looking at? How are they making some of these decisions, these tradeoffs between decarbonizing and ensuring reliability?

Michael, let me just start with you because I know you talked about some of the complicating factors in even making these judgments because you've got measures to decarbonize that are going to exacerbate some of the problems with restoring or maintaining resiliency at the same time.

MR. CRAIG: Yes, I'm actually going to put up two -- in my mind, actually, that are most relevant to regulators and then I'll turn it over to Judsen and Heather and others can swat down what I think is an issue if they don't think is an issue. But first of all, what was driven into my head in all my regulation and law classes about the electric power sector is beneficiary pays, meaning if I make an investment, I should not make everybody pay for it, especially those who don't benefit at all from it. The people who benefit from the investment should pay.

But you have situations where now people who are most impacted by climate change, wildfires are a perfect example, are exposed to tremendous costs in upgrading the grid and those same communities might be the least able to fund it. So, if I have a rural community in Oregon that is now facing public safety power shutoffs, I can underground that line. The undergrounding of the line really only benefits that community or to a vast extent benefits that community. It's going to cost millions of dollars. Can that community pay for it? So, I think that is a challenge, to me, in terms of how we think about regulating and distributing these costs.

I think the other issue is there are some principles by which a public utility commission determines whether to approve or deny plans from utility and that is rooted somehow in the public interest. I want to mention that you're spending money that is going to be in the public interest that passes some cost benefit analysis test or some other test.

If we think about the future, the benefit of any climate adaptation investments are uncertain. Some of them are extremely uncertain. And the benefit of any investment has always been uncertain to some extent. The benefit of building a gas generator is uncertain because I don't have perfect foresight of gas prices. But there is this new element I'm deeply concerned about what future climate will look like, what future climate impacts will look like, and what the benefit of climate adaptation investments will look like that I think can complicate that cost benefit procedure and how will a utility and a regulator interact with one another. And for the regulator to figure out whether this investment is actually good and a robust, adaptive investment or an investment that seems to be good at first glance, but in reality is not going to provide value.

So, to me, those are two larger issues that can complicate how regulators view adaptation investments and how they think about approving or denying them that I think are a challenge for some of this coordination.

MR. REITER: Roshi or Judsen, do you want to add anything?

MR. BRUZGUL: I just agree, Michael, with your comments. I think what I have seen mostly --so, backing up for one second. I just want to say on the utility decision-making around tradeoffs between mitigation and resilience, by and large, what I have seen is that these conversations within the utility tend to be pretty siloed still. So, I don't know that they're fully really grappling with what it means to trade off these dollars. I don't think we're seeing that yet.

On the question of the beneficiary pays, I do think we have seen some examples where regulators have denied requests for things that might build resilience like a micro-grid, for example, where a certain community would benefit from that, but the justification for why the entire rate base should fund it wasn't sufficient.

My impression is that folks are increasingly moving towards, maybe slowly, a more open mind about how to interpret that and think about that from the point of view I think the level of connectiveness within society, in a way, and across a customer base in that there are arguments to be made for how the benefits to one community spread more broadly than just that community. So, I think that there's economic techniques to help support that.

I think there are ways to improve benefit costs analysis and rationale that can make it easier for a regulator to see those benefits and in protecting the best interest of the public still approve those kinds of investments. I think that there's more to be done there, but I'm maybe optimistic that there can be work to be done.

I think on this question of understanding benefits that Michael raises, especially the timing of benefits, if you're planning for a low probability event and that's where you're going like avoid billions of dollars of damage it's 1 percent annual chance flood, when do we get that?

I think there are some techniques that are different from just a simple benefit cost analysis ratio that help think about that little bit differently, things like break even approaches, but it's a challenge. And I think accounting for the benefits in a way that articulates the full range of benefits again, in a cost benefit framework or other framework that the regulators have established remains a gap, again, an area for work. I think I am optimistic on that front as well, though.

MS. NATEGHI: Maybe I can briefly follow up on also important points that were raised by Heather and I'm reminded -- like I recently read in an article that was raising the fact that despite the federally-funded energy system programs that we have, like the low-income home energy system program and the weatherization assistance program they've been around for over 50 years, spent billions of dollars in assistance and yet, one in three U.S. households are considered energy poor. So, the article was also alluding to the lack of effective metrics to evaluate and track success and more systematically invest in a way of alleviating energy poverty as opposed to addressing in a piecemeal way. So, I just wanted to mention that as well.

MR. REITER: That was a segue to a question actually that I was going to ask about, which is when we're talking about affordability, one component, in fact, it's part of President Biden's Executive Order, is that, at least at the federal level, regulators have to look at the impact on disadvantaged communities. And so, how do we integrate our analysis of affordability, not only in a general sense, but with the goal of making sure that poor communities don't take the brunt of some of the mitigation measures themselves, but what role do you see utilities playing? Have they thought about this and what are regulators looking at or what should they look at? So, I just open that up, generally to the panel.

MS. PAYNE: I mean I think that that's going to take a very state-specific focus really based on the state. I know that certain states --like California has a fantastic environmental justice mapping tool, for example, that I certainly hope utilities would, along with everybody else, be using.

New Jersey has a specific EJ law that went into effect that does limit where you can site specific facilities as well and so I think that we're going to see more and more of a focus, Harvey, not just on affordability, but really on the impacts of infrastructure as well.

MR. BRUZGUL: I would just add on that to build on the California example, California had a proceeding specific to climate adaptation where they resulted in a rulemaking requiring the investor-owned utilities in California to do a climate vulnerability assessment and also along with that is to build out a very robust community engagement plan such that the disadvantaged and vulnerable communities, as they term them, the DVCs, which take into account the tools that Heather was describing, plus some other factors to understand where these communities are within their territory to do significant engagement with them as part of input to their vulnerability assessment, as well as shaping the investments that would come to address those vulnerabilities.

I think there was a lot of dialogue during the proceeding around the importance of consideration of the disadvantaged and vulnerable communities and the resulting Order, I think, really does a lot to highlight this issue and I just wanted others at least be aware of.

MR. REITER: It would strike me, even when we're talking about resiliency, that some of the measures that utilities would take if they were trying to put their dollars where they would be most effective a lot of times what they'd be guarding against, let's say, with respect to flooding in low-lying areas some of those are probably going to be some of the areas where some of the poorest of the population already reside and so reinforcing the system to withstand flooding or other similar events may also incidentally be most directed at the poorest that are most likely to be impacted.

Does anybody disagree? Do you think that's a correct observation or am I generalizing?

MS. PAYNE: I think that's especially true for inland flooding, but Michael probably has more detail around specifically that than I do.

MR. CRAIG: No, I was just going to mention, in terms of heatwaves, I think there's been very nice work recently. There was an article that came out maybe three months ago, looking at extreme heat under climate change and how it affects urban areas differently. I know it's written up in the New York Times earlier in the year. The New York Times had this nice article about how the heat island effect has a more concentrated impact in areas that are generally low income, looking at Georgia and Richmond and other cities. And so, you can imagine during outages you have more impacts.

And I believe Roshi mentioned the Chicago heatwave and there's a wonderful book -- wonderful in that it's a very nice book writing about a very terrible subject on looking at who of those hundreds of people who died, who were they, what was really the reason that these other ones who perished during that heatwave was often low-income individuals or the men who were isolated and alone.

And so, yes, there's all sorts of compounding factors here and so that adaptative capability that I think is a very important thing to consider when we're thinking what our assumptions are about reliability in the power system and making sure that, okay, our assumptions might be wrong because our assumption is based on history and no longer representative of what will happen in the future. So given that, how can we make sure that these communities that don't have much adaptative capacity can have it.

MR. REITER: Well, I'm going to – unless anybody else had something else to add, I'm going to turn to our last topic area and hopefully we'll leave a few more minutes for general questions from the audience.

And I really want to focus on a couple of things dealing with how regulators are responding around the country and to some extent internationally to deal with issues of climate change resiliency and mitigation.

We spoke before this conference in some of our discussions here about what we've seen around the country. So, I'm going to turn first to Heather to talk about what the legal framework is when we're talking about companies' failure to act on foreseeable consequences. And I know that there's been some litigation in New Orleans in the aftermath of Hurricane Ida and there's also been significant litigation in California in the aftermath of wildfires. So, I wonder if you could talk about the legal landscape there and what obligations utilities may face and what standards they have for prudence or other types of litigation risks if they don't take proactive measures.

MS. PAYNE: Well, I think that there is-- this is, again, one of the areas that makes energy law so interesting because we do tend to see different legal requirements and different standards in different states. So, of course, in California, we're seeing some litigation based on gross negligence, but we also have a very unique inverse condemnation law in California. It doesn't exist anywhere else in the country, so IOUs in California have a different legal paradigm that they're operating under.

I think that the Entergy litigation is going to be interesting more because of some of the previous statements of the utility. So, when they went to the New Orleans City Council to get approval to build a new gas plant, part of the justification was the fact that this would have a black start capability and would really enable the city to be much more resilient from a storm. And of course, with Ida we didn't see that and so I think that a lot of the litigation in New Orleans is really focused on past statements that were used to justify additional infrastructure.

For the most part, utilities are not going to be held liable until they meet a gross negligence standard, right? And so, I think that that is a fairly high bar in terms of plaintiffs actually suing their utility. I do think, though, that we are going to start seeing more of a regulatory focus. Not so much from lawsuits, but for a regulatory focus, to your point, Harvey, on prudence. And so, what is going to be found to be prudentwhen we're doing a review may end up being different. And I think it's still an open question, both at the state level and then for federal regulators. For example, the Nuclear Regulatory Commission, NRC, how much they're going to take the work that Michael is doing, specifically, into account, right?

So, we actually saw a very interesting situation with the relicensing of the Turkey Point Nuclear Plant where NRC didn't necessarily, in the feeling of a lot of views, take what is going to happen to that plant likely within that relicensing period into account. Where that's going to come up in prudence determinations as utilities try to move specific infrastructure investments into rate-base is still a very, very open question.

MR. REITER: So, I know there are a lot more things that we could discuss. I have a bunch more questions, but we're running near the end of our time. I did want to leave an opportunity for participants to ask their questions or people in the audience. So, if you raise your hand, just hit the raise your hand button at the bottom of your screen, we can open your mike so you can ask questions directly of the panelists. So, why don't we do that for a couple minutes now and I'll look for any of the questions that we have.

MS. PAYNE: I did also, Harvey, want to make sure because I don't think we're going to actually get to much of the climate change litigation, but if people are interested in what is happening in terms of climate change litigation around the world, as well as in the United States, the Sabin Center at Columbia has a fantastic online resource that really can provide both a great overview and then also does a deep dive into all of the cases. So, that resource is available if people are interested since I know we're not going to get really into that at this point.

MR. REITER: Yes, I think that we've got a lot of shy attendees. You wouldn't know it most of the time, so I will use that to ask one more question from the panelists, though, and it really was prompted by some observation that you made earlier, Heather, about the continued availability of incentives to install gas-fired equipment in the home.

And so, the question I have is we have a number of states, most states, in fact, where natural gas is available where the public utilities laws require the gas utilities, like the electric utilities, to provide service on reasonable requests to newcomers as well. How do we deal with this issue, the one you talked about, and how are utilities thinking about it?

I know we'll be seeing some articles in future editions of the Journal about gas utilities, gas distribution companies and pipeline converting their infrastructure to move hydrogen, but how do we deal from an equity standpoint for people who already have this equipment – an affordability standpoint -- and the political issue of dealing with industries that employ a lot of people and that have a lot of infrastructure in the ground? How do we deal with that if we're also talking about longer-term climate change impacts that require more decarbonization? So, just a small question to end the session. Michael, I see, was throwing up his hands. I don't know if that's the answer he gave.

MS. PAYNE: I mean I know that for me I have two papers that bear directly on this. One I've already mentioned, so Natural Gas Paradox actually does talk specifically about how regulators should be thinking about shutting down the natural gas distribution system.

And to your point on the duty to serve, I actually have another paper, the draft is available on my SSRN author page. It's coming out next month in the University of Richmond Law Review called Unservice, and it specifically deals with the fact that we will need to modify the common law duty to serve, which is what you're discussing to deal specifically with these issues.

And I think we'll start seeing that with natural gas, but I actually think that as climate change becomes more extreme natural gas utilities will not be the only ones that are faced with situations where it's going to be very, very difficult to continue service.

MR. REITER: So, let me open it to our panelists for any closing remarks they had, any last thoughts they wanted to provide before we end the session.

MS. NATEGHI: I want to thank you for organizing this and thank all the panelists. I learned a lot.

MR. CRAIG: And I would echo that. It was great. I just put links in the chat. One to another Sabin Center report actually on climate resilience that is great and then I put a link for a handbook as well, so a couple more resources. But yes, it's been great and thank you for coming.

MR. REITER: Thank you so much, Michael.

MR. BRUZGUL: Same from this side. Thanks so much. It was a great panel. I learned a lot from it. Thanks Harvey for some great moderating and good questions to keep moving. I would take away that these are important topics that have, I think, real challenges. There's a lot of work happening on it, but there's much more to do and I'm excited for where this will take us.

MR. REITER: I want to thank all of you for taking the time out to participate today and also to the attendees who've been here today. This session will all be transcribed and appear in the next edition of the Journal, which is coming out in mid-May, so we'll look for it there. And I hope that what we've heard from our experts today will prompt some of you out there to consider writing for the Journal on this or other related topics because this is a topic of very considerable importance to our future.

And the members of the Energy Bar can play a good, practical role with providing advice, both to the regulators, to the utilities that they represent, and to the public. So again, thanks so much to everybody. We look forward to you reading our next edition of the Journal and to any contributions that you might think about making. So again, thanks to everyone. Thanks to Sylvia for helping to organize this and to Michelle and Olivia from the Energy Bar Association for all their work in helping to organize today's program and we'll see you soon. Bye.

ELECTRIFY: AN OPTIMIST'S PLAYBOOK FOR OUR CLEAN ENERGY FUTURE

By Saul Griffith
Reviewed by Kenneth A. Barry[*]

An impassioned plea to retire and replace all existing equipment in the fossil fuel chain – from exploration and production to utilization – Saul Griffith's *Electrify: An Optimist's Playbook for our Clean Energy Future* (2021) (*Electrify*) is quite the opposite of Steven E. Koonin's *Unsettled* (2021). The two scientist-authors represent bookends in the debate over whether society must rapidly ramp down its dependence on hydrocarbons to meet its energy needs and mitigate the presence of greenhouse gases (GHG) in the atmosphere.

Griffith[1]– unlike Koonin – does not hesitate to prescribe concrete solutions; his book is full of them. Indeed, the author characterizes *Electrify* as an "action plan to fight for the future," as well as a technical roadmap to a clean-energy future.[2] In his opening salvo ("Preface," pp. xi – xiii), he invokes the language of war preparation to underscore both the scale and urgency of his recommendations:

"America needs nothing short of a concerted mobilization of technology, industry, labor, regulatory reform, and, critically, finance."[3]

To pull off the transformation, Griffith declares: "We need to triple the amount of electricity delivered in the United States[4] What is required is a moonshot engineering project to deliver a new energy grid with new rules – a grid that operates more like the internet."[5] However, consistent with his subtitle – "an optimist's playbook" – Griffith contends that if his remedies are adopted, energy will be cheaper and more plentiful in the long run, advising "The consequence of getting the technology, financing, and regulations right is that every family in the United States can save thousands of dollars each year."[6] He also envisions an avalanche of employment to help the country rebound from the "pandemic and economic crisis," citing a colleague's opinion that "as many as 25 million good-

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1. The book jacket describes Griffith as an "inventor, entrepreneur, and engineer," founder of Rewiring America (a nonprofit organization whose mission is to "decarbonize America by electrifying everything). In the text, he labels himself an "expert in energy systems." STEVEN KOONIN, ELECTRIFY: AN OPTIMIST'S PLAYBOOK FOR OUR CLEAN ENERGY FUTURE 2 (2021) ("*Electrify*").

2. *Id.* at xi, 2.

3. *Id.* at xi.

4. Griffith's book is aimed squarely at policies and practices in the United States, though he occasionally broadens his perspective.

5. *Electrify*, *supra* note 1, at xiii.

6. *Id.*

paying jobs" will flow from the conversion of all U.S. energy systems to "clean energy" solutions.[7]

Occasionally, Griffith's enthusiasm can bubble over into odd statements. For example, he muses in his Preface that "[with] our future in jeopardy. . . . Billionaires may dream of escaping to Mars, but the rest of us . . . we have to stay and fight." Readers may reflect that Mars's atmosphere is less hospitable than Earth's may be under even the worst-case scenarios painted by climate scientists.

Consistent with his call for radical and sweeping action, Griffith pounds the table for a halt to building or procuring "machines or technologies" that utilize fossil fuels. "There isn't time," he pleads, "for everyone to install one more natural gas furnace in their basement; there is no place for a new natural gas 'peaker' plant . . . .Whatever fossil fuel machinery you own, whether it is as a grid operator, a small business, or a home, that fossil machinery needs to be your last."[8]

I. THE "SCIENCE IS IN"; THE DANGERS ARE LOOMING

Griffith insists that "we can no longer debate the science," even if "for some people, science-based arguments will never be enough."[9] He evinces complete faith in climate models and their oftentimes frightening predictions:

"Scientists have written a large body of work on global warming and can predict the future climate from estimates of our current carbon emissions. We know, with certainty, that we are hurtling toward multiple environmental and human catastrophes."[10]

As a foretaste of impending disaster, Griffith provides a litany of specific, weather-related calamities the planet's inhabitants have endured in recent years – or will face more frequently in the future, he believes – *if* global average temperatures are allowed to increase beyond the red lines drawn by the U.N.'s Intergovernmental Panel on Climate Change (IPCC) (*i.e.,* 1.5 C. or, at worst, 2 C. above preindustrial levels).[11] Such calamities are directly traceable, in Griffith's view, to the build-up of excessive GHG emissions. The stark choice according to *Electrify* is this: either nations can continue down the perilous path they're now on, or – through bold, visionary action – not only avert a proliferation of environmental crises but also kick a virtuous economic cycle into gear:

> This is a chance to revitalize our cities, rejuvenate our suburbs, and reignite our small towns. We can rebuild a prosperous and inclusive middle class, as we enjoyed after World War II, with tens of millions of good new jobs . . . . If America does it right, everyone's energy costs will go down. Everyone has a role to play in the war effort.[12]

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7. *Id.* As an indication of how quickly things change in the economy, however, as of early 2022 (the date of this review), unemployment is back to the low single digits in the United States, and the biggest challenge is to find applicants to fill the numerous open jobs.

8. *Id.* at 2.

9. *Electrify*, *supra* note 1, at 11.

10. *Id.* The book at this point refers readers to a "primer on climate science" in appendix C.

11. *Id* at 12, 14.

12. *Id.* at 20. In the chapter that immediate follows ("Emergencies Are Opportunities for Lasting Change," pp. 21-28), Griffith offers a montage of moments in United States history where leadership has responded to challenges or crises with major programs, often entailing heavy financial lifts. The New Deal, the

Thus, at the heart of the book is an unabashedly populist message – often repeated – that making the necessary changes to ward off a climate crisis won't be a bitter pill, but rather a pathway to a healthier – and financially more solvent – society.

II. EFFICIENCIES APLENTY

Another pillar of Griffith's optimistic outlook is his anticipation of substantial efficiency gains attainable in a greener energy economy. However, this is not anything like the conservation-first, "make-do-with-less" efficiency preached from the 1970s on, when oil became a scarcer and dearer commodity in the aftermath of OPEC's market manipulations. Rather, Griffith prophesizes a "new narrative":

. . . a "story about what we stand to win – a cleaner electrified future with comfortable homes and zippy cars – which is better than nightmares about what we have to lose. We have a path to decarbonization that will require changes, to be sure, but not deprivation."[13]

Griffith's rejection of efficiency as sacrifice is followed by extended examination of the ways fuels are currently produced and consumed – broken down by individual sectors of the economy (*e.g.*, industrial, commercial, and residential) and by application (*e.g.*, space heating or cooling, transportation, or manufacturing processes).[14] It turns out the author spent a good part of his career studying fuel characteristics and sector-based energy usage, and has a lot to say on the topic. A distinctive argument in *Electrify* is that developing a greener fuel mix should *not* focus on producing decarbonized liquid or gaseous fuels – that is, the kinds of fuels that could more easily replace fossil fuels in the existing infrastructure. Griffith predicates this advice on efficiency – specifically, his belief that the steps involved in producing, transporting, and converting such fuels to useful energy entail excessive losses at each phase. In sum, the author submits that "machines" that run on the combustion of liquid or gaseous fuels – whether petroleum-based or one of the greener alternatives – waste too much energy versus an across-the-board conversion to infrastructure running on electricity (preferably sourced from the wind or the sun).

Griffith employs charts (sometimes rather busy ones) to illustrate the energy flows and losses occurring in the value chain from extraction and refining to transportation and utilization. Notwithstanding the complex detail of this presentation, Griffith has an overarching point to drive home: that through much greater electrification coupled with decarbonized power generation, "we probably only need 42% of the primary energy we need today . . . ."[15] After offering that arresting data point, he retreats from being so "granular," acknowledging that a

mobilization for WW II, and the Space Race are a few examples of this tour of inflection points in 20th C. history.

13. *Electrify*, *supra* note 1, at 47.

14. See generally *id.* at 51–61 ("Electrify!" chapter).

15. *Id.* at 61.

country's aggregate energy demands fluctuate with advancements in technology, new inventions, and new pastimes.[16]

Taking these variables into account, it is simplest to say that Americans will only need half the energy they use today, if we electrify everything while improving our lives. What a win.[17]

In this unmistakably upbeat manner, *Electrify* reassures us that we won't have to downsize or turn down the thermostats in our homes; that our cars can be "sportier when they are electric"; that air quality will improve; that we won't have to switch to mass transport or "wear a Jimmy Carter sweater"; and that we won't even have to "ban flying."[18]

Growing the Grid

To achieve the wholesale benefits Griffith envisions that by electrifying the energy economy, he acknowledges that we'll need a lot more of the stuff – in fact, three times the current amount of power production.[19] So he devotes a chapter – "Where Will We Get All That Electricity?" – to pondering this sizeable question.

Since the energy of the future must be all decarbonized in Griffith's worldview, he looks for supply to the major renewables – wind, solar, hydroelectric – and "possibly" also some nuclear (penciling in the latter because not all regions have ample solar, wind, or hydro resources).[20] In areas near the ocean, he expects "offshore wind likely to be the big producer."[21] In a digression on whether nuclear energy arguably fits into the big picture, Griffith alludes to a fierce controversy among university professors over whether "solar, wind, and water" can, on their own, provide the required capacity and reliability. When a Stanford professor, Mark Jacobson, contended that these renewable resources were indeed equal to the task, it produced "pushback to this proposal that was vicious . . . even by academia's petty standards . . . ."[22] The author implies that Jacobson may be "too anti-nuclear," but then hints that achieving reliability from renewables alone may be "easier than we think," ultimately deferring to a later chapter for more on the question.[23]

Returning to his vision of the future's generation mix, Griffith observes that the "heavy lifting" will be done by solar and wind; that the "majority" of renewable energy will come from these two resources *plus* geothermal and hydro (supplemented by "moderate nuclear and some biofuels as a backstop"), and – finally – that the "exact balance" will be shaped by regional considerations, market forces, and public opinion.[24]

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16. *Id.*
17. *Id.*
18. *Electrify*, *supra* note 1, at 61. For the airplane application, Griffith clarifies that biofuels, rather than batteries, will be a sustainable replacement.
19. *Id.* at 63.
20. *Id.* at 65.
21. *Id.*
22. *Electrify*, *supra* note 1, at 65.
23. *Id.*
24. *Id.* at 66.

In any event, *Electrify* foresees "solar panels and windmills" becoming ubiquitous. An all-solar grid, Griffith notes, would require occupying about 1% of the land mass – an amount equivalent to the space taken up by roads.[25] Rooftops, parking lots, and commercial and industrial buildings would do "double duty" as solar panel collectors, while lands currently used to farm crops would also host wind farms. In round numbers, Griffith estimates that the United States would need to generate 1500-1800 gigawatts (GW) to serve his all-electric society, which would require 15 million acres of panels in an all-solar scenario, or 100 million acres of wind farms (in an all-wind-energy construct).[26] If these numbers seem overwhelming, Griffith reminds us that the playing field – the entire U.S. land mass – contains 2.4 billion acres.[27]

Delving further into exactly where all these solar panels might go, for starters Griffith sets up – and knocks down – two straw men. His first extreme hypothesis is a central station in the Arizona desert that would power "all of America"; the other, which he says is favored by some environmentalists, is an all-distributed model (*i.e.,* limited to the rooftops of occupied buildings). But the former doesn't work, Griffith maintains, because the transmission and distribution would be prohibitively costly; and the other – a fully distributed model – would be untenable because there simply isn't enough residential or small business roof space to go around; industrial and commercial installations, *inter alia,* will also be needed. His conclusion, unsurprisingly, is that system expansion will require an all-of-the-above approach: some centralized installations (presumably *not* in remote deserts), along with exploiting "all the distributed energy we can harness."[28] Highway medians and parking lots are also fair game, in Griffith's spectrum of possibilities.[29]

Similarly, Griffith takes stock of lands that can play host to wind farms – emphasizing active and idle cropland, along with pasturage tracts – and finds these more than sufficient.[30] As to the possibility that "not in my backyard" attitudes could resist the prospect of windmills dotting the landscape, he offers this series of retorts: (1) fossil fuels "are pervasive and pollute everyone's back yard"; (2) society has "learned to live with a lot of changes" to the landscape; (3) we'll have in return "cheaper energy" and cleaner air; and (4) "we will have to balance land use with energy needs."[31] Whether these arguments will resonate in rural America – especially in hydrocarbon-producing states – or persuade conservationists who may prefer not to see windmill panoramas wherever they turn

25. *Id.*

26. *Electrify*, *supra* note 1, at 66.

27. *Id.* To help us visualize the relative land space required, Griffith includes a page with various-sized squares indicating how much land, proportionately, is devoted to croplands, forests, pasture, rural parks, cities, roadways, *etc.* *Id.* at 67.

28. *Id.* at 68. It may be that some homeowners don't want to see solar panels adorning their own roofs or those of their neighbors; but aesthetic consideration isn't addressed. Further, inasmuch as distribution systems are already installed where people live, it is not clear that a relatively more centralized approach to siting solar collectors would cost too much on the transmission and distribution side.

29. *Id.*

30. *Electrify*, *supra* note 1, at 69.

31. *Id.* at 69–70.

– remains to be seen. On the other hand, some farmers and ranchers may be eager for any incremental income from wind power installations. It could make for quite a policy tussle down the road.

In a longer discussion on the long-term viability of nuclear energy – a mature, low-carbon technology now in place – Griffith observes that the total cost has proven far greater than once anticipated ("likely more expensive than renewables") even though he concedes operating costs are low and output is reliable.[32] He also takes on the traditional paradigm of system planners who hold that some "baseload" energy is essential, claiming this is now debated by experts. In support of the premise that baseload supply won't be necessary in the future, he cites the "inherent storage capacity of EVs," the "shiftable thermal loads" in homes, businesses, and industrial plants, and the "potential capacity of back-up biofuels and various batteries."[33] His conclusion is that "we likely need less baseload power than people think and perhaps none at all."

Doubling down on this theme, Griffith points out that Japan and Germany both closed their nuclear units, while China is "slowing down on nuclear technology."[34] However, *Electrify* could have provided a fuller context in this regard. Japan's closure and safety review of all nuclear units following the 2011 Fukushima disaster, while comprehensive, was provisional: although many nuclear units were ultimately decommissioned, nine reactors at five locations had returned to commercial operation by March 2021.[35] Moreover, a government agency has observed that Japan will need to activate more nuclear capacity to displace its gas and coal-fired generation, if it is to achieve its goals under the Paris climate accord.[36] Germany, for its part, has encountered a range of reliability and economic challenges by following through with its controversial decision to dismantle its nuclear capacity, while resorting to more fossil fuel-burning capacity to supplement its large fleet of renewables. Finally, it would seem to bear mention that France and other European countries have not retrenched on nuclear generation.

Skeptic though he is, Griffith refrains from predicting the end of nuclear power. He predicts that (1) for "reasons of national security," the United States won't eliminate nuclear power; and (2) beyond U.S. borders, very densely populated nations – or those with a "lack of renewable resources" – will either have to avail themselves of nuclear or access renewable energy through imports.[37] He

32. *Id.*

33. *Id.*

34. *Electrify*, *supra* note 1, at 71. To say China is "slowing down" would appear to be a stretch. A quick survey of online literature readily yields the information that China is emphasizing nuclear construction as a mean to diversify away from its current heavy reliance on fossil fuels, and has indicated its plans to build scores of new reactors as part of its commitment at the global climate change conference in Glasgow in 2021. *See* Wikipedia, *Nuclear power in China,* https:// en.wikipedia.org/wiki/Nuclear_power_in_China (as of Apr. 4, 2022, 15:15 GMT).

35. *See Japan's Nuclear Power Plants in 2021*, NIPPON (March 31 2021), https://www.nippon.com/en/japan-data/h00967//.

36. *See* Wikipedia, *Nuclear power in Japan*, en.wikipedia.org/wiki/Nuclear_power_in_Japan (as of Apr. 4, 2022, 15:15 GMT).

37. *Electrify, supra* note 1, at 71.

also keeps the door open a crack to decarbonizing technologies he doesn't think can stand on their own two feet at present. Perhaps liquified renewables or carbon sequestration, he allows, will eventually prove their worth, but starkly adds: "it's too late and too dangerous to rely on miracles."[38] Griffith closes the chapter with a gust of green-populist rhetoric, first lambasting those who contend, with "cynical and specious arguments" and "massive misinformation," that renewables can't "do it all," and then upbraiding "the state-sponsored utility monopoly which gives low interest rates to big projects instead of consumers who need to swap their gas heaters for solar and heat pump."[39]

III. Reliability Round the Clock

Given Griffith's dismissal of the idea that renewables can't do for the grid what baseload energy does, it's hardly surprising that he dedicates a chapter[40] to imagining reliability in a renewables-heavy environment. He begins by blasting "people who resist decarbonization" on grounds of reliability as "dinosaurs" who "often have vested interests."[41] Continuing in this mode, he touches on the "grand bargain" of the 20th century that gave utilities a monopoly in exchange for the understanding that service would be both continuous and affordable to the "under-served."[42] This "deal worked pretty well," he concedes, during the last century but accuses both "corporate utilities" and rural co-ops of having "a mixed bag of incentives" that prevent them from rapidly decarbonizing to address climate change.[43]

Griffith's focus then turns to a set of concepts he says will enable the grid to meet demand continuously despite relying to a much greater extent on "intermittent" resources. The keys lie in both ramping up, by a factor of "three to four times," the quantity of power generated and reimagining the grid: "[w]e won't do this by tuning up the old grid; it will require rebuilding the grid with new twenty-first century rules and internet-like technology."[44]

Griffith first describes the inherent lumpiness of residential loads, and acknowledges they will get even lumpier if, as he recommends, all forms of home energy consumption (plus transportation) are converted to electricity. He paints a picture of heavier demand in the morning, almost "no electricity" demand at 3 p.m., and a big surge in demand (including EV recharging) when the family returns home in the evening.[45] Finally, on the supply side, he sketches the natural daily and seasonal variabilities of wind and solar energy production before asking how all these load and supply swings can be matched up.

38. *Id.* at 72.

39. *Id*.

40. *Id.* at 75–95.

41. *Electrify, supra* note 1, at 76.

42. *Id.*

43. *Id.*

44. *Id.* at 77.

45. *Electrify, supra* note 1, at 78. Here, *Electrify* doesn't take account of the new stay-at-home patterns wrought by the pandemic for office workers; nor does such a simplified diurnal cycle seem to recognize that home heating or air-conditioning loads remain active in the afternoon, depending on the time of year, in most climates – though Griffith almost simultaneously acknowledges "thermal [electric] loads are big and heavy."

The solution, according to Griffith, lies in creating "lots of storage" for renewable energy.[46] This is nothing new for the energy industry writ large, he points out, noting the substantial amounts of storage for natural gas and oil in the United States as well as the coal piles beside coal-fired generation plants.[47] Chemical battery storage, while "quite expensive," he admits, is falling in cost rapidly, and "large-scale deployment . . . is becoming a realistic possibility."[48] But the hitch, he proceeds to relate, is that batteries are suited to "ironing out" hourly or diurnal variations, not acting as longer-term storage reservoirs, as they are too costly; still, he foresees a time in the not-too-distant future when domestic battery storage coupled with rooftop solar will beat the current cost of utility-grid electricity.[49]

The chapter goes on to survey other types of energy storage – battery or otherwise. The former is represented mainly by EVs serving as supplemental batteries to feed the grid (Griffith envisions hundreds of millions of EVs doing this, providing a major new supply source, once the U.S. transportation fleet is converted to electric). Other types are "thermal storage," pumped hydro storage, and an assortment of other technologies Griffith does not regard as ready for prime time.[50] Finally, the author raises biofuels – from wood to agriculture waste to sewage – as surrogates for batteries to "bridge seasonal gaps . . . ."[51]

Returning to demand management, Griffith also suggests running big factory loads in the daytime to take advantage of the new abundance of solar energy, observing: "We reacted to cheap power at night by creating night shifts in heavy industry so that industry could consume that power," but in a "solar- and wind-powered world, we will have the opportunity to rethink some of these decisions."[52] However, readers might pause on the notion that night shifts were created to take advantage of cheaper power. While it is a bonus in places where time-of-day rates are in effect (or special contracts were negotiated), heavy, capital-intensive industries with 24-hour shifts and continuous production are mainly set up that way to reduce unit costs by averaging fixed costs over as many units as possible. In addition, some major industrial processes lend themselves to continuous operation rather than cycling up and down.[53] Also, Griffith probably overstates the flexibility of manufacturers to shift production schedules around to better synch up with the ebbs and flows of intermittent generation when he asserts: "Manufacturers can still produce the same amount of goods in the long-

46. *Id.* at 83.

47. *Id.*

48. *Id.*

49. *Electrify, supra* note 1, at 84.

50. *Id.* at 84–85. It is less than clear in this chapter how thermal storage works as electricity storage, unless Griffith is merely talking about incentives for demand interruption and load shifting. A few pages later, the author discusses "demand response" as a methodology for managing load and supply mismatches.

51. *Id.* at 86.

52. *Id.* at 87.

53. This reviewer is familiar with the aluminum industry, for example, which is designed for continuous production. The industry negotiates for lower-cost power associated with round-the-clock service and can withstand some temporary interruptions, but not for many hours at a time. A cloudy day resulting in an extended shortage of solar energy could be a disaster for an aluminum smelter.

term, but they can match their major loads to the available energy supply over time."[54]

To bring off such a future grid predicated on all (or largely) intermittent renewables, Griffith, as might be expected, also calls for constructing a great deal more transmission infrastructure – most critically, to take advantage of interregional wind and solar diversities.[55] He further advocates – as a self-styled "radical" idea – going overboard in the amount of solar and wind capacity to be developed, with a view to satisfying even winter peaks (when a renewables-only system is strained for capacity as solar availability wanes, just as heating and lighting demands increase). Griffith offers two rationales to buttress his "radical" proposal: first, that the incremental cost of building extra wind and solar to meet the winter peak would be cheaper than the alternative of constructing sufficient battery storage;[56] and second, that the resulting summertime solar surplus could be put to good use "in the production of hydrogen or ammonia or even the scrubbing of carbon from the atmosphere" (*i.e.,* carbon sequestration) – strategies he's previously relegated to the impracticable or improbable.

IV. Home is Where the Infrastructure Is

Electrify has much to say about the cost and financing of top-to-bottom decarbonizing of households and driveways. From universal rooftop solar to electric furnaces and water heaters, Griffith envisions a massive replacement cycle along with, not coincidently, an employment boom and attendant prosperity in all corners of the economy. One of his fundamental precepts is that our understanding of "infrastructure" must be expanded to encompass these new, all-electric home devices, battery storage and EVs included.[57]

Labeling such home equipment as "infrastructure" is Griffith's steppingstone to urging adoption of expansive new public policies to finance their purchase. Federal loan guarantees and subsidies to homeowners (and to landlords, where homes are not individually owned) are critical catalysts in making the replacement cycle affordable. Throughout the book, Griffith likens the decarbonization of the economy to a war effort, so recharacterizing energy devices in homes as semi-public infrastructure enhances the theme: *i.e.,* it is the duty of government in public emergencies to drive mobilization and lead change.[58] With his typically cheery air, he writes:

"[r]edefining infrastructure allows us to contemplate the intriguing notion that the United States might be just an interest rate away from a climate cure. . . . [L]owest-cost infrastructure-grade financing is crucial."[59]

54. *Electrify, supra* note 1, at 87.

55. *Id.* at 90–91.

56. *Id.* at 93. Notably, Griffith uses a hypothetical production cost for wind/solar of just 2-4 cents per kwh – which seems on the low end even for utility-scale solar, and does not account for incremental transmission investment costs.

57. *Id.* at 98–101.

58. Later in the book Griffith includes an entire chapter – "Mobilizing for World War Zero" – to embellish the point, lest it's been lost on readers thus far. *Electrify, supra* note 1, at 163–72.

59. *Id.* at 101.

In the ensuing chapter (Chap. 10, "Too Cheap to Meter"), Griffith goes into detail to make his pitch that, with today's technology, utility-scale solar and wind generation already outcompete natural gas and coal power from a cost perspective.[60] But Griffith's ultimate quest is to convince readers that *virtually every roof in America* should be fitted with solar panels, to attain even greater savings than utility-scale renewables can offer. His vision is encapsulated in this excerpt:

> Here is the transformative point about rooftop solar: because there are no transmission and distribution costs, it can be phenomenally cheap. Even if the cost of utility-scale generation were free, we don't know how to transmit it to you and sell it to you for less than the cost of rooftop solar. This doesn't mean the whole world will run on solar and distributed resources, but it does mean that if we are looking to make the lowest-cost energy system, an awful lot of America's energy will come from our rooftops and our communities.[61]

The chapter goes on to sketch how the costs of wind and solar generation have fallen precipitously in recent years, projecting that they will tumble even further, "likely halv[ing] the cost of renewables again – a nail in the coffin of fossil fuels."[62]

In his clincher chapter, "Bringing it all Home,"[63] Griffith rolls out an elaborate modeling effort to demonstrate how a big capital expenditure program with low-cost financing to equip homes for maximum renewable energy production and usage would, in the long run, "save us all money" versus the status quo.[64] The chapter is informative in depicting the full spectrum of household costs, where energy fits into the total budget, and the extent to which energy costs might be driven down by full adoption of the book's recommendations.[65] Griffith's rollup of the data projects that rooftop solar ought to cover about 75% of total home energy needs; and, figuring a long-term cost of 5 cents/kWh for this home-generated energy (based on financing costs of 2.9%) while assuming a national average cost of 14 cents per kWh for utility-delivered electricity, Griffith emerges with an estimated annual savings per household of *at least* $1000 and "if we do very well," $2500.[66]

60. *Id* at 104ff. Generation cost comparisons are always a complicated subject, and highly dependent on assumptions. An immediate observation is that the comparison in the subject chapter uses "levelized cost of energy" for wind, solar, and fossil-fuel capacity. But a great deal of natural gas and coal-fired capacity is already built and in service; hence, their variable operating cost is relevant to a comparison as well.

61. *Id* at 105.

62. *Electrify, supra* note 1, at 71, at 109. Griffith neglects to mention that much of the reductions in solar costs have come from China's takeover of the industry. *See,* DANIEL YERGIN, THE NEW MAP 396-97 (2020) 96–97 (reporting that almost 70% of solar panels are made in China; over 80% by Chinese companies within or outside China, and that almost 95% of the solar wafers that are the heart of panels are produced there). Yergin notes that "the cost of solar panels came down by an extraordinary 85% between 2010 and 2019, driven mainly by Chinese manufacturing and massive capacity and by technical improvements" as well as by what a renewables advocacy organization has labeled "cutthroat pricing" thanks to China's overcapacity. *Id* at 397–98.

63. *Electrify, supra* note 1, at 112–29 (Chapter 10).

64. *Id.* at 112.

65. The chapter even contains a chart depicting state-by-state household use of energy, broken down by fuel source. *Id.* at 116.

66. *Id.* at 121–22.

Necessarily, any such modeling is chock-full of assumptions. Griffith allows that his assumptions are "aggressive," but "not without precedent."[67] What may leave readers scratching their heads is what happens to the transmission and distribution costs the book recognized are big ticket items in the cost of delivered energy, not to mention the fixed costs of maintaining central stations at the ready. Griffith apparently leaves these costs off the books when it comes to figuring out the purportedly massive end-user savings.[68] But distributed energy owners still depend on the grid for backup – *i.e.,* nocturnal or cloudy-day energy – unless they're prepared to decouple and rely on their EV batteries (or fossil-fuel home generators) to carry them through sunless hours. But even Griffith does not go that far.

Griffith's argument for major government involvement in financing the electrification of homes and cars also draws on "climate justice" considerations. He fairly points out that the wealthy can best afford the "upfront capital costs" of rooftop solar, EVs, and other decarbonizing gadgets because "they have access to easy credit and home equity loans."[69] Indeed, some well-heeled Americans can afford to pay for their luxury EVs out of savings and cashflow. Yet, as the author points out, the low-income segment of the population would benefit the most from any cost savings attributable to electrification. And obviously, a mass conversion to all-electric domestic and transportation systems requires a "no household left behind" approach. Hence, Griffith seizes the moment of "historically low interest rates," coincident with the 2020-21 pandemic, to "finance the household technology and infrastructure that will decarbonize our future lifestyles."[70]

V. COMPENSATING THE LEGACY ENERGY COMPANIES

Perhaps surprisingly, given Griffith's frequent expressions of scorn for the "fossil fuel industry," *Electrify* proposes a compensation package for the "stranded assets" of legacy hydrocarbon companies. To do otherwise, he posits, would invite the kind of financial calamity the United States (and much of the developed world) experienced during the mortgage market crisis and stock market crash of 2008. "Clearly," he states, "we can't just pull the rug out from underneath the industry that gave us modernity. We need a plan."[71]

The author tosses out some assumptions about the profit margins for proven reserves (figures that are not necessarily compensatory, given the dramatic rise in oil and gas prices since mid-2021), and comes up with a multi-trillion-dollar buyout hypothesis. The section is far from fleshed out; it is more like a gesture –

67. *Electrify, supra* note 1, at 121–22.

68. In addition to the "transformative point" quote above (*Id.* at 105), Griffith stresses (*Id.* at 104) that even the "impressively low" costs of utility-scale solar can be beaten with home generation: "Oddly, though, rooftop solar can be even cheaper because if you're generating electricity yourself, you don't have to pay for distribution." *Id.*

69. *Id.* at 125.

70. *Id.* at 129. Readers in 2022 will note, however, that the near-zero interest rates Griffith invokes are transitioning towards higher rates as inflation become a prevailing concern.

71. *Electrify, supra* note 1, at 133.

an opening bid in an imaginary negotiation – and it's not clear either who exactly would *pay* the trillions or whether international and state-owned energy companies (*e.g.,* Russian, Saudi, and Venezuelan companies) would *receive* payouts, or whether the rescue package would be limited to Western democracy companies.

It's also less than clear regarding the time frame in which the fossil fuel companies would be bought out. Elsewhere, *Electrify* implies what amounts to a gradual phase-out, with those new, "clean energy" machines being purchased when the older ones reach the end of their useful lives.[72] That could take decades. Yet, in the chapter on industry compensation, while applauding the spirit behind "divestment" campaigns to "slowly starve the fossil fuel industry of the precious capital they need," the author argues that the strategy is too slow to be effective in light of "the urgency and inevitability of climate change . . . ."[73]

In a chapter of particular interest to the regulatory community ("Rewrite the Rules!"),[74] Griffith surveys the diverse field of federal and local laws and regulations and declares them largely unsuited to expediting the transition to a clean energy world. The chapter touches on numerous aspects, from construction codes to ratemaking, and notably takes aim at "net metering" – generally thought of as a boon to home solar generators – as *not* "good enough," because customers offering up excess energy to the grid are only offered the wholesale, not the retail, value of their kWh. Likewise, time-of-use pricing "isn't good enough either" in Griffith's judgment because "not everyone has that choice" of when to consume.[75]

Instead, Griffith advocates a construct he calls "grid neutrality," which he evidently sees as democratizing the power system, much like the internet has done for information and trade.[76] Under this scheme, households, like utilities, could buy and sell energy to each other. The public utilities, he admits, "don't love this idea, especially those that are also trying to protect their natural gas business," but such patent self-interest should not, in Griffith's view, intimidate the public from imposing more forward thinking:

"But remember that 'we the people' regulate the utilities, so we don't need to fear them. We can control them; we just need to express our collective will."[77]

VI. CONCLUSION

Griffith is not the most objective of guides. In a field generally calling for empiricism, balance, conservative assumptions, and sober judgments, he frequently comes off as a cheerleader and prophet for a movement he regards as lit-

72. *See e.g.* where Griffith argues that the government's payout for the cost for the transition would "only amount to about $300 billion per year for the 15 years of mobilization." *Id.* at 154, or where Griffith suggests the large sticker price for the Green New Deal should be put in perspective: " . . . this amount will be spread out over 15-20 years. This is mostly spending the country was going to do anyway – everyone is going to buy a new car or two in that 20 years, and appliances, and home retrofits . . . ." *Id* at 153.

73. *Id.* at 133–34.

74. *Id.* at 137–44.

75. *Electrify, supra* note 1, at 142.

76. *Id.* at 143–44.

77. *Id.* at 143.

erally world-saving. The earnestness and passion he brings to the task seem genuine. And it helps that, even as *Electrify* burrows into the technical and policy-wonkish depths of its material, Griffith's writing style is commendably clear and easy-going – frequently jokey and sometimes even profane – as he strives to lighten the mood and forge a camaraderie with his readership.

Occasionally, Griffith simply gets things wrong. He inexplicably refers to the "2016 [sic] Paris Agreement to avert climate crisis."[78] In his chapter about preparing for "war," he tells us that in 1939, the "mood of the country, particularly among the New Deal Democrats, was against intervening in international affairs." While the sentiment against getting involved in Europe in the late 1930s had both left- and right-wing adherents, President Roosevelt – the leader of the New Deal – sought *more* involvement, as he navigated the political headwinds against actively assisting the Allies.[79] Griffith's chapter kindling enthusiasm for an explosion of government expenditures to address unemployment and lift the country out of a recession[80] seems almost quaint in early 2022, as unemployment is low, good jobs go begging, and inflation (partly from government stimuli) is a real concern. In an appendix,[81] Griffith takes hard sideswipes at carbon sequestration and use (even as an adjunct to burning carboniferous fuels) as well as denouncing fracking and natural gas – all 21st century energy mainstays (or in the case of carbon sequestration, a promising frontier technology).[82]

Two major caveats should be kept in mind. First, Griffith is a scientist and engineer, but not a climate scientist, and does not attempt to reexamine the mainstream consensus on GHG. Rather, he wholeheartedly embraces its most dire predictions, using them as a springboard for challenging the incumbent energy industry to accept a raft of changes. Second, Griffith's analysis and prescriptions for reform are targeted expressly for the United States. Although climate change is obviously a worldwide issue, the rest of the globe only comes in for only glancing attention; his premise is that if the United States cleans up its act, the rest of the world will follow. Whether that premise holds water is a question readers can contemplate for themselves.

For those already inclined to accept that climate change is mankind's most forbidding challenge, the author's absolutism and devotion to radical action will prove stimulating. His remedial strategies, tinged with a sunny optimism, will equip persuaded readers to enter the fray with specific concepts, along with armloads statistics and graphs. On the other hand, energy pragmatists and climate

78. *Id.* at 14. The agreement was struck in December 2015.

79. Conversely, Senator Robert Taft, a prominent Republican leader, ardently opposed any United States involvement in the conflict in Europe, up until the bombing of Pearl Harbor in December 1941, though Taft's isolationism drew cross-fire from liberal Republicans. *See generally* SARAH CHURCHWELL, BEHOLD, AMERICA (2018), for an account of United States support for, or tolerance of, Fascist regimes in Europe in that era.

80. *Electrify, supra* note 1 at 145–61 (Chapter 15: "Jobs, Jobs, Jobs").

81. *Id.* at 193–94.

82. See Yergin, *supra* note 62, at 405 ("The 2015 Paris climate compact provided new impetus to develop 'carbon capture and storage,' or CCS. Around the same time, a "U" for "use" was added to the acronym . . . .CCUS takes many forms today. For instance, captured carbon is being used to manufacture products like cement and steel. 'Direct air capture' – pulling CO2 out of the air – had seemed fanciful, but progress is being made and units are being scaled up.").

change skeptics should find the volume of use as a compendium of positions green energy advocates will stake out in public forums, so they might as well get more familiar with them.

UNSETTLED: WHAT CLIMATE SCIENCE TELLS US WHAT IT DOESN'T AND WHY IT MATTERS

By Steven Koonin
Reviewed by Kenneth A. Barry[*]

The key messages of Dr. Steven E. Koonin's new book, *Unsettled,*[1] on the current state of climate science and its implications for energy policy, though cogently organized and expressed, are nonetheless disorienting. Rather than offering the consensus warnings of a collapsing climate and impending natural disasters, Koonin comes from the opposite direction.[2] He argues, with considerable passion, that much of what you have heard about the gravity and certainty of the science underlying the parade of doomsday predictions (absent a swift transition away from fossil fuels) is overwrought at best and deceptive at worst. Asking us to rethink the well-documented foundations and Cassandra prophesies of climate science is, well, unsettling.

Koonin cannot be dismissed as an anti-science kook or front man for the oil and gas industry. He boasts a long and distinguished resume, spanning the academic world, government service, and private industry. A longtime professor of theoretical physics and senior administrator at Caltech, he currently teaches at New York University. In between, he has had stints as BP's chief scientist in charge of researching alternative and renewable fuels and – perhaps most notably – with the Obama Administration as Undersecretary for Science within the U.S. Department of Energy.[3] Though not strictly a climate scientist, his career has taken him deep into the fields of energy use, weather phenomena, and the climate – leading him to express counter-consensus views in *Wall Street Journal* op-eds beginning in 2014.[4]

As can be readily imagined, the pushback from the climate science establishment to Koonin's book-length *cri de coeur* has been considerable.[5] Moreover, the publication of *Unsettled* narrowly preceded the latest U.N. International Panel on Climate Change (IPCC) report, issued in August 2021, so the volume aims its fire at an older (2013) IPCC report of comparable scale and scope

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1. STEVEN KOONIN, UNSETTLED: WHAT CLIMATE SCIENCE TELLS US, WHAT IT DOESN'T, AND WHY IT MATTERS (2021).

2. Also appearing in this edition of the *Energy Law Journal* is a review of a second book – *Electrify,* by Saul Griffith – that, conversely, insists climate change is a well-understood but dire threat, calling for a pervasive overhaul of the U.S. energy infrastructure to largely eliminate its greenhouse gas emissions.

3. For a more complete account of Dr. Koonin's professional career and credentials, *see* KOONIN, *supra* note 1, at 305-06.

4. Steven Koonin, *Climate Science is Not Settled*, WALL STREET JOURNAL (Sept. 19, 2014), https://www.wsj.com/articles/climate-science-is-not-settled-1411143565.

5. *See, e.g.,* Marianna Lavelle, *A New Book Feeds Climate Doubters, but Scientists Say the Conclusions are Misleading and Out of Date*, INSIDE CLIMATE NEWS (May 4, 2021), https://insideclimatenews.org/news/04052021/a-new-book-feeds-climate-doubters-but-scientists-say-the-conclusions-are-misleading-and-out-of-date/.

(among other official studies). The 2021 IPCC report raised louder alarm bells than ever, and only Koonin can defend the durability of his critique in light of the more recent findings. However, the focus of this review is on the core contentions of *Unsettled,* not the inevitable jousting between the author and his adversaries in the climate science and advocacy communities.

I. CENTRAL CONCERNS OF *UNSETTLED*

It should be emphasized at the outset that Koonin embraces certain concepts at the heart of the climate consensus. He acknowledges that carbon dioxide emissions from human activities (especially from fossil fuel burning) are on the increase; that they remain in the atmosphere for an exceptionally long time; and that, in combination with other greenhouse gases (GHG), they are contributing to the ongoing warming of the planet. In these respects, he separates himself from so-called climate change "deniers." His principal issues have to do with the *extent* to which human activities (versus natural cycles) are driving the warming; how the complexities of the climate may respond over time to "human influences"; whether recent incidences of extreme weather can be attributed to the build-up of atmospheric carbon dioxide in recent decades; whether serious adverse economic impacts are likely to result from the temperature increases foreseen by the IPCC and in similar reports; how much confidence can be placed on the climate models that ominous predictions rely upon; and, above all, whether it is realistic to expect that governments around the world will, anytime soon, mandate radical transformation of the systems and activities that generate GHG. In all these matters, Koonin casts a critical look at the reigning consensus and attempts to undermine it with a wealth of examples and graphs.

Where Koonin comes out is that:

- There is far too much uncertainty in the projections of global warming and attendant doom on which to base massive societal changes and investments in alternative systems;
- In any event, the transformative actions proposed have not been happening at anywhere near the pace sought by the 2015 Paris climate accords to achieve its ambitious milestones; and
- The world would be best served by researching geoengineered climate remedies and "adaptation" solutions if the feared outcomes of inaction do eventuate.

Koonin supports the development and deployment of cost-effective, lower-carbon technologies, but questions how far, realistically, they can get you down the path of stabilizing the seemingly inexorable increase of atmospheric carbon dioxide.

II. CLIMATE CHANGE'S GRIP ON THE PUBLIC CONSCIOUSNESS

Koonin covers a lot of ground in this 300-page assessment of climate change science and its collision with the world's (especially developing nations') increasing appetite for energy as part of the quest for a higher standard of living. The book's early chapters provide a concise primer on the elements that drive climate and the complex interactions between them (stressing how the oceans and vegetation-covered land masses, the atmosphere protecting us from space, and the sun all interchange heat and energy). On these natural cycles, he superimposes the impacts of human intervention, most importantly GHG emissions from burning carbon fuels, from industrial processes, and from agriculture. The clarity of this basic science overview makes the book worthwhile for lay readers, even if they disagree with Koonin's doubts about the imminence of the "climate crisis."

The meaty middle chapters of *Unsettled* set forth the author's efforts to deconstruct the alarming conclusions of previous IPCC reports along with the parallel reports issued by the U.S. government – *i.e.,* the quadrennial National Climate Assessment (NCA).[6]

However important these sections may be to buttressing Koonin's argument, the introductory and concluding chapters of *Unsettled* capture best what animates the author. In the opening pages, he distills the essence of what he somewhat derisively terms "The Science":

> "*Humans have already broken the earth's climate. Temperatures are rising, sea level is surging, ice is disappearing, heat waves, storms, droughts, floods, and wildfires are an ever-worsening scourge on the world. Greenhouse gases are causing all of this. And unless they're eliminated promptly by radical changes to society and its energy systems, 'The Science' says Earth is doomed*" [emphasis in original].[7]

Having laid out these hyperbolic (in his view) claims, Koonin seeks to deflate them by asserting the data shows: (1) heat waves in the U.S. are no more common than in 1900; (2) the "warmest temperatures" have not risen in the U.S. in the past 50 years; (3) humans have had no detectable impact on hurricanes; (4) the ice sheet in Greenland isn't shrinking any more rapidly now than 80 years ago; and (5) the "net economic impact of human-induced climate change" is expected to be "minimal."[8] The book posits, in short, that there is a vast gap between the public's understanding of the impacts of climate change versus the actual data. Even worse, he believes, is that *policymakers* are being misled, as they get their information only after it has been "put through several different wringers."[9]

Unsettled is as much a subjective account of one scientist's journey through the maze of climate science as it is a skeptic's interrogation of the consensus. Koonin tells us how his career in 2004 began to concentrate on "the subject of climate and its implications for energy technologies," first as an inhouse scientist with BP and then in his tour of duty with the Obama Administration's Department of Energy. In these roles, reflects Koonin, "I found great satisfaction . . .

6. As mentioned above, the most recent IPCC report dissected by Koonin is *not* relatively recent, dating from 2013. However, the NCAs also challenged by Koonin are more recent, dating from 2018. Koonin explains that these latest U.S. government reports came out in two volumes – one released in late 2017 entitled the "Climate Science Special Report," or CSSR, focusing on "physical climate science"; and a second issued in late 2018, focusing on the "impacts and risks" of the changing climate, and how mankind might adapt. *S*ee KOONIN*, supra* note 1, at 21-22.

7. *Id.* at 1 (emphasis in original).

8. *Id.* at 1-2.

9. *Id.*

helping to define and catalyze actions that would reduce carbon dioxide emissions, the agreed-upon imperative that would 'save the planet.'"[10] But his "doubts" began in late 2013, when a professional society of physicists asked him to lead a team to "update its public statement" on climate science, leading him to convene a workshop to "stress test" the current state of climate science.[11] Koonin emerged from this process "shaken," he claims, by "the realization that climate science was far less mature than I had supposed."[12]

Central to the revision of his view were his "discoveries" that:

- Human influences exert a "growing but physically small" warming effect, but the "deficiencies" of climate data hinder scientists' ability to "untangle the responses to human influences from poorly understood natural changes";
- The results of climate models disagree with each other, and "sometimes" the modelers apply "expert judgment" to "adjust the model results and obfuscate shortcomings";
- The government and UN press releases and summaries "do not accurately reflect" the reports themselves;
- The science is "insufficient to make useful projections" about how the climate is likely to change over time and the effect of human actions upon it.[13]

It was following his enlightenment, Koonin relates, that he went public with a lengthy essay published in the *Wall Street Journal* denouncing a "comfort of certainty" surrounding climate science that is, in reality, a hindrance to "the scientific enterprise."[14] Many online comments in response were supportive, but many of his scientific colleagues were "outraged," suggesting he had "broken some code of silence" by highlighting the uncertainties.[15]

Six years on, notes the author, "climate alarmism" has come to dominate U.S. politics, especially in Democratic circles (in which he otherwise feels most comfortable), while in the 2020 Democratic primaries, candidates sought to outdo one another in issuing "over-the-top statements about the 'climate emergency.'"[16] The political discussions included the sweeping "Green New Deal" and culminated with the appointment of John Kerry as "climate envoy," whose mission was to spend "almost two trillion dollars to fight 'this existential threat to humanity'" – all of which has left Koonin "increasingly dismayed."[17]

A bit later in the book, Koonin describes how the media amps up its climate change stories, with headlines often more alarming than the underlying content.

10. KOONIN, *supra* note 1, at 3.

11. *Id.*

12. *Id.* at 4.

13. *Id.*,

14. KOONIN, *supra* note 1, at 4-5.

15. *Id.* at 4. Koonin recounts that the chair of a "respected university earth sciences department" informed him privately that he agreed with pretty much everything Koonin wrote but that he didn't "dare say that in public."

16. *Id.* at 5.

17. *Id.*

Scientists, the media, and politicians all come in for their share of blame for the distortions Koonin finds are rife in the public's understanding of climate science. In the last paragraph of his "Apocalypses that Ain't" chapter, he lowers the boom on the lot of them:

> It's clear that media, politicians, and often the assessment reports themselves blatantly misrepresent what the science says about climate and catastrophes. Those failures indict the scientists who write and too-casually review the reports, the reporters who uncritically repeat them, the editors who fan the fires of alarm, and the experts whose public silence endorses the deception. The constant repetition of these and many other climate fallacies turns them into accepted 'truths.' [18]

III. UNMOORED MODELS

While multiple chapters of *Unsettled* undertake to dissect the apprehensions raised by climate science researchers, one of the most central is his challenge to the respect accorded climate models. The point is pivotal because so many of the studies hinge on model-based predictions of upsets in the earth's climate and ecosystems. Koonin wades into the subject with enthusiasm, advising he has a deep background in the development of computer modeling as a tool of science (noting he "wrote one of the first textbooks on the subject.")[19] To foreground the chapter, he quotes the celebrated remark of a University of Wisconsin statistician: "All models are wrong, but some are useful."[20]

Far from opposing the use of modeling – to the contrary, he calls them "central to climate science [to] help us understand how the climate system works"[21] – he nonetheless warns that "usefully describing the earth's climate remains one of the most challenging scientific simulation problems there is." Despite such caveats, the temptation to lean on modeling to project the future of the climate in the face of GHG emissions is almost Faustian. Koonin states:[22]

"It's easy to be seduced by the notion that we can just feed the present state of the atmosphere and oceans into a computer, make some assumptions about future human and natural influences, and so accurately predict the climate decades into the future. Unfortunately, that's just a fantasy . . . ."

Koonin proceeds to offer a highly granular description of how climate models are built from the ground up. That is complicated enough stuff, but he then layers on nuances and challenges so "excruciatingly difficult [that] anyone who says climate models are 'just physics' either doesn't understand them or is being deliberately misleading."[23] Koonin does his best to explain what the models can and can't take account of, the assumptions and "tunings" (*i.e.,* "necessary but

18. KOONIN*, supra* note 1, at 163. Prior to the conclusion quoted below, the chapter examines several examples of climate science calamity predictions – involving deaths from weather-related events, adverse impacts to the food supply, and direct overall damage to the U.S. economy – and concludes the data does not support the headline fears.

19. *Id.* at 78.

20. *Id.* at 77 (Attributing the remark to George Box).

21. *Id.* at 78.

22. KOONIN*, supra* note 1, at 79.

23. *Id.* at 81.

perilous" fudge factors), and the problems of estimating "feedback" loops.[24] These "tunings," he elaborates, are required to make models match "the far more numerous observed properties of the climate system"; but this perforce "casts doubt on whether the conclusions of the models can be trusted," while making it "clear we don't understand features of the climate to anywhere near the level of specificity required given the smallness of human influences."[25]

Koonin maintains that periodic state-of-the-science assessments such as IPCC and NCA provide an illusion of general agreement among models by averaging the results of an "ensemble" of models; but, unless you read "deep into the IPCC report," this practice masks the fact that the models "disagree wildly with each other."[26] He is also troubled by the models being unable to duplicate or explain why the climate experienced a "strong warming" trend from 1910-40.[27] Finally, he posits that the failure of the models to reflect warming in the early part of the twentieth century "suggests that it's possible, even likely, that internal variability – the natural ebbs and flows of the climate system – has contributed significantly to the warming of recent decades."[28]

With such a "lot to fret about in the climate modeling business," Koonin concludes, "No wonder we've got a poor understanding of how the climate will respond to rising GHG concentrations. The more we learn about the climate system, the more we realize how complicated it is."[29]

IV. The Impracticability of Decarbonizing the Economy

In several concluding chapters, Koonin swings back from the technical and granular to the macro. Here, his overriding question is whether it is realistic to suppose that societies will make the major changes, expenditures, and sacrifices necessary to achieve the IPCC's goal of "stabilizing" GHG emissions by mid-century and thereby imposing a ceiling on global temperature increases of either 2 or 1.5 degrees C.[30] In "The Chimera of Carbon Free" chapter,[31] he concludes that these emission goals, whether or not effective to halt warming, are simply unattainable.

He begins this discussion with the truism that energy systems evolve slowly over decades. The reasons, he elaborates, have to do with the complexity of the infrastructure, the long-lived investments in it, and society's need for reliability (leading to conservativism in making changes). In the U.S., the three most dom-

24. *Id.* at 84-85.

25. *Id.* at 85.

26. KOONIN, *supra* note 1, at 86. Indeed, he continues, the simulated global average surface temperatures vary by "about 3 degrees C, three times greater than the observed value of twentieth century warming they're purporting to describe and explain."

27. *Id.* at 88-89.

28. *Id.* at 90-91.

29. *Id.* at 95.

30. The global Paris conference of 2015 adopted a straddle of these two temperatures limitation goals, compared with a baseline of the pre-industrial age. The 1.5 degree ceiling is aspirational, while the 2 degree ceiling is viewed as the maximum tolerable increase.

31. KOONIN, *supra* note 1, at 211-224.

inant sources of GHG emissions are transportation, electricity, and industry.[32] Koonin notes that, while the U.S. has reduced emissions by 16% since their peak in 2005 – a not inconsiderable feat, largely propelled by the transition from coal to natural gas fueling electric generators – *global* emissions increased by one-third over the same period.[33] This fact alone illustrates the uphill nature of the challenge.

The chapter then surveys the obstacles and headwinds to any rapid decarbonization of the systems that produce, transport, and consume energy in the U.S. alone. The discussion is substantive and detailed, raising issues about technical feasibility (including reliability), political will, and economics that any advocate of urgency in replacing fossil fuels with "clean energy" substitutes must address and solve. Koonin agrees that "government has an important role to play" in sponsoring research, both basic and developmental, and does not dismiss the notion that cleaner and technically feasible technologies are out there; but he cautions that they "aren't ready for the marketplace."[34] Likewise, he submits:

" . . . creating an emissions-free energy system will be broadly disruptive – both economically and behaviorally. The question is whether the country will choose to invest the financial and political capital needed to bring that transformation about . . . .I think that's unlikely to happen anytime soon.[35]

Moreover, Koonin challenges the notion that a more urgent transition to low-carbon fuels in the U.S. would make much of a difference to the global climate, since it represents only 13% of worldwide GHG emissions. While some, he acknowledges, would argue that the U.S., by setting an example, would see the rest of the world follow suit, he wonders "how likely they are to do so when their energy needs are so pressing and the benefits of reductions so murky."[36]

V. "PLANS B" AND CONCLUSION

In his last two chapters ("Plans B" and "Final Thoughts"), Koonin advances options deemed almost unthinkable by many climate scientists and advocates. The first is that "geoengineering" merits research and practical studies. The underlying premise is that, even though the more worrisome scenarios depicted by "consensus" climate scientists aren't likely to play out, neither can they be ruled out. Under the rubric of geoengineering, Koonin sketches two possibilities: (1) for a relatively economical cost, it is possible to spread reflective particles (aerosols) in the atmosphere to cut down on the solar energy reaching the earth (imitating what happens for extended periods after volcanic eruptions); and (2) at a higher cost, equipment could be deployed to directly remove carbon dioxide

32. *Id.* at 226. Agriculture comes in a poor fourth, followed by commercial and residential.

33. *Id.* at 227.

34. *Id.* at 234. He cites advanced solar, fission, fusion, and next-generation biofuels as examples of technology worth "pursuing."

35. KOONIN, *supra* note 1, at 235 (citing the "barriers" he has already discussed and other, more pressing "demands on the nation's attention and resources" as the reasons for his skepticism).

36. *Id.*

from the atmosphere.[37] While neither of these options is technologically pie in the sky (so to speak), neither is a panacea, and hence Koonin delineates the obstacles – practical, economic, and political – associated with each.

Plan B-2 in Koonin's book is simply "adaptation," a resort which most environmentalists consider anathema. The author argues that human beings have proven adaptable to many types of climates; and, besides, this recourse represents what he believes "*will* be our primary response," not necessarily what *ought* to happen.[38] Moreover, to the extent that climate change is partially due to natural cycles (a thesis that holds more water in Koonan's judgment than that of his adversaries) , it may be unavoidable.[39] Either way, Koonin recommends more studies on adaptation that go beyond mere "identification" (the main way it has been addressed so far) and delve into "implementation issues" and "cost/benefit analysis" directed to different strategies. Further, he notes, since adaptation is more accessible for wealthier societies, the precursor to enabling adaptation is to focus in the shorter term on "alleviating poverty, which would be a good thing for many reasons having nothing to do with the climate."[40]

In his closing paragraphs, Koonin first asserts that the role of the scientist is to describe, not to prescribe, and that he's written his book accordingly.[41] But after this disclaimer, he shifts gears to recommend (as you would expect, given his critique) that climate science need "more sustained and improved observations of the climate system" and a better understanding of "the tremendously complex climate models we've built."[42] He adduces to this a plea for "more honest discussion" that "goes beyond slogans and polemics, and is free of accusations of skullduggery . . . .Let's further our understanding, rather than repeating orthodoxy."[43]

It should be concerning that any scientist who casts doubt on the more ominous conclusions of climate scientists is branded an apostate. On that ground if no other, Koonin has a valid point; science does, indeed, thrive on skepticism and hard testing of hypotheses. On the other hand, his critics have alleged that the technical concerns outlined in *Unsettled* have been superseded by data in latest IPCC report. One can only hope that the scrutiny of The Science continues, with both sides keeping an open mind to the wide range of possibilities. Whether Koonin's book is mostly a compendium of quibbles or a dead-on-target critique of the "climate emergency" warnings is an issue that needs to be sorted out, not just in the scientific journals but also in the public square.

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37. *Id.* at 237-48.
38. *Id.* at 245.
39. KOONIN, *supra* note 1, at 246.
40. *Id.* at 248.
41. *Id.* at 250.
42. *Id.* at 251.
43. KOONIN, *supra* note 1, at 251.

REGULATING PUBLIC UTILITY PERFORMANCE: THE LAW OF MARKET STRUCTURE, PRICING AND JURISDICTION

By: Scott Hempling
Reviewed by David P. Yaffe*

Everyone involved with utility regulation during the last ten years has been bedeviled by the difficulty in applying traditional (and indeed statutory) regulatory principles to the explosion of climate change, electric utility industry structure, digital divide, federal-state jurisdictional overlap and ideological issues affecting the electric and natural gas business and to a lesser extent telecommunications. Indeed, the Federal Energy Regulatory Commission's ("FERC's) recent spate of technical conferences about a multitude of electric utility issues, its pipeline certificate policy statement review and parallel actions by state commissions in those areas and telecommunications reflect the urgency of climate, environmental, social equity and privacy issues. The urgency felt by regulators and the regulated to address the effects of these and other trends in the electric, natural gas and telecommunications industries led Scott Hempling and the American Bar Association to issue a second and revised edition of his not-so-old 2013 book "Regulating Public Utility Performance."

Unlike most public utility texts that provide a deep dive into individual subjects, "Regulating Public Utility Performance" is written "to present the fundamentals of public utility law: the legal principles that practitioners need to make public-spirited proposals and that policymakers need to make public-spirited decisions."[1] Indeed, Mr. Hempling's ambition in this book is to promote the "effectiveness of regulation" in a "public spirited" direction. This goal of "increasing" effectiveness rather than just teaching the basics distinguishes this text from other legal case books or economic texts on principles of public utility regulation. Instead of elucidating principles of regulation to educate lawyers, economists and engineers how to use regulation to represent clients or the public interest on specific matters, this book is organized to: "Enable readers to act effectively in all regulated industries; help non-lawyers become conversant with law; prepare policymakers to adjust the law to accommodate technological change and preserve the credibility of regulation."[2] This vision of "effective regulation" is further explained as follows:

> What regulation must balance is not competing private interests but competing components of the public interest—e.g., long-term societal needs, short-term economic needs, investor satisfaction, affordability, efficient price signals, environmen-

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1. SCOTT HEMPLING, REGULATING PUBLIC UTILITY PERFORMANCE: THE LAW OF MARKET STRUCTURE, PRICING, AND JURISDICTION xix (2d ed. 2021).

2. *Id.* at xxi-xxii.

> tal values, and global competitiveness . . . Effective regulation therefore aims to align private behavior with the public interest. Regulation defines standards for performance, then assigns consequences, positive and negative, for that performance. The common purpose of all regulation is performance . . . . *This view is neither universally shared nor permanently held*.[3]

That goal governs the book's organization into three main sections comprised of twelve chapters. The pithy titles of these sections reflect the utilitarian perspective with which the book is to be read and understood. They are:

Part One - Market Structure: From Monopolies to Competition—Who Can Sell to Whom?;
Part Two - How Much Can Sellers Charge—And Who Decides?; and
Part Three - Jurisdiction: State, Federal and Future

The individual topics under these headings are organized and displayed in an unusually fulsome and easy to follow table of contents.

This ordering may seem counterintuitive and initially may bother someone like me who has designed syllabi for law school regulatory courses. We often instruct our students (and law firm associates) to start with "who has jurisdiction, i.e., the power to decide an issue," and then move on to how prices are regulated and how competition either is or is not permitted within the legally, although not operationally discrete, federal and state jurisdictions. While the author states early on that "the legal lodestar" of regulation is the regulatory statute,[4] the bulk of the book does not deal substantively with statutes until Part Three, the discussion of jurisdiction. When one realizes that it might seem to be obliviously pedantic to tell the prime target audience for this book, the regulators, to approach "effective regulation" by relearning their own authority, the ordering of these subjects makes eminent sense.

Indeed, the decision to focus on market structure first makes sense. When the Federal Power and Natural Gas Acts were adopted in the 1930s, the statutory structure and division of jurisdiction between federal and state authorities reflected the market structure of the time. The immense technological changes that have accompanied the infusion of competition into utility regulation policy has changed market structure and thereby drawn state and federal jurisdiction into more frequent conflict. In terms of market structure, regulators and the regulated are facing questions such as:

- "Which customers require regulation and for what services?"
- "How should end users be permitted to 'shop the market' for energy supplies across what are now wholesale and retail markets while still being tethered to a single delivery distribution/transmission wire or pipeline?"
- "Under what terms should sellers of those commodities and delivery services be allowed access to those customers?"

Those are the types of challenges that Mr. Hempling has identified and tackles in this book.

3. *Id.* at 3, n.4 (emphasis provided).
4. Hempling, *supra* note 1, at 3.

Mr. Hempling approaches market structure at the book's outset from the perspective of "prove to me that utilities still should be regulated as natural monopolies" rather than that natural monopolies are and still should be the norm. He moves from a description and evaluation of the means by which natural monopolies are embedded in law and regulation, running from service territory franchises to statutory "obligations to serve," and the entrenched incumbent utility advantages of service contracts and rights of eminent domain, to the mechanics of how competition should be introduced. The market structures for each of natural gas, electricity and telecommunications are discussed along with representative cases and, in the case of telecommunications, aspects of the Telecommunications Act of 1996, Pub.L. No.104-104, 110 Stat. 56, that altered the relationship between federal and state regulation in that area. Examples of representative state commission actions related to each type of change are provided. Some case citations are recent; others may date to the 1920s. The case citations for each topic discussed are intended to be illustrative but not exhaustive of any regulatory action anywhere.

The book views changes in market control or structure of these industries as key to injecting needed competition. It does focus on the need or desirability to eliminate as many "bottleneck controls of essential facilities" as possible.[5] This antitrust theorem, applied primarily to the electric utility and telecommunications industry, e.g., local telephone exchanges, has often been raised in regulatory proceedings, certainly at the FERC, but not always officially recognized in agency decisions. Many state regulators that evaluate whether or how to inject competition into the markets they regulate will not address the essential facilities doctrine. Indeed, the extended focus on essential facilities raised my eyebrows a bit, but perhaps that was the author's underlying intention as a way of encouraging greater evaluation of the material.

The market structure section also addresses the multiple avenues that might be used to reduce barriers to entry into previously regulated markets where public utilities had been given exclusive service franchises, etc. The book starts from the proposition that if a market is deemed ripe for competition, the incumbents do not warrant **any** preference, including service territories. Notwithstanding many customers' preference to stay with the incumbent utility, regulatory commissions should view such preference as "[A]dvantages [that] flow from government conduct rather than performance merit, they are unearned advantages. They do not arise from 'skill, foresight and industry.'"[6] Similarly, "[W]hat makes immature markets vulnerable to misbehavior, justifying regulatory involvement, is the presence of incumbents that seek to provide the newly competitive services while also providing the monopoly services."[7] There are similar observations throughout Part One. These observations both may pique the reader's interest but also run the risk of distracting the reader's focus from the analysis to the author's opinion.

5. *See id.* at Part 1, Section 4.B.

6. *Id.* at 201.

7. *Id.* at 244.

Part Two is titled: "Pricing, How Much Can Sellers Charge And Who Decides." The discussion is divided into two major foci of analysis: accepted pricing methodologies in "noncompetitive", i.e., cost-regulated, markets; and what constitutes just and reasonable pricing from a regulatory perspective in competitive markets. The first section provides a familiar overview of the principles of the elements of cost-based ratemaking. The discussion is broken down between retail and wholesale jurisdictions.

This section has several strengths not present in other books on public utility economics, ratemaking, etc. First, many of the chapters in this section include drawings, such as Figure 6 that presents a flow/decision chart portraying the decision-making process under basic cost of service principles either faced by a utility or used by a regulator in deciding how to recover costs. Other charts/graphs, etc. take similar forms that graphically illustrate how the principles of the chapter within a section of the book fit together.

Chapter 9, regarding the filed rate doctrine, and Chapter 11, discussing the Mobile-Sierra doctrine, present the most lucid descriptions that I have ever encountered of what those doctrines mean and how they are applied. Chapter 11 starts with the attention-grabbing statement, "In 1956, Dwight Eisenhower was reelected President, Don Larsen pitched baseball's only World Series perfect game,[note omitted] and the U.S. Supreme Court established the *Mobile-Sierra* doctrine."[8] Shortly thereafter, the quandary presented by the Mobile-Sierra doctrine is framed by two examples from California: PG&E's attempt to alter a long-term power sale contract entered into in 1947 (the *Sierra* case portion of Mobile-Sierra) and the 2000 California energy crisis situation that gave rise to the Supreme Court decision in *Morgan Stanley Capital Group, Inc. v. Public Utility District No. 1*, 554 U.S. 527 (2008). The latter case reinterpreted how the Mobile-Sierra concept should be applied to long-term power sales contracts operating under materially changed market conditions after their execution.

For all of its strengths, the discussion in Part Two also epitomizes one of the curiosities about this book's approach. It is not until page 389 that the "public interest" standard of utility statutes is discussed at length. That is the point where I start one of my courses but that's an organizational concept best applied to students and other newbies to the regulatory biz. A book for regulators about better regulation shouldn't have to explain to a regulator how the "public interest" standard is to be applied.

Part Three, "Jurisdiction: State, Federal and Future," is the shortest section of the book. It starts on page 405 and ends on page 481. It consists of just two chapters: one on various aspects of the "federal-state relationship" and the other on "jurisdiction's future." The former focuses on the U.S. Constitutional sources of federal jurisdiction that otherwise supersede state jurisdiction. These include the Commerce Clause, the Tenth Amendment Supremacy Clause, statutory limits on agency authority (federal and state) and the dormant Commerce Clause issues (with no apologies to Justice Thomas or all those doubters of the doctrine's validity). This section also makes one or two sweeping generalizations that might set the experienced practitioner's (as well as Constitutional historians') teeth on

8. Hempling, *supra* note 1, at 386.

edge, such as "Our regulated industries live with two historical legacies: the Framers' 1787 decision to have both federal and state governments, and Congress's 1930s decisions to allocate regulatory powers between those two levels."[9] Upon reflection (or, in other words, "now that I've grabbed your attention"), the statement does make one reflect on the challenge that technological change and the pressure of political concerns such as climate change pose to regulators operating under somewhat antiquated structures.

The chapter on the future of jurisdiction returns to the central theme of analyzing central aspects of utility regulation, such as the obligation to serve, exclusive franchises, market structure and pricing against new market structures. A closing note says it all:

"The questions in all four of these areas—market structure, pricing, jurisdiction and corporate structure—are far from complete. I leave it to readers to raise more questions, and provide answers, as they pursue careers in the regulation of public utility performance."[10]

Current events in the electric utility regulation area present the perfect opportunity to read "Regulating Public Utility Performance." The FERC's newly established task force on electric transmission (FERC Docket No. AD-21-15-000) as well as the currently outstanding Advanced *Notice of Proposed Rulemaking on Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnections* (FERC Docket No. RM21-17-000) address the disconnections in market structure, inconvenient differences between state and federal jurisdiction and the possible disruption of utility business models that are causing both anguish and optimism to those engaged in the process. Mr. Hempling's book provides a uniquely utilitarian and very timely perspective through which to think through these increasingly pressing issues.

9. *Id.* at 408.
10. *Id.*

ALLEGHENY DEF. PROJECT V. FERC: THE JENGA BLOCK PULL FORETELLING A FATAL CRASH OF FERC'S TOLLING ORDER FAÇADE

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I. INTRODUCTION

In *Allegheny Defense Project v. FERC,*[1] (*Allegheny*) the D.C. Circuit Court of Appeals (DC Circuit), acting on rehearing en banc, departed from a fifty-year-old precedent by holding that the Federal Energy Regulatory Commission (FERC) does not "act upon" an application for rehearing within the meaning of section 717(r) of the Natural Gas Act (NGA) by issuing a tolling order that simply precludes an application from being deemed denied and thus denies an applicant their statutory right to seek judicial review.[2] In its holding, the D.C. Circuit amplified that the court, not administrative agencies, retain the power to interpret jurisdictional statutory provisions.[3] The decision carries major weight for the businesses

1. Allegheny Def. Project v. FERC, 964 F.3d 1 (D.C. Cir. 2020).
2. *Id.* at 19.
3. *Id.* at 11-12.

regulated under the NGA, the Federal Power Act (FPA), as well as the customers, landowners and other interested parties involved in FERC regulated industries.[4]

Part II of this note examines the historical and legal context of the D.C. Circuit's Decision in *Allegheny* as well as the procedural and factual background of *Allegheny*. In Part III, this note summarizes the rationale of the D.C. Circuit's ruling. Part IV, explores both the subsequent history and the future implications of that ruling to both FERC regulated industries and others.

II. BACKGROUND

A. Interpretation of the Federal Energy Regulatory Commission's Use of Tolling Orders

FERC has a commonly issued tolling orders, which in FERC's view are equivalent to a grant of rehearing, in order to afford the agency additional time to consider the issues raised in an aggrieved parties application.[5] These FERC tolling orders operate "for an open-ended period of time" during which the tolled application cannot be deemed denied.[6] The consequence of such tolling orders is therefore that judicial review of the aggrieved parties' applications in federal court is delayed until FERC lifts the tolling order and rules on the rehearing.[7] In administrative law the court "generally grant[s] deference to an agency's reasonable interpretation of ambiguity in a statue it administers applying the framework of *Chevron*."[8] Tolling orders have been held permissible by the D.C. Circuit under the NGA since its 1969 decision in *California Co. v. FPC*.[9] In *California Co.*, several energy companies petitioned for review of the Federal Power Commission's (FPC)[10] Area Rate Proceedings, but no ruling on the merits of the energy companies' applications for rehearing had been issued.[11] Rather, the FPC issued a grant of rehearing on all applications, but "was careful to note that it's action 'shall not be deemed a grant or denial of the application on their merits in whole in or part.'"[12]

Notably, the FPC issued the grants of rehearing for the purpose of avoiding the statutory requirement that unless the FPC acts upon the application within 30 days, the application is deemed denied.[13] The energy companies argued that the

4. *Id.* at 5, 23.

5. *Allegheny*, 964 F.3d at 5, 23.

6. *Id.* at 6.

7. *Id.*

8. *Id.* at 11 (citing Chevron, U.S.A., Inc. v. Nat. Res. Def. Council, Inc., 467 U.S. 837 (1984)).

9. *Allegheny*, 964 F.3d at 17 (citing California Co. v. FPC, 411 F.2d 720 (D.C. Cir. 1969)) (holding that the agency's interpretation of the congressional intent of section 717r(a) as a presumption of agency silence was valid).

10. *California Co*., 411 F.2d at 720. FERC is the successor agency to the FPC. Congress transferred this authority in the Department of Energy Organization Act of 1977. *See* Department of Energy Organization Act, 91 Stat. 565 (1977) (codified as amended at 42 U.S.C. § 7101 (2014).

11. *California Co.*, 411 F.2d at 720.

12. *Id.*

13. *Id.*

language of section 717r(a) required the FPC to act on the merits of the rehearing application, within thirty days, and the FPC's failure to act allowed their case to be ripe for judicial review.[14] However, a "two-judge panel" of the D.C. Circuit gave deference to the FPC interpretation of section 717r(a), holding that such a "time honored interpretation of the section involved is worthy of judicial deference."[15]

Thus, the court was "reluctant to impute to Congress a purpose to limit the Commission to 30 days' consideration of applications for rehearing, irrespective of the complexity of the issues involved, with jurisdiction then passing to the courts to review a decision which at that moment would profitably remain under . . . the agency."[16] Since then, courts have long treated FPC's and now FERC's interpretation of section 717r(a) as settled law and significantly, the "public, government, . . . circuits, and the Bar have long relied" on tolling orders as a permissible use of acting upon a rehearing request within 30 days.[17]

B. Factual and Procedural History

In 2015, the Transcontinental Gas Pipeline Co. (Transco) applied for a certificate of public convenience and necessity from FERC in order to develop its Atlantic Sunrise Project (ASP), a $3 billion dollar expansion of the existing Transco natural gas pipeline system to connect abundant Marcellus gas supplies with markets in the Mid-Atlantic and Southeastern United States.[18] Central to Transco's application was the construction of 200 miles of pipeline through Southeastern Pennsylvania.[19] The petitioners, the Erb and Hoffman families (Homeowners), owned properties directly in the path of the ASP.[20] The Homeowners opposed FERC granting Transco's certificate for a variety of reasons, including concerns about the decimation of ecosystems, endangering of stream beds, and that the pipeline would negatively impact sites deserving of historical protection.[21] Additionally, the Environmental Association Petitioners (EAP) opposed the project for similar reasons.[22]

14. *Id*. at 721.

15. *California Co.*, 411 F.2d at 721 (one of the judges assigned to the panel did not participate in the decision and the ruling was *per curiam*).

16. *Id*. at 722.

17. *Allegheny*, 964 F.3d at 23; Delaware Riverkeeper Network v. FERC, 895 F.3d 102, 113 (D.C. Cir. 2018).

18. *Allegheny*, 964 F.3d at 5; see also WILLIAMS, *About the Project*, http://atlanticsunriseexpansion.com/about-the-project/overview.

19. *Allegheny*, 964 F.3d at 5.

20. *Id*.

21. *Id*. at 6.

22. *Id*.; The EAP consisted of Allegheny Defense Project, Clean Air Council, Concerned Citizens of Lebanon County, Heartwood, Lancaster Against Pipelines, Lebanon Pipeline Awareness, and Sierra Club (Allegheny), who filed for rehearing on February 10, 2017. The EAP further consisted of the Accokeek, Mattawoman, and Piscataway Creeks Communities Council Inc. (Accokeek), who filed for rehearing on February 24, 2017. *See Transcon. Gas Pipe Line Co., LLC*, 161 FERC ¶ 61,250 at P 2 (2017) [hereinafter *Transco I*].

On February 3, 2017, FERC granted Transco a certificate of public convenience and necessity for the ASP project.[23] Both the Homeowners and the EAP moved to stay the Certificate Order pending FERC's rehearing decision and filed applications for rehearing before FERC.[24] The EAP's application was filed February 10 and 24, 2017, while the Homeowners' was filed on March 6, 2017.[25] On March 13, 2017, the first business day after the thirty (30) day statutory time period for the Commission to act on the EAP's first application, FERC's Secretary issued a tolling order that applied to all three rehearing applications.[26] In particular, the order "granted [rehearing] for the limited purpose of further consideration" for an open-ended period of time and by virtue of its issuance, the applications for rehearing would not be deemed denied.[27] Following the issuance of the tolling order, the Homeowners and EAP petitioned for review of both the Certificate and the Tolling Order in the D.C. Circuit.[28] In response, Transco and FERC "moved to dismiss the petitions for lack of jurisdiction, contending that the petitions were 'incurably premature' because . . . [FERC] had not taken final agency action" on the rehearing requests pursuant to section 717r of the Natural Gas Act.[29]

As the Homeowners and EAP waited for FERC "to resolve their rehearing applications, Transco pressed forward with its condemnation action against the Homeowners in the United States District Court for the Eastern District of Pennsylvania."[30] In August 2017, the district court ruled on Transco's eminent domain case granting partial summary judgement and a preliminary injunction to Transco.[31] In doing so, the district court provided Transco the immediate possession of the right of way to build its pipeline over the Homeowners' land.[32] The following week, seven months after a motion to stay was filed, FERC denied it.[33] In doing so, FERC found the environmental harm and air pollution concerns as insufficient to justify a stay.[34]

On September 5, 2017, Transco requested from FERC an order to allow it to begin construction.[35] Ten days later, the Construction Order was granted while

23. *Allegheny*, 964 F.3d at 6.

24. *Id.*

25. *Id.* Two different EAP members filed for rehearing separately in what was later a consolidated action. On February 10, 2017 Allegheny filed a request for rehearing and a motion for stay pending resolution of its rehearing request and any further judicial review of FERC's February 3, 2017 order granting Transco a certificate of public convenience and necessity. Accokeek followed suit on February 24, 2017 resting upon the same arguments set forth in Allegheny's February 10, 2017 pleading. *See Transco I*, *supra* note 22, at P 2.

26. *Allegheny*, 964 F.3d at 6.

27. *Id.* at 7.

28. *Id.*

29. *Id.*

30. *Allegheny*, 964 F.3d at 7.

31. *Id.* at 8.

32. *Id.*

33. *Id.* (citing *Transcon. Gas Pipe Line Co.*, 160 FERC ¶ 61,042 (2017)) [hereinafter *Transco II*].

34. *Allegheny*, 964 F.3d at 8 (citing *Transco II*, *supra* note 33, at P 8).

35. *Id.*

the Homeowners' and EAP's rehearing applications remained pending.[36] As the thirty day statutory mark approached, the EAP immediately sought rehearing and rescission of the Construction Order which led FERC to issue another tolling order.[37] Finally, nine months after the Homeowners' first application for rehearing, FERC denied the rehearing but by that time Transco had already started construction on the Homeowners' property.[38] Following the denial, the Homeowners and EAP filed a second petition with the D.C. Circuit, and argued that FERC "failed to support its determination that the Project served a market need as required by the Natural Gas Act, and denied them due process by allowing construction to begin before any court could review the Certificate Order."[39] Additionally, three months after the denial of the rehearing for the certificate order, FERC denied the rehearing of the Construction Order.[40] Notably, "by the time . . . [the court] heard oral arguments . . . on the merits of the Homeowners' and [EAP's] petitions for review, the pipeline had been built and operational for two months.[41]

The D.C. Circuit Panel held that the "motions to dismiss the first round of petitions [were] moot, reasoning that the second round gave the D.C. Circuit jurisdiction to review the Certificate Rehearing Order."[42] The panel rejected the Homeowners' and EAP's arguments and denied the petition for review.[43] In response, the Homeowners sought, and The United States Court of Appeals for the District of Columbia Circuit granted, "rehearing *en banc* and vacated the panel's judgement."[44]

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36. *Id.*

37. *Id.*

38. *Allegheny*, 964 F.3d at 8.

39. *Id.* at 9.

40. *Id.* (citing *Transcon. Gas Pipeline Co.*, 162 FERC ¶ 61,192 (2018)).

41. *Id.*

42. *Allegheny*, 964 F.3d at 9.

43. *Id.*; *See* Allegheny Def. Project v. FERC, 932 F.3D 940, 945-48 & n.1 (D.C. Cir. 2019) (discussing that the Homeowners and EAP argued FERC: "[(1)] improperly conducted its environmental assessment under NEPA [(2)] failed to substantiate market need for the Project as required by the Natural Gas Act, and [(3)] denied them due process by authorizing construction to commence before the issuance of the Certificate Order could be judicially reviewed." The court found none of the arguments successful).

44. Allegheny Def. Project v. FERC, 964 F.3d 1, 7 (D.C. Cir. 2020). Rehearing *en banc* is the only way a circuit court can reverse its own precedent. *See* United States v. Doe, 730 F.2d 1529, n. 2 (D.C. Cir. 1984) (stating "[The D.C. Circuit] cannot overrule the decisions of another panel of this court; a panel's decision may only be rejected by a court *en banc*")). Typically, courts disfavor a rehearing *en banc* and usually they will not be ordered unless: "(1) *en banc* consideration is necessary to maintain uniformity of the court's decisions; or (2) the proceeding involves a question of exceptional importance." Fed. R. App. P. 35. Thus, it is important to note that the panel that ruled against the Homeowners could not reverse its own precedent, even if the panel thought the Homeowners were right. *See Doe*, 730 F.3d at n.2; *see also* Phillip M. Kannan, *The Precedential Force of Panel Law*, 76 MARQ. L. REV. 755 (1993).

C. Interpretation of Section 717r(a) of the NGA falls Directly to the Court and Not to FERC

In examining the question whether the statutory text of the NGA permits FERC's use of tolling orders to delay judicial review, the D.C. Circuit first addressed who retained the power to interpret the ambiguities of section 717r(a) of the NGA.[45] The D.C. Circuit noted that in administrative law, deference is generally granted "to an agency's reasonable interpretation of ambiguity in a statute it administers, applying the framework of *Chevron*."[46] Under the *Chevron* framework, FERC asked the D.C. Circuit to defer to their reasonable interpretation of the ambiguity in section 717r(a).[47]

However, the Court held that it was unnecessary to employ *Chevron* deference, because FERC was not "[interpreting an] ambiguity in a statute it administer[ed]."[48] The rationale underlying the court's decision, was that "[f]ederal agencies do not administer and [possess] no relevant expertise in enforcing the boundaries of the court's jurisdiction."[49] Notably, the court held that section 717r(a) spoke "directly to federal court jurisdiction to review Commission order."[50] According to the Court, the jurisdictional provisions of section 717r(a) were not administered by FERC and thus *Chevron* deference could not be afforded to FERC in this case.[51] Therefore, the D.C. Circuit held that interpretation of section 717r(a) of the NGA fell directly to the court and not to FERC.[52]

D. Section 717r(a) of the NGA Lays out Unambiguous Requirements

The question of whether FERC possessed "the authority [under section 717r(a)] to issue the Tolling Order that served solely to override the deemed denied provision and thereby prevent . . . judicial review until whenever [FERC] acted" remained before the court.[53] Before turning to this issue, the D.C. Circuit noted that while a tolling order delays judicial review, it does not delay a natural gas company's ability to judicially take possession of the aggrieved parties' land through the use of eminent domain and then begin construction and operation of the pipelines.[54] Despite placing aggrieved landowners at a decided disadvantage

45. *Allegheny*, 964 F.3d at 9, 11.

46. *Id.* at 11 (referencing the Chevron Two-Step Test laid out by Justice Stevens in *Chevron*, *U.S.A., Inc.*, 467 U.S. at 837).

47. *Id.*

48. *Id.* at 11.

49. *Allegheny*, 964 F.3d at 11.

50. *Id.* at 12.

51. *Id.*

52. *Id.*

53. *Allegheny*, 964 F.3d at 12.

54. *Id.* at 10-11. FERC Commissioner Glick stated that FERC can and should do better, as it has created a regulatory construct that "allows a pipeline developer to build its entire project while simultaneously preventing opponents of that pipeline from having their day in court, [which] ensures that irreparable harm will occur before any party has access to judicial relief." *Id.* (quoting *Spire STL Pipeline LLC*, 169 FERC ¶ 61,134 at P 33 (2019) (Glick, Comm'r, dissenting).

in adjudicating their rights, the process of issuing tolling orders, and thus delaying judicial review until FERC acts has become "virtually automatic."[55]

As the D.C. Circuit notes in *Allegheny*, the ubiquity of FERC's use of tolling orders is illustrated by FERC's issuance of them in "all thirty-nine cases [over the past twelve years], in which landowners sought rehearing in a proceeding involving natural gas pipeline construction."[56] FERC uses its "tolling orders to split the atom of finality . . . [or] in other words, render [FERC] decisions akin to Schrodinger's cat: both final and not final at the same time."[57] Furthermore, this "asymmetrical finality timetable has become common place" as seen through FERC authorizing "construction to begin before resolving the rehearing requests on the merits in 64%" of its 114 natural gas pipeline cases from October, 2008 to February, 2019.[58]

In interpreting section 717r(a) the D.C. Circuit's analysis "[began] with the statutory text, and [ended] there as well."[59] The D.C. Circuit noted that section 717r(a)'s requirement for the "filing of an application for rehearing as precondition to judicial review" of Commission action was uncontested.[60] However, according to the Court, once an application is filed, section 717r(a) is explicit in its specifications of what FERC's next steps are.[61] Specifically FERC can, "(i) grant rehearing, (ii) deny rehearing, (iii) abrogate its order without further hearing, and (iv) modify its order without further hearing."[62] The D.C. Circuit further noted that section 717r(a) is unambiguous in the ramifications of FERC's failure to act upon the application in the prescribed time, the application may be deemed denied.[63]

The D.C. Circuit held that by referencing in the deemed-denied provision "what [FERC] has—or has not—done 'upon the application,' Congress signaled that the kinds of actions that prevent deemed denial are the four dispositions just listed."[64] Thus, section 717r(a) is unambiguous in establishing that if FERC fails

55. *Id.* at 9.

56. *Allegheny*, 964 F.3d at 9.

57. *Id.* at 10 (discussing that tolling orders are final enough for pipeline companies to take property by eminent domain and final enough for construction to be greenlight construction and operation, but they are not final enough for aggrieved parties to seek judicial review).

58. *Id.*; *See* May Van Rossum, *People's Dossier of FERC Abuses: Stripping People's Rights*, DELAWARE RIVER KEEPER NETWORK, https://www.delawareriverkeeper.org (Discussing the harms inflicted by FERC's delays in responding to rehearing request which include projects being fully constructed and operational, subjecting properties to deforestation, inflicting irreparable harm on forested wetlands, destroying maple enterprise operations, right of-way clearing, trenching, and deployment of pipe all before the aggrieved landowner's get their day in court).

59. *Allegheny*, 964 F.3d at 12 (quoting Nat'l Ass'n of Mfrs. v. Dep't of Defense, 138 S. Ct. 617, 631 (2008)).

60. *Id.*

61. *Id.* at 13.

62. *Id.* (quoting 15 U.S.C. § 717r(a) (2005) (breaking down the language of section 717r(a) which states: Upon such application the Commission shall have power to grant or deny rehearing or to abrogate or modify its order without further hearing).

63. *Allegheny*, 964 F.3d at 13.

64. *Id.*

to take one of the enumerated actions within the statutorily prescribed thirty day window, the application may be deemed denied and the applicant can seek judicial review of "the now-final agency action."[65]

III. ANALYSIS

A. FERC Failed to Act Upon a Request Within the Meaning of 717r(a) and its Inaction Triggered Judicial Review.

FERC believed that the use of its tolling orders amounted to an action upon the application because it "included language stating that 'rehearing is hereby granted.'"[66] However, the D.C. Circuit held that section 717r(a) "is not such an empty vessel [and] [t]he question is not one of labels but of signification."[67] Therefore, the D.C. Circuit noted that the question before them was whether the tolling order "amount[ed] to a 'grant' of rehearing within the meaning of a statute, or instead amount only to inaction on the application, . . . [thereby triggering] judicial review as a deemed denial."[68]

First, in addressing this question, the D.C. Circuit noted that "a 'grant' of rehearing, as opposed to inaction on an application for rehearing requires some substantive engagement with the application."[69] Notably a 'grant' of rehearing must do more than grant additional time.[70] According to the court, FERC was emphatically "doing one thing, and one thing only: [i]t [was] preventing 'timely-filed rehearing request' from being 'deemed denied' by operation of law.'"[71] The text of the NGA lends no justification for FERC to "have it both ways, claiming to have granted rehearing in one breath, while promising in the next breath that it will decide in some future order whether to grant rehearing or not."[72] When issuing tolling orders the court held that FERC is merely "kicking the can down the road."[73]

Second, the D.C. Circuit held that the tolling order only stalled for time to allow FERC the opportunity act because the Secretary was forbidden from acting on the application.[74] The court noted that the Secretary had "not been delegated any authority to 'act on' the rehearing application, . . . [but had only been delegated authority to] 'toll the time for action on requests for rehearing'"[75]

65. *Id.*
66. *Id.*
67. *Allegheny*, 964 F.3d at 13.
68. *Id.*
69. *Id.*
70. *Id.*
71. *Allegheny*, 964 F.3d at 13.
72. *Id.* at 14.
73. *Id.* at 13-14.
74. *Id.*
75. *Allegheny*, 964 F.3d at 13-14.

Third, in answering whether or not the tolling order 'granted' rehearing, the D.C. Circuit held that the tolling order created an "unbounded amount of additional time, within which rehearing could never be deemed denied."[76] In the present case, FERC took nine months compared to their typical seven month average "from tolling order to actual rehearing decision on landowner's decisions in pipeline cases."[77] The D.C. Circuit held that FERC, by issuance of its tolling orders, attempted to delete the statutorily prescribed time limit and the deemed denied provision.[78] In other words, the court explained, FERC had attempted to rewrite section 717r(a) "to say that its failure to act within thirty days means nothing."[79] But, the court concluded, neither FERC nor a court possesses the authority to rewrite legislation and "render statutory language a nullity."[80]

Fourth, the D.C. Circuit referenced that Congress only permits agencies to "modify the consequences of their inaction" when Congress" says so explicitly."[81] As an example, it notes that Congress kept FERC "on a tight leash" when it amended the NGA's close relative the FPA to limit the time FERC could take to act on certain applications.[82] Furthermore, section 717r(a) is silent on any authority to toll, and thus according to the court the "textual omission pulls the rug out from under [FERC's] claim of the unwritten and unilateral power to indefinitely evade a deemed denial."[83]

Fifth, the only question the court decided was that FERC is unable to issue a tolling order for the purpose of modifying "the statutorily prescribed jurisdictional consequences of its inaction."[84] However, the court noted that FERC need not make a decision upon the application within the statutorily prescribed timeframe of thirty days.[85] Thus, even if FERC fails to act upon the application during thirty-day timeframe, section 717r(a) provides FERC additional time to render a decision by stating: "[u]ntil the record in a proceeding shall have been filed in a court of appeals," [FERC] "may at any time, upon reasonable notice and in such manner as it shall deem proper, modify, or set aside, in whole or in part, any finding or order made or issued by it under the provisions of the NGA."[86] The section 717r(a) approach, "unlike [FERC's], ensures that [FERC's] additional time for action comes with judicial superintendence and the opportunity for the applicant to seek

76. *Id*. at 14 (citation omitted).

77. *Id.* at 15.

78. *Id*.

79. *Allegheny*, 964 F.3d at 15.

80. *Id*.

81. *Id.* (noting that Congress has been explicit in limiting the leeway an agency has when modifying the consequences of its inaction as seen in 15 U.S.C. § 78s(b)(2)(A), (C) in which the Securities and Exchange Commission fails to act, the Commission may extend its initial period to act only under limited, specific circumstances).

82. *Id*. (citing 16 U.S.C. § 824b(a)(5) (2015)).

83. *Allegheny*, 964 F.3d at 16.

84. *Id.*

85. *Id.*

86. *Id*. at 16-17 (quoting 15. U.S.C. § 717r(a)).

temporary injunctive relief if needed"[87] Thus, the D.C. Circuit concluded that the tolling order was not an act upon the Homeowner's and EAP's applications within the meaning of section 717r(a).[88]

B. Subject Matter Jurisdiction Attaches: Granting of Certificate of Convenience Upheld

As a result of FERC's tolling orders being unable to fend off the Homeowner's and EAPs ability to seek judicial review, their initial petitions for review "were properly before [the] court for review."[89] Federal subject matter jurisdiction attached to the Homeowner's and EAP's initial petitions for review as the result of FERC's failure to act upon their rehearing requests within thirty days of the filing of their rehearing applications.[90] The initial petitions challenged FERC's findings that Transco had met its burden of showing market need for "its proposed transportation of natural gas."[91] FERC found Transco satisfied the market need requirement through Transco's reliance on precedent agreements, "comments by two-shippers and one end-user, [as] well as a study . . . all of which reinforced the [domestic] demand for natural gas shipments."[92] As a result the court held that the Homeowner's and EAP's petitions fell short and denied all four petitions for review, as well as the motions to dismiss these petitions.[93]

C. Judger Henderson's Allegheny Partial Dissent and the Fight for a Fifty-Year-Old Precedent

In writing her partial dissent, Circuit Judge Henderson voiced a similar concern as that discussed in the majority opinion, namely that FERC, by issuing tolling orders for the purpose of avoiding the deemed denied provision, creates an inherent dilemma for the Homeowners.[94] However, she believed that the majority opinion disregarded stare decisis and reached a "conclusion without proper regard for the 'extent' to which tolling orders [had] been upheld."[95] Since 1969, the courts have consistently interpreted that FERC's use of tolling orders are a functional equivalent to an 'act' upon applications under section 717r(a).[96] Overturning such precedent is not like rewriting section 717r(a) on a blank piece of paper, but rather is "constricted by the 'special force' of *stare decisis*, which bars overruling precedent without 'special justification.'"[97]

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87. *Allegheny*, 964 F.3d at 17.
88. *Id*.
89. *Id.* at 19.
90. *Id.*
91. *Allegheny*, 964 F.3d at 19.
92. *Id.*
93. *Id.*
94. *Id.* at 25 (Henderson, J., dissenting).
95. *Allegheny*, 964 F.3d at 23 (Henderson, J., dissenting).
96. *Id.* (citing Cal. Co. v. Fed. Power Comm'n, 441 F.2d 720, 722 (D.C. Cir. 1969)).
97. *Allegheny*, 964 F.3d at 23 (Henderson, J., dissenting) (quoting Patterson v. McLean Credit Union, 491 U.S. 164, 172 (1989) (emphasis in original); Allen v. Copper, 140 S. Ct. 994 (2020).

According to the dissent, there are several conditions under which a circuit court may reevaluate its own statutory interpretation.[98] First, a circuit court may reevaluate its own statutory interpretation when other circuits establish a distinguishable, but persuasive construction of the statute.[99] Second, a circuit court may reevaluate its own statutory interpretation if the "*en banc* court 'decides that [a] panel's holding on an important question of law was fundamentally flawed.'"[100] However, the dissent reasoned that none of these factors are present in *Allegheny* to support a reversal of *California Co.*[101] Furthermore, the dissent reasoned that the majority opinion overturned precedent to which the political branches theoretically acquiesced, and could have written out of the statute if they opposed.[102] Thus by overturning *California Co*., the majority "[drew] the judiciary into a policy making role" and overruled precedent on which the "public, government, . . . circuits, and the Bar have long relied."[103]

D. Stare Decisis is not the Berlin Wall, it is Permeable

Thus, the dissent (and previously FERC) argued that stare decisis precludes the D.C. Circuit from overruling *California Co. v. Federal Power Commission*,[104] in which the D.C. Circuit first upheld the use of the tolling order, "without the benefit of oral argument."[105] However, in the majority opinion the Court noted that in reaching that decision, no one, including the panel, could have "foreseen [FERC's] routinization of the [unbounded length] of tolling orders."[106] Further emphasizing this point, the Court noted the landowner's detriment created by this tolling order practice could not have been foreseen because *California Co.* involved rate setting rather than pipeline construction.[107] Furthermore, the D.C. Circuit held that "*stare decisis* principles do not require us to continue down the wrong path."[108] The Court recognized, in agreement with the dissent, that *stare decisis* differs in application to circuit precedent from its application to Supreme Court precedent.[109]

In reviewing circuit precedent, a court can reevaluate its own statutory interpretation if the *en banc* court "decides that [a] panel's holding on an important question of law was fundamentally flawed."[110] However, the majority diverged

98. *Allegheny*, 964 F.3d at 23 (Henderson, J., dissenting)
99. *Id*. at 24 (quoting *Patterson*, 491 U.S. at 173).
100. *Id*.
101. *Id.* at 24.
102. *Allegheny*, 964 F.3d at 24-25 (Henderson, J., dissenting).
103. *Id.* at 23, 25.
104. 411 F.2d 720 (D.C. Cir. 1969).
105. *Allegheny*, 964 F.3d at 17.
106. *Id*. (noting that panels followed *California Co.*'s precedent without further analysis).
107. *Id.* at 17-18.
108. *Id.* (emphasis in original).
109. *Allegheny*, 964 F.3d at 18.
110. *Id.* Generally, cases that come before a United States courts of appeals are heard in front of a three-judge panel. *See* Fed. R. App. P. 35; 28 U.S.C. § 46 (1970). This three-judge appellate court "makes the decision of a division, the decision of the court, unless rehearing [e]n banc is ordered." Reviser's Note to 28 U.S.C. §

from the dissent, in holding that the Court may also set aside circuit precedent "when intervening developments in the law . . . have removed or weakened the conceptual underpinnings from the prior decisions."[111] In light of these principles and in contrast to the dissent, the court held that the panel's acceptance of tolling orders in *California Co.* "is both 'fundamentally flawed' and irreconcilable with intervening Supreme Court decisions in two respects."[112] First, intervening precedent makes clear that the court "must enforce plain and unambiguous statutory language," and "the statute that Congress enacted."[113]

Second, intervening Supreme Court and circuit precedent indicates that *Chevron* deference to an agency's interpretation of a statutory provision is inapplicable when the statutory provisions involve "the boundaries of the courts' jurisdiction," a matter over which federal agencies "have no relevant expertise."[114] Thus, the D.C. Circuit held that panel's approach to statutory construction in *California Co*. was "fundamentally flawed and grounded in a mode of statutory construction that has been foreclosed by the Supreme Court."[115] *Stare decisis* in this regard, was not a wall standing in the way of the D.C. Circuit, it was permeable.[116] Thus, the Court's holding that FERC's tolling orders were not grants of rehearing because they failed to act upon the rehearing application by taking one of the unambiguous actions spelled out in section 717r(a), is permissible.

E. The Court Dismantled Only One Web Ensnaring Landowners: Circuit Judge Griffith's Concurring Opinion

The D.C. Circuit's decision was based in part on finding the appropriate weight and deference to give precedent.[117] Circuit Judge Griffith in his concurring opinion warned that delayed judicial review was only a singular strand in a "web that can ensnare landowners in pipeline cases," and that it "is not the primary

46(c) (1970). A court can sit en banc during a rehearing of a panel decision or even on the initial hearing of a case. 28 U.S.C. § 46(c) (1970). When the court sits en banc, it consists of "all circuit judges in regular active service." *Id.* En banc decisions carry great weight and "because en banc courts 'are convened only when extraordinary circumstances exist,' they make 'for more effective judicial administration' where '[c]onflicts within a circuit will be avoided' and '[f]inality of decision in the circuit courts of appeal will be promoted.'" Alexandra Sadinsky, *Redefining En Banc Review in the Federal Courts of Appeals*, 82 FORDHAM L. REV. 200, 2011 (2014) (quoting United States v. Am.-Foreign S.S. Corp., 363 U.S. 685 (1960). Further, courts of appeals are often the court of last resort due to the discretionary nature of grants of Certiorari by the Supreme Court. *Id.* at 2004. Thus, en banc review allows every judge on the appellate court to weigh in on the case and controversy or overturn a decision reached by the original three-judge panel and often determine the "major doctrinal trends of the future for their court." *Id.* at 2030.

111. *Allegheny*, 964 F.3d at 18 (quoting United States v. Burwell, 690 F.3d 500, 504 (D.C. Cir. 2012).

112. *Id.* (citing Critical Mass Energy Project v. NRC, 975 F.2d 871, 876 (D.C. Cir. 1992); *Burwell*, 690 F.3d at 504).

113. *Id.* (citing and quoting Obduskey v. McCarthy & Holthus LLP, 139 S. Ct. 1029, 1040 (2019).

114. *Id.* at 12; *see, supra*, notes 45-52 (discussing the inapplicability of *Chevron* deference to statutory provisions the agency is not "charged with administering").

115. *Allegheny*, 964 F.3d at 18.

116. *Id.*

117. *Id.* at 12.

driver of unfairness" to landowners.[118] Further, the concurrence recognized that "one cannot review the procedural history of this case, and others like it, without concluding that something is amiss."[119] Property is routinely handed over to pipeline companies only to be "irreparably transformed, all without judicial consideration of the crucial question: Should the pipeline exist?"[120] This injustice results from the unintentional comingling of three factors: "delayed judicial review, uninterrupted construction, and district courts' swift transfer of property."[121] The concurring opinion discusses each of these factors in detail, as discussed below.

1. Delayed Judicial Review

According to the *Allegheny* concurrence, the NGA explicitly provides federal courts jurisdiction to hear reviews of FERC's certificate orders in two possible scenarios.[122] The first scenario in which federals courts receive jurisdiction occurs when FERC fails to "act upon" the application for rehearing within the statutorily prescribed timeline in section 717r(a) of the NGA.[123] This scenario was the subject of the *Allegheny m*ajority's opinion in holding that the tolling order did not "act upon" the application for rehearing.[124] The second scenario occurs once "FERC rules on the *merits* of a granting petition for rehearing."[125] The *Allegheny* concurrence notes however, this "caveat is important because [FERC] can grant rehearing *without* making a merits decision."[126] This conclusion stems from there being no indication that section 717r(a)'s use of "grant . . . rehearing" was equivalent to ensuring FERC made a decision on the merits.[127] Additionally, the majority afforded no guidance on the determination of what qualifies as a "grant" of rehearing.[128] As a result, FERC is free to grant rehearing "by agreeing to consider the applicant's arguments," or in the words of the *Allegheny* concurrence "deciding to decide," which might still leave open the possibility for undue delay.[129]

2. Uninterrupted Construction

Additionally, the *Allegheny* concurrence emphasizes that delayed or deferred judicial review is *not* one of the major contributors of unfairness to landowners in pipeline cases.[130] The harms caused to the landowners are created by and stem from the steps FERC takes in the interim between granting a certificate and acting

118. *Allegheny*, 964 F.3d at 20 (Griffith, J., concurring).
119. *Id*.
120. *Id*.
121. *Id.*
122. *Allegheny*, 964 F.3d at 20 (Griffith, J., concurring).
123. *Id.*
124. *Id.*
125. *Id*. (emphasis in original).
126. *Allegheny*, 964 F.3d at 20 (Griffith, J., concurring) (emphasis in original).
127. *Id.*
128. *Id*. at 21.
129. *Id.*
130. *Allegheny*, 964 F.3d at 21 (Griffith, J., concurring).

upon a rehearing application, such as granting construction orders.[131] The *Allegheny* concurrence, referencing the majority's opinion, noted that FERC has begun to change course by "amend[ing] its rehearing regulations to 'preclude [ ] the issuance' of a construction order 'while rehearing of the initial order is pending.'"[132] If FERC continued with this practice it would significantly limit the impact of the issue the D.C. Circuit addressed in *Allegheny*. A challenge under the Administrative Procedure Act might be ripe, the concurrence stated, if FERC reverts back to issuing the construction orders while a case is pending rehearing.[133]

3. District Court's Swift Transfer of Property

The *Allegheny* concurrence also notes, however, that even if FERC keeps its new policy of not authorizing construction orders in place, landowners are still at risk. If the certificate order has issues and has not been stayed, the new rule still "does not . . . prevent eminent domain proceedings from going forward based on the underlying certificate order."[134] Eminent domain proceedings are the final strand of the web that can ensnare landowners.[135] Notably, the NGA is silent when it comes to "prevent[ing] a district court from holding an eminent-domain action in abeyance until [FERC] completes its reconsideration of the underlying certificate order."[136] The *Allegheny* concurrence further suggests that a grant of rehearing for a certificate order should be deemed as non-final, thus rendering it as "an invalid basis for transferring property by eminent domain."[137] Thus, the *Allegheny* concurrence concludes that while eliminating FERC's use of tolling orders as a stalling tactic was necessary, even after the decision FERC still retains vast power to postpone review by granting rehearing.[138] However, the court retains an arsenal to mitigate future potential abuse of this power.[139]

IV. SUBSEQUENT HISTORY AND FUTURE IMPLICATIONS

In its majority decision in *Allegheny*, the D.C. Circuit "breaks new ground as the first court of appeals to disapprove FERC's use of tolling orders since the Natural Gas Act became law in 1938."[140] The rationale and approach taken by the D.C. Circuit is likely to be replicated by sister circuits and will likely play a sub-

131. *Id.* at 1, 21 (Griffith, J., concurring).

132. *Id.*

133. *Id.* at 22; *See also* Recent Changes in Commission Rehearing Practice: Item A-3 (Sept. 17, 2020) (transcript available https://www.ferc.gov/news-events/news/recent-changes-commission-rehearing-practice-item-3) (discussing an overview of changes in the FERC's practices concerning requests for rehearing following the in *Allegheny)*.

134. *Allegheny*, 964 F.3d at 22 (Griffith, J., concurring).

135. *Id*.

136. *Id*.

137. *Id*.

138. *Allegheny*, 964 F.3d at 22. (Griffith, J., concurring).

139. *Id*.

140. *Id.* (Henderson, J., dissenting) (referencing holdings of the Fifth, Fourth, and First Circuits opposing the D.C. Circuit's position and upholding the use of tolling orders).

stantial role in guaranteeing fair proceedings for both landowners, pipeline companies and others.[141] As a result of the D.C. Circuit's holding FERC can no longer use tolling orders as a means to indefinitely postpone ruling on the merits of a request for rehearing of a FERC order.[142] Notably, under this ruling FERC is not required to decide rehearing requests within the thirty-day statutorily prescribed window.[143]

However, following the *en banc* decision in *Allegheny*, FERC made it explicitly clear that FERC is halting its use of tolling orders in proceedings arising under the NGA and FPA.[144] Rather than issuing tolling orders, FERC is issuing "one of two types of notices no earlier than the 31st day after rehearing is received: a Notice of Denial of Rehearing by Operation of Law, or a Notice of Denial of Rehearing by Operation of Law and Providing for Further Consideration."[145] The Notice of Denial of Rehearing by Operation of Law indicates to the applicants for rehearing and the public that FERC intends to not issue a merits order response to the request for rehearing.[146] The Notice of a Denial of Rehearing by Operation of Law and Providing for Further Consideration, goes further in stating FERC's "intention to issue a further order addressing issues raised on rehearing.[147]

While FERC has taken some steps towards remedying the issue of tolling orders, there still remains a gap in which Pipeline companies can still resort to eminent domain proceedings while an appeal is pending.[148] However, nothing in the NGA prevents a landowner from seeking a stay or a district court from holding an eminent domain action in abeyance until FERC grants rehearing.[149]

V. CONCLUSION

Although the D.C. Circuit was very narrow in the question it addressed, it provided an accommodation for the interested parties involved. FERC cannot use a tolling order as the sole means of postponing judicial review on the merits of an appeal of FERC's orders.[150] While beneficial to the landowners, this decision does not negate the possibility of pipeline companies resorting to eminent domain pro-

141. *Id.* at 22 (Griffith, J., concurring).

142. *Allegheny*, 964 F.3d at 19.

143. *Id.* at 16.

144. *Recent* Changes in Commission Rehearing Practice: Item A-3 (Sept. 17, 2020) (transcript available https://www.ferc.gov/news-events/news/recent-changes-commission-rehearing-practice-item-3).

145. *Id.* FERC states that these Notices have important features in common "they both acknowledge that, because the 30-day deadline in the [NGA] or the [FPA] has passed, rehearing may be deemed denied by operation of law." Additionally, these Notices make public the status of the rehearing request but neither Notice rules on the rehearing request. *See Id.*

146. *Id.*

147. *Id.*; *see Allegheny*, 964 F.3d at 16-17 (quoting 15. U.S.C. § 717r(a)) (discussing FERC's authority to "modify order set aside" the underlying orders until the record is filed with the reviewing court).

148. *Allegheny*, 964 F.3d at 1, 10 n.2.

149. *Id.* at 22 (Griffith, J., concurring).

150. *See id.* at 19.

ceedings while an appeal is pending in order to push forward the pipeline construction process.[151] Conversely, eminent domain can be held in abeyance if landowners show on the merits that they have a likelihood of prevailing in their appeals.[152] There are many avenues for the court to further guarantee fair proceedings for both landowners and pipeline companies and the D.C. Circuit took a major step in that direction.[153] The D.C. Circuit decision was the pull of a block on a Jenga tower that toppled FERC's stalling tactic of issuing tolling orders and a move to develop more fair proceedings for customers, landowners and other interested parties involved in FERC regulated industries.[154]

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151. *See Allegheny*, 964 F.3d at n.2.

152. *See id.* at 22 (Griffith, J., concurring).

153. *Id*.

154. *Id.*

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