ENERGY LAW JOURNAL

Volume 42, No. 1 2021

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The faculty, administration and students of The University of Tulsa College of Law express our appreciation for the support, mentorship and dedication shown to our students by the Energy Bar Association (EBA) and the professional board of the *Energy Law Journal* (*ELJ*). High-quality experiential learning is a major facet of the TU Law experience, and students at TU Law have been privileged to edit the *ELJ* for more than 20 years. This opportunity has instilled in our students a culture of professionalism and accountability while introducing them to cutting-edge issues in energy, environmental and regulatory law. In addition, during the last decade alone more than 20 TU Law students have had scholarly papers accepted for publication by the *ELJ*, providing these emerging experts with exposure to a readership comprised of thousands of leaders in their fields and enabling them to work closely with professional editors to meet the journal's rigorous standards. The EBA's investment in our students has paid enormous dividends, both during their education and after graduation. Past *ELJ* editors from TU Law work as counsel to small independent oil companies and in the legal departments of the world's largest integrated energy companies. They serve the public as consumer representatives in utility rate cases and as counsel for major state environmental protection agencies, national energy-related trade groups and environmental advocacy groups. In each case, our graduates' ability to contribute to their respective fields derives, in large part, from their *ELJ* experience. We look forward to working closely with the EBA for many years to come.

Lyn S. Entzeroth
Dean and Dean John Rogers
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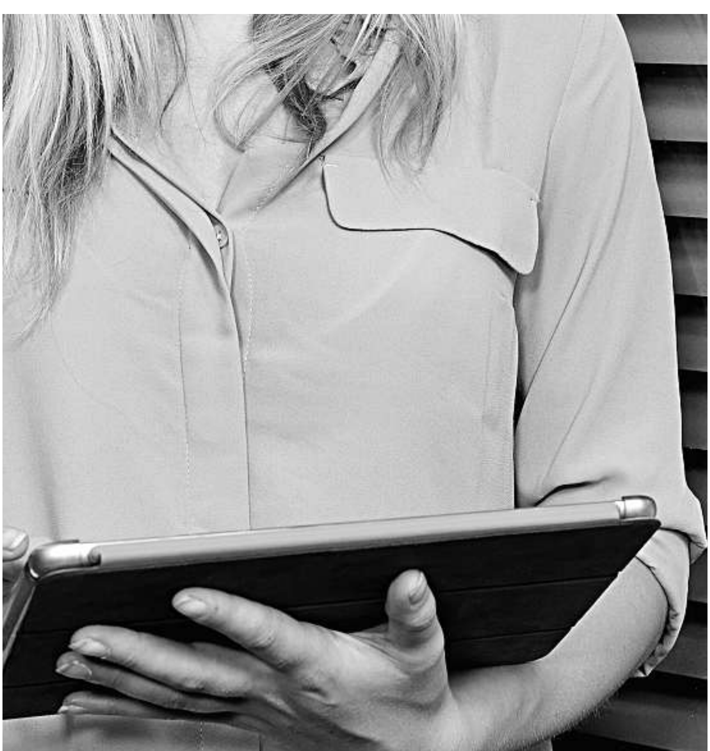

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Energy Law Journal
Editorial Policy

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. 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 *Journal* is free to the public online. Annual subscriptions to receive hard copies of the *Journal* for domestic members are $35, for international members $45, non-members $50 for domestic subscriptions, and $60 for international subscriptions. 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) Website is on-line on the Internet at www.eba-net.org. The Website contains a potpourri of useful information about the EBA, the Charitable Foundation of the Energy Bar Association (CFEBA), and the Foundation of the Energy Law Journal (FELJ). The latest issues of EBA Brief, a quarterly newsletter published by the Foundation of the Energy Law Journal and the Energy Bar Association, are available through the EBA website.

Looking to hire someone? Looking for a new job? If so, you will want to look at the EBA Career Center at https://careers.eba-net.org/. You may post job listings as well as review current available positions nationwide.

Finally, the Website contains usual and customary items that an association would have. For example, there is information about membership and benefits, various directories, meetings and conference information, and a list of frequently-called numbers. Dues and conference fees may be paid online, and a constantly updated, full membership directory is available to EBA members.

Please visit www.eba-net.org.

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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], 42 Energy L.J. [page number] Online (2021), [link to report]. Included in the full electronic version of the Energy Law Journal, Volume 42, No. 1, are the following committee reports:

Compliance and Enforcement

Electricity

Gas, Oil, and Liquids

State Commission Practice

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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.

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2004	Charles B. Curtis
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2001	Congressman John D. Dingell

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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.

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2016	Robert S. Fleishman
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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.

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2011	Ben Stone
2010	James Van Nostrand

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Jason F. Leif Chapter Service Award

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.

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

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2005-2019	Robert Fleishman

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, 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, 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

Spring 2021 is a season of big ideas. The Biden administration has announced a $2 trillion infrastructure plan that includes investment in transmission and electric vehicle charging infrastructure. FERC is pursuing transmission rate incentives and issued a policy statement encouraging organized market operators to propose ways to incorporate state-determined carbon prices in wholesale market prices. States and large corporations alike are setting carbon reduction or carbon neutrality goals to be achieved within the next ten to twenty years. And after one of the most severe threats ever to the electric grid in Texas and parts of the Midwest from Winter Storm Uri, the benefits and drawbacks of capacity markets are once again at the forefront of policy discussion.

The *Energy Law Journal* has always been an incubator for big ideas and this issue is no different. In these pages, you will find articles such as "*Is the Utility Transmission Syndicate Forever?*" by Ari Peskoe, which takes a look at whether FERC's open access regime has gone far enough to protect customers against the monopoly power of transmission owners — a critical question as the industry considers what kinds of incentives are necessary and appropriate to spur grid development. Likewise, "*MOPR Madness*" is a timely article in which Joshua Macey and Robert Ward argue that the minimum offer price rules employed in several regional transmission organization tariffs to discipline capacity markets have serious flaws. Each of the articles in this issue provides in-depth review and analysis of important issues facing energy practitioners today.

I am particularly grateful to the *Journal* leadership and volunteers for their tireless efforts during this past year, despite the many challenges posed by the pandemic. Editor-in-Chief Harvey Reiter, Executive Editor Caileen Gamache, and Administrative Editor Nicholas Cicale have demonstrated utmost dedication to ensuring that the *Journal* continues to offer the highest caliber, thought-provoking content. They have been supported by the tireless efforts of numerous volunteer editors and student editors from the University of Tulsa College of Law, as well as Professor Robert Butkin as Faculty Advisor to our student editors. I thank everyone for all their hard work!

Sincerely,
/s/ *Jane E. Rueger*
Jane E. Rueger
President, Energy Bar Association

EDITOR–IN–CHIEF'S PAGE

And I thought the six months leading up to the publication of the *Journal* last November were tumultuous. Since then we've witnessed the reported death toll from COVID-19 more than double, police officer Derek Chauvin's conviction for the murder of George Floyd, a pepper spray assault by Windsor, Virginia police officers on Army Lt. Caron Nazario – unarmed and in uniform and an apparent victim of "driving while black," widespread power outages in Texas with huge regulatory and market consequences – and, unforgettably, an insurrection at the Capitol by a mob of supporters of the former President. My late father, a Holocaust survivor from Poland, remarked to me years ago that the most amazing sight to him was an Inauguration Day when the incumbent president who had lost the election would attend, shake hands with the winner, and then just walk off the stage. That did not happen this year. Instead, as Senate Minority Leader Mitch McConnell recounted at the conclusion of President Trump's second impeachment trial, the attack on our democratic institutions was instigated by the former President himself:

> January 6th was a disgrace. American citizens attacked their own government. They used terrorism to try to stop a specific piece of democratic business they did not like. Fellow Americans beat and bloodied our own police. They stormed the Senate floor. They tried to hunt down the Speaker of the House. They built a gallows and chanted about murdering the Vice President.
>
> They did this because they had been fed wild falsehoods by the most powerful man on Earth — because he was angry he'd lost an election.
>
> ***
>
> This was an intensifying crescendo of conspiracy theories, orchestrated by an outgoing president who seemed determined to either overturn the voters' decision or else torch our institutions on the way out.

While former President Trump plainly had the largest megaphone, he did not create, but simply amplified and normalized the preexisting voices of racism, religious bigotry, and xenophobia. That the insurrection was led not merely by disappointed voters, but white supremacists, was clear from the Capitol Police Inspector General's post-January 6th report. It found that "Stop the Steal" – the name popularly given to the rioters' rallying cry – had the "propensity to attract white supremacists, militia members, and others who actively promote violence."

The link between hate speech and violent conduct is, unfortunately, unmistakable. A recent study by the Anti-Defamation League (ADL) found a near doubling of white supremacist propaganda distribution from 2019 to 2020. The spread of this literature, notes Oren Segal of ADL's Center on Extremism, "helps to bolster recruitment efforts and spreads fear by targeting specific groups, including the Jewish, Black, Muslim and LGBTQ+ communities, as well as non-white immigrants." And we have seen the violence. Attacks on black churches, synagogues, mosques, and LGBTQ individuals have been an all too common occurrence in recent years.

Asian Americans have been among the hardest-hit targets. A recent study conducted for the World Health Organization found that racist and anti-Asian hashtags soared, and have not leveled off since the former President first tweeted "Chinese virus" in March 2020 to describe COVID-19. It is unfortunately no coincidence that the rise in anti-Asian hate speech has been followed by a rise in assaults on Asian Americans and Pacific Islanders. As President Biden stated at his first press conference, "words have consequences." Asian Americans and Pacific Islanders, he noted, have "been verbally assaulted, physically assaulted, killed. It's been a year of living in fear for their lives." "That has to change, because our silence is complicity," he said. "We have to speak out. We have to act."[1]

Why am I writing about all this in the *Energy Law Journal*? Because I'm hoping that *we* will speak out and that *we* will act. The EBA can be rightly proud of its diversity policy. But while we have done much to diversify both the membership and leadership of the energy bar, a vibrant and diverse bar depends, ultimately, on a larger society in which bona fide opportunities for education and economic advancement aren't dependent on one's nationality, sexual orientation, race, or religion.

Many of you may already be members of the nearly 300 firms that have joined the Law Firm Antiracism Alliance – https://www.lawfirmantiracismalliance.org/lfaacharter/alliance-firms. LFAA participation is open to members of any law firm, small, large, or in between. LFAA has a number of working groups addressing the broader issue of societal racism. There are working groups looking at housing, education, gun violence, health care, environmental justice, etc. (In the interest of full disclosure I am co-chair of the Immigration Working Group). If your firm is already a member, consider joining one of the working groups. If the firm you work for or with is not already a member, consider urging it to join.

On the related issues of environmental and energy justice, I would also call to your attention the Department of Energy's newly created position of Deputy Director for Energy Justice. The first person to hold the position, law professor Shalanda Baker, will have responsibility for implementing President Biden's January 27, 2021 Executive Order creating the Justice40 initiative, which will involve consultation with disadvantaged communities about directing federal energy-related investments into those communities.

No Editor-in-Chief's page, of course, would fail to talk about the *Journal* itself. As outgoing EBA President Rueger notes in her President's Message, you'll find an interesting array of articles in this edition.

Four of the five articles touch on various aspects of market power and its regulation. Two articles address whether FERC is overstating market power concerns. In *MOPR Madness*, Josh Macey and Robert Ward explore the question whether the minimum offer price rules that FERC has approved over the last decade are chasing an imaginary (or at least overblown) monopsony power threat to capacity markets posed by buyers and, in the process, are doing more harm than good. John R. Morris, Jéssica Dutra & Tristan Snow Cobb also argue in their article that FERC may be overestimating market power – in this case seller market power – under its current delivered price tests used to evaluate mergers.

The two other market power-themed articles express the opposite concern – that FERC's policies do not offer strong enough medicine to address serious market power concerns. Ari Peskoe recounts the history of FERC's open access policies and their salutary effect, but warns in *Is the Utility Transmission Syndicate Forever?* that FERC's policies still enable incumbent transmission owners to maintain unearned monopolies. Daniel Arthur and Michael Tolleth express a similar concern in their piece – that current FERC policies governing oil pipeline regulation fail to prevent the exercise of pipeline market power, a failure that is resulting in the underdevelopment of oil pipeline capacity.

1. As of this writing, the U.S. House and Senate had both passed versions of the COVID-19 Hate Crimes Act (S-937 and H.R. 6721), legislation that would authorize the Attorney General to review COVID-19 hate crimes against Asian Americans and to provide guidance to state and local law enforcement agencies to facilitate online reporting of such incidents.

Scott Gaille is to writing for the *Journal* what Alex Baldwin is to hosting Saturday Night Live. His seventh article for the *Journal* is another wonderful example of practical scholarship, in this case a lesson in tsouris[2]-avoidance when negotiating construction and service agreements. The time spent negotiating enumerated adjustment clauses up front, he argues, can pay off for both parties in substantial reductions in litigation risk.

This edition also includes reviews of two interesting books. Ken Barry offers his observations on Bill Gates's recent book on combating climate change. And Josh Macey earns a special distinction with his review of Scott Hempling's book on electric mergers: Professor Macey becomes the first person in the *Journal*'s history to have authored both an article and a book review in the same edition of the *Journal*.

This edition of the *Journal* also marks a bittersweet occasion for me, Kat Gamache and my predecessor, Bob Fleishman. All of us have worked closely for years with Tulsa law professor Robert Butkin, the faculty advisor to the students serving on the *Energy Law Journal*. After many years of stellar service to the law school and to the *Journal*, Professor Butkin is retiring. He leaves an enviable legacy, both as a mentor to a generation of students and as a beloved teacher. And he is responsible for many aspects of the *Journal*'s student operation that we take for granted – the yearly workshop for incoming student members of the *Journal* that helps familiarize them with the field of energy law, the requirement that student members of the *Journal* complete a course in Administrative Law, and his efforts to secure internships for students that will prepare them for a career in energy law.

While we will miss his presence in the day-to-day operation of the *Journal*, his retirement is not the end of our friendship and we will continue to count on his sage advice. We are also fortunate that the law school has appointed a worthy successor to take Professor Butkin's place. Professor Warigia Bowman will bring a passion for teaching and for the welfare of her students to the task and we look forward to working with her in the years to come.

Finally, I must offer special thanks to our peer review editors and student editors for their hard work producing another *Journal* edition during a pandemic. Student Editor-in-Chief Jackson Bowker and his editorial board have done a remarkable job under trying circumstances. I cannot adequately express my appreciation for their efforts. And I would be remiss if I did not also point out that the *Journal*'s authors uniformly expressed their appreciation for the peer review and student editors' work as well.

Harvey L. Reiter
Potomac, MD May 2021

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2. "Tsouris" (Yiddish) has been defined as "Troubles, woes, worries, suffering." LEO ROSTEN, THE NEW JOYS OF YIDDISH (Lawrence Bush ed., rev. ed. 2003) (1968). Or, in the context of Scott Gaille's article: "You mean they're suing us? Couldn't we have avoided this tsouris by writing a clearer contract?"

IN MEMORIAM: EDWARD J. GRENIER, JR.

Edward (Ed) J. Grenier, Jr., a longtime practitioner before the Federal Energy Regulatory Commission and former President and Board Member of the Energy Bar Association, passed away on April 7, 2021. Ed was a leader in developing the industrial energy practice at FERC. He represented, for many years, the Process Gas Consumers Group as well as a broad cross section of US industry and other energy clients before FERC.

Born in New York, Ed graduated from Manhattan College, *summa cum laude*, in 1954. He served as a second and then first lieutenant in the U.S. Air Force from 1954 to 1956, and earned his Bachelor of Laws degree, *magna cum laude*, from Harvard Law School in 1959. After graduation, he served as law clerk to the Honorable E. Barrett Prettyman, Chief Judge of the U.S. Court of Appeals for the D.C. Circuit, in 1959-1960, and then joined the law firm of Covington & Burling as an associate. In 1969, he joined the Washington office of Sutherland, Asbill & Brennan (now Eversheds Sutherland (US) LLP), where he practiced energy law and led the firm's Energy Group until his retirement in 2001.

Ed established the energy practice at Sutherland in 1971. His practice initially focused on representing large industrial consumers of natural gas in the curtailment proceedings in the 1970s. He played a lead role in developing FERC's national policy on allocating natural gas among customers based on end use during energy shortages. Ed later expanded the firm's energy practice into other areas, including representing a major natural gas pipeline before FERC. In the mid-1970s, he served as lead counsel for the prevailing applicant in one of the largest energy cases before FERC involving the construction of the Alaska Natural Gas Transportation System to deliver natural gas from Alaska to the lower 48 states. Toward the end of the 1970s, he was instrumental in forming the Process Gas Consumers Group, a broad consortium of large consumers of natural gas used in industrial processing operations, including manufacturers of automobiles, iron and steel, aluminum, glass, and many others. Ed led the representation of PGC in FERC and appellate proceedings involving interstate pipeline services and the supply and price of natural gas until his retirement in 2001.

Ed served as President of the Energy Bar Association, President of the Prettyman-Leventhal American Inn of Court, and as a member of the Board of Directors of the Bar Association of the District of Columbia. He was also active in the American Bar Association and was chairman of the Association's Administrative Law and Regulatory Practice Section as well as a member of the Association's House of Delegates.

Ed was known for his gentlemanly demeanor and was a friend to many in the energy bar. During his 30 years at Sutherland, he mentored many younger lawyers who went on to become leaders in the energy field, continuing his legacy. He was also active in the community, serving as Chair of the Board of Trustees of the Connelly School of the Holy Child from 1978 to 1985, as a member of the Board of Directors of D.C. Recording for the Blind from 1977 to 1989, as Chair of the Lighthouse Board of Trustees for several years, and as President of the Thomas More Society of America.

Ed is survived by his wife Pat and his children Edward Jr., Peter, and Tori. He will be greatly missed by his family and all who knew him.

IN MEMORIAM: KENNETH WILLIAMS

Many older members of the Energy Bar Association remember Ken Williams with tremendous respect and fondness. He is one of the "greats" in the history of the Federal Power Commission (FPC) and the Federal Energy Regulatory Commission (FERC). Ken became Director of Pipeline and Producer Regulation at the FERC not long after it was created in 1977 and was deeply involved in the implementation of the Natural Gas Policy Act of 1978 (NGPA). Prior to the NGPA's enactment, the gas industry in the US had gone through periods of gas curtailments in the interstate markets even though there were plentiful gas supplies in the intrastate markets in the production states such as Texas. Ken was a veteran of gas allocation battles decided by the FPC.

Following the enactment of the NGPA, Ken not only worked to address some continuing gas shortage issues but also supported the Commissioners in opening up gas markets to prevent shortages in the future. These efforts led to the more market-oriented regulatory schemes in the 1980s and 1990s which form the basis for FERC's regulation of the gas pipeline industry today.

To many energy lawyers who started their careers at the FERC, Ken was our first client. He was also our mentor who taught us about the workings of the natural gas industry and its many cross factions that produced benefits to the American public. He was a "hands-off" client who gave his attorneys wide berth to reach the results desired by him for the Commission.

After a 4-year stint in the U.S. Navy, Ken joined the FPC in 1957 as an economist. He rose through the ranks in the Bureau of Natural Gas, first in the Pipeline Division and then in the Pipeline and Producer Rate Division, being involved in many of the area and nationwide producer rate proceedings that were spawned by the Supreme Court's decision in *Phillips Petroleum Co. v Wisconsin* in 1954. He was also involved in many gas pipeline rate proceedings throughout his career.

When the FERC was created in 1977, Ken became Deputy Director of the Office of Pipeline and Producer Regulation (OPPR). In 1979, he become Director of OPPR, a position he held until he retired from FERC in 1986. Ken was the first director of a technical office chosen from among the ranks of the Commission's professional staff. Previous directors were political appointees.

Ken was a trusted advisor to many of the FPC and FERC commissioners, particularly during the energy crises in the 1970s and during the shift away from traditional regulation in the 1980s, especially over natural gas production. During his tenure with the FERC, Ken was delegated authority by Commission regulation and had to decide many petitions for "staff adjustments" to the FERC's regulations. While at the FERC, many Energy Bar Association attorneys wrote and defended on appeal the staff adjustments rendered by Ken in the areas of priorities in gas curtailment plans and producer price categories. Ken was involved in helping the Commission wade through the knotty issue whether area rate clauses in natural gas producer sales agreements were triggered by the higher producer prices authorized in the NGPA. He was also involved in the issue of the pricing of the pipelines' own gas production in light of the enactment of the NGPA, an issue that was ultimately decided by the Supreme Court in *Public Service Commission of the State of New York v Mid-Louisiana Gas Company* in 1986.

Upon retiring from FERC in 1986, Ken was one of the founding members of what is now Brown, Williams, Moorhead & Quinn, an energy consulting firm operating primarily in the pipeline rate area. Ken fully retired from his consulting firm in 2007.

Ken was a graduate of Western Kentucky State College (now Western Kentucky University). He also did graduate work in economics at Cornell University.

Ken passed away on December 31, 2020, surrounded by his family and is survived by Pat, his wife, their three sons, and many grandchildren and great-grandchildren. Ken and his family were long-time residents of Silver Spring, Maryland. He will be missed.

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IS THE UTILITY TRANSMISSION SYNDICATE FOREVER?

*Ari Peskoe**

Synopsis: Approved by states to act as local monopolists, investor-owned utilities (IOUs) promptly extended their reach by building transmission lines to neighboring utility systems. Transmission links transformed IOUs from state-sanctioned service providers to interstate system operators and wholesalers. With overriding control over transmission in their monopoly service territories, IOUs exploited nearby non-profit utilities and regionalized their dominance through collusive agreements with each other that obstructed competition and cartelized infrastructure development. From 1996 to 2011, FERC issued four orders that aimed to wrest the nation's high-voltage electric delivery systems from IOU control and open interstate power systems to competition.[1] FERC's agenda has since stalled. Further action is needed to disconnect transmission expansion from IOUs' state-granted service territories.

In this article, I explore the history of FERC's oversight of IOU transmission dominance. I start at the beginning, prior to FERC's existence, when states granted IOUs local service territories and provided them with dependable revenues through state-run ratemaking processes. With these "unearned advantages,"[2] IOUs built transmission infrastructure that extended their dominance to interstate power systems. In response to the financial collapse of the corporate structures that fueled IOU growth, Congress charged FERC with policing IOUs' anti-competitive practices while also encouraging their coordination. For decades, FERC generally tolerated IOU-to-IOU transmission coordination agreements that excluded competitors and discriminated against customers, believing that efficiencies gained through voluntary IOU arrangements were impossible to achieve through open competition. Once technological and regulatory changes exposed opportunities for the development of competitive wholesale power markets, FERC

* Ari Peskoe is the Director of the Electricity Law Initiative at Harvard Law School. I greatly appreciate the generosity of Matthew Christensen, Miles Farmer, Rob Gramlich, Joshua Macey, and Burcin Unel, all of whom read drafts and provided helpful feedback. I also thank Sharon Jacobs, Shelley Welton, and James Coleman for organizing the Early Career Energy Scholars Workshop and all attendees at that workshop for reading an early draft. I am also grateful for Nathan Lobel's careful review and for Howard Peskoe's meticulous proofreading.

1. In this article, I will be discussing orders issued by FERC's predecessor, the Federal Power Commission. For simplicity, I will use the term FERC throughout, even when referring to FPC orders issued prior to FERC's creation in 1977.

2. I adapt this phrase from SCOTT HEMPLING, REGULATING MERGERS AND ACQUISITIONS OF U.S. ELECTRIC UTILITIES: INDUSTRY CONCENTRATION AND CORPORATE COMPLICATION 157 (2020). As he explains:

> A decades-long, government-protected provider of monopoly services has advantages when providing competitive services. Those advantages come from four main sources: customer behavior, the utility's internal characteristics, the utility's own actions and simple luck. Because these advantages arise not from risk-taking or skill, but from the utility's historic status, they are unearned.

While Hempling describes IOUs' modern-day advantages in competitive markets, I use his phrase as a shorthand to explain how IOUs were able to control transmission networks decades ago.

changed its approach and sought to restrain IOUs' transmission dominance in order to facilitate entry into the industry.

This dramatic shift — from emphasizing voluntary IOU coordination under section 202 of the Federal Power Act (FPA) to policing IOU conduct under section 206 — was predicated on FERC's decision to reclassify long-standing IOU practices as "unduly discriminatory" under the FPA. FERC concluded that anti-competitive IOU behavior was systemic and fashioned remedies, for the first time, on an industry-wide basis. FERC's reforms to transmission operations and planning have been guided by two key principles: comparability and transparency. FERC's orders require IOUs to provide their customers and their own power marketing operations with comparable transmission service, and, when planning system expansion, to consider the needs of customers on a comparable basis with their own goals. FERC has also attempted to liberate transmission information from utility control by compelling IOUs to share operational and planning data and models. Structural reforms that separate IOUs from transmission operations and planning by placing an "independent" entity between IOUs and decisionmaking aim to improve the effectiveness of FERC's comparability and transparency requirements and further neutralize IOUs' incentives to restrain competition.

IOUs often resisted these reforms, responding to FERC's orders with proposals that failed to meet FERC's minimum standards. I focus on IOUs' responses to FERC's transmission planning directives and in particular their extensive efforts to evade FERC's mandate that new projects be subject to competitive development processes. FERC has rejected the premise that century-old state laws that effectively provide IOUs with exclusive service territories grant these companies perpetual rights to develop the nation's interstate electric delivery systems. While FERC has removed certain barriers to entry for non-IOU developers, it has yet to foster a development process that stimulates significant non-IOU projects. Moreover, planning processes have not spurred adoption of new technologies that can obviate the need for local transmission projects or led to the sort of large-scale transmission projects that could efficiently integrate zero-emission renewable resources. While scholars and practitioners have focused on transmission siting challenges to unlocking renewables, I focus on the transmission planning process that selects transmission projects for development through cost-of-service rates. I offer a perspective on IOU transmission ownership that suggests the status quo is incompatible with development of large-scale interregional connections designed to integrate new wind and solar and deployment of advanced technologies that can substitute for local transmission expansion.

IOUs are at the heart of the problem. They are driven to maintain the status quo, in part by capitalizing on FERC's rules that allow them to build projects within their state-granted territories without competitive pressures and on the backs of their captive retail ratepayers. This local focus is at odds with FERC's decades-long push for regionalization, and the IOUs' defensive approach to transmission development has no place in a technologically dynamic industry. Apart from concerns about the topology and technologies of our interstate networks, FERC's duty to combat anticompetitive behavior compels it to continue chipping away at IOU transmission dominance. These entitlement-claiming century-old companies are frustrating FERC's efforts to bring competitive discipline to transmission development.

FERC should reclaim its transmission agenda. Rather than intervene directly in IOU-controlled planning processes, I propose that FERC should induce IOUs to accept third-party controlled planning. FERC has exclusive authority to determine whether transmission spending is prudent, and in making that determination, it should consider how transmission investment is planned. FERC should issue a new policy on prudence that subjects IOU-controlled spending to scrutiny while maintaining the current presumption that independently planned transmission is prudent. My hope is that under this new approach to transmission rates, IOUs will voluntarily cede control of planning. If IOUs fail to do so, FERC retains broad authority under section 206 to police anti-competitive IOU behavior and should act decisively to separate transmission planning from IOU control.

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I. THE LEGAL FRAMEWORK FOR FERC'S TRANSMISSION OVERSIGHT

Congress passed the Public Utility Act of 1935 "in the context of, and in response to, great concentrations of economic and even political power vested in" interstate utility holding companies.[3] The Act, according to the Supreme Court, "had two primary and related purposes: to curb abusive practices of public utility companies by bringing them under effective control, and to provide effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce."[4] Part I of the Act charged the Securities and Exchange Commission with addressing "economic evils resulting from uncoordinated and unintegrated public utility holding company systems"[5] (known as trusts) by controlling their corporate structures.[6] Part II tasked FERC with regulating the interstate sales and service provided by the power trusts' local operating companies (the IOUs), and in particular neutralizing the privileges provided to them by states and abused by the power trusts.

The ascendancy of the power trusts followed states' decisions in the early twentieth century to grant IOUs market power. Public utility laws, which arose in-part "out of the interests of incumbent [IOUs] in protecting their industry from competition,"[7] empowered state regulators to control entry into the nascent electricity industry.[8] In general, regulators concluded that the dominant local provider should enjoy monopoly privileges because allowing firms to provide competing service would harm consumers who benefited from a single company capturing economies of scale. By preventing non-utility investment, regulators effectively sanctioned exclusive utility service territories that enabled IOUs to dominate the rapidly growing power industry.[9]

3. Gulf States Utilities Co. v. FPC, 411 U.S. 747, 758 (1973); North Am. Co. v. SEC, 327 U.S. 686, 703 n.13 (1946) (quoting Report of the National Power Policy Committee on Public-Utility Holding Companies, H.Doc. 137, 74th Cong., 1st Sess., p. 5) [hereinafter NPPC Report] (power trusts were motivated "by a desire for size and the power inherent in size"); *Re Dairyland Co-Op*, 37 F.P.C. 12, at p. 15 (1967) ("The purpose of that legislation was most clear: it was designed to prevent the notorious investment and profit abuses which had developed in the industry under the domination of the holding companies.").

4. *Gulf States Utilities Co.*, 411 U.S. at 758; Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design, Notice of Proposed Rulemaking, 67 Fed. Reg. 55,452 at P 100 (Aug. 29, 2002) [hereinafter SMD NOPR] ("The primary purposes of the Federal Power Act are to curb abusive practices by public utilities and to protect customers from excessive rates and charges.").

5. *North Am. Co.*, 327 U.S. at 706 (1946); *see also id.* at 703 n.13 (quoting NPPC Report, *supra* note 3) (summarizing federal investigations that revealed that the growth of utility holding companies was often "attained with the great waste and disregard of public benefit" and was "actuated primarily by a desire for size and the power inherent in size").

6. *Id*. at 706.

7. Lynne Kiesling & Adrian T. Moore, *Movin' Juice: Making Electricity Transmission More Competitive*, REASON FOUND. (Sept. 1, 2003), https://reason.org/wp-content/uploads/2003/09/40989a8a7676e2409eb4951655cc0dcd.pdf (citing Vernon Smith, *Regulatory Reform in the Electric Power Industry*, 1 REGULATION 33 (1996) and Gregg Jarrell, *The Demand for State Regulation of the Electric Utility Industry*, J. L. & ECON., at 269-95 (Oct. 1978)).

8. *See* William K. Jones, *Origins of the Certificate of Public Convenience and Necessity: Developments in the States, 1870–1920*, 79 COLUMBIA L. REV. 426 (1979).

9. Initially, exclusivity was governed by the IOUs' franchises granted by the state or municipalities, and, in many states, franchises were legally required to be non-exclusive. Paul L. Joskow, *Mixing Regulatory and Antitrust Policies in the Electric Power Industry: The Price Squeeze and Retail Market Competition*, ANTITRUST

IOUs financed system expansion through state-regulated rates that tied IOU profits to the amount of money they invested in physical assets, such as power plants and transmission lines.[10] The combination of exclusive service territories and administrative ratemaking minimized investment risks, allowing IOUs to cheaply finance new infrastructure. The states' regulatory model was designed to maximize local service. Locally based IOUs with local service territories collected revenue from local ratepayers to build local infrastructure needed to meet growing local demand.

But with power trusts pulling the strings, IOUs became ensnared in multi-state holding companies controlled by out-of-state investors. The corporate groupings were tied more to "promoters' dreams of far-flung power and bankers' schemes for security profits" than consumers' needs or economically efficient operations.[11] State regulators faced practical and legal barriers to reining in the power trusts and controlling the interstate expansion and transactions of the entities that they had nurtured.[12]

In the 1935 Act, Congress sought to remedy the power trusts' inefficient management by subjecting their operating companies to federal oversight and tasking FERC with encouraging efficient coordination.[13] The industry and Congress un-

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AND REGULATION: ESSAYS IN MEMORY OF JOHN J. MCGOWAN 178–79 (1985). Litigated cases from the 1930s highlight that IOUs in many states had non-exclusive franchises. *See, e.g.,* Tenn. Electric Power Co. et al. v. Tenn. Valley Auth. et al., 306 U.S. 118, 138 (1939). Eventually, nearly all states passed laws that established exclusive territories for IOUs. David C. Hjelmfelt, *Exclusive Service Territories, Power Pooling and Electric Utility Regulations*, 38 FED. B.J. 21 n.1 (1979) (stating that forty states had established utility service territories by statute).

10. William Boyd, *Public Utility and the Low-Carbon Future*, 61 UCLA L. REV. 1614, 1643 (2014).

11. *North Am. Co.*, 327 U.S. at 703 n.13 (quoting NPPC Report, *supra* note 3) (trusts did "no more than pay lip service to the principle of building up a system as an integrated and economic whole . . . Instead, they have too frequently given us massive, over-capitalized organizations of ever-increasing complexity and steadily diminishing coordination and efficiency."); *id.* at 701 ("Public utility holding companies are thereby able to build their gas and electric utility systems, often gerrymandered in such ways as to bear no relation to economy of operation or to effective regulation."); Salt River Project Agric. Improv. & Power Dist. v. FPC, 391 F.2d 470, 475 (D.C. Cir. 1967) (noting that the Federal Trade Commission (FTC) conducted a seven-year investigation and "chronicled at length the venal conditions and iniquitous practices" of the holding companies and quoting from the FTC report that "fraud, deceit, misrepresentation, dishonesty, breach of trust, and oppression are the only suitable terms to apply if one seeks to form an ethical judgment on many practices" of the holding companies (quoting Summary Report of the FTC to the Senate, Document 92, Part 73-A, 70th Cong., 1st Sess., p. 63 (1935)); Robert H. Tucker, *The Public Utility Act of 1935: Its Background and Significance*, 4 SOUTHERN ECON. J. 423, 425 ("Arbitrary write-ups of the value of capital assets were wide-spread, and fantastic overheads were capitalized to balance excessive security issues and create seeming surpluses and reserves."). *But see* Thomas P. Hughes, NETWORKS OF POWER: ELECTRIFICATION IN WESTERN SOCIETY, 1880–1930 393 (1993) ("Contrary to popular opinion, the origins and development of several leading electric-utility holding companies are to be found rooted more deeply in technology and management history than in finance.").

12. Jersey Central Power & Light v. FPC, 319 U.S. 61, 67 n.7 (1943) (quoting S. Rep. No. 621, 74th Cong., 1st Sess., p. 17) ("Other features of this interstate utility business are equally immune from State control either legally or practically."); Tucker, *supra* note 11, at 423 (explaining why state regulation proved ineffective at controlling power trusts' abuses); *Section 11(B) of the Holding Company Act: Fifteen Years in Retrospect*, 59 YALE L.J. 1088, 1093 (explaining that "[s]tate regulation proved incapable of dealing with the [] abuses" by interstate holding companies).

13. *North Am. Co.*, 327 U.S. at 703 n.13; *Jersey Central Power & Light*, 319 U.S. at 68 n.7 (quoting S. Rep. No. 621, 74th Cong., 1st Sess., p. 17) ("The new part 2 of the Federal Water Power Act seeks to bring about

derstood that coordinating operations through interconnected transmission networks was more efficient than each IOU operating as an island. While coordination among IOUs brought clear benefits, agreements between IOUs and non-profit utilities (owned by rural cooperatives and municipalities) often reflected the power imbalance between the parties.[14] The so-called transmission-dependent utilities[15] (TDUs) were both IOUs' competitors (in limited respects) and captive wholesale customers that relied on interstate FERC-regulated IOU service to meet the needs of their local distribution customers.[16]

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the regional coordination of the operating facilities of the interstate utilities along the same lines within which the financial and managerial control is limited by title I of the bill.").

14. IOUs also used their control of transmission within their state-granted territories to dominate TDUs within their boundaries or adjacent to their territories. The American Public Power Association summarized in a Supreme Court brief that IOUs:

- "have been at war for many years with the municipalities in their areas which have been struggling to establish publicly owned systems for themselves."
- "frequently refused to interconnect facilities for any purpose."
- "refused to sell bulk power at wholesale to a municipality . . . The reason is too often anticompetitive."
- "frequently wheel power for one another but . . . refuse to wheel power for consumer-owned systems. The purpose is to choke off competition."
- "use the leverage of their monopolistic position to insert 'requirements' provisions in wholesale contracts with municipalities and cooperatives. These anticompetitive restriction, curtail a buyer's future options."

APPA summed up that these and other activities, "viewed in totality, with the realization that the fundamental purpose of the activities is to prevent or stifle competition, [must be seen] as blatantly anticompetitive." Brief of the American Public Power Association (APPA), Supreme Court Docket No. 71-991, Otter Tail Power Co. v. U.S., Sep. 25, 1972. *See also Hearings on the Competitive Aspects of the Energy Industry Before the Subcomm. on Antitrust and Monopoly of the Senate Comm. on the Judiciary,* 91st Cong., 2d Sess., at pp. 378–386, 418–425 [hereinafter Senate Hearings on Antitrust and Monopoly] (APPA manager describing these and other issues, including "exclusion from pooling"); *id.* at 472–476 (Secretary of the Northern California Power Agency detailing "Pacific Gas & Electric Co.'s almost total effort to effectively block small municipalities from obtaining sources of low-cost electric energy" and alleging that the IOU is "using every possible means to control the wholesale power market in northern California in particular, and elsewhere, so that the only source of bulk power available to our cities will be to purchase it from PG&E."); *id.* at 628 (counsel of the National Rural Electric Cooperative Association testifying that IOU companies "can place the cooperatives under intense economic pressures, pirate their consumers, and invade the[ir] territories . . . Some companies have . . . abused their dominant industry position in what has been an apparent effort to drive the cooperatives out of business, and, thereby achieve an even greater degree of dominance. Other companies have engaged in similar territorial and customer pirating tactics . . .").

15. *See* Comments of the Transmission Dependent Utility Systems, FERC Docket No. AD12-9 (Mar. 29, 2012) ("While some of the TDU Systems own substantial transmission facilities, all of them rely on the transmission systems of neighboring investor-owned public utility transmission owners regulated by the Commission in order to move their power supplies to their member distribution cooperatives' loads.").

16. Rival utilities may have competed to serve an industrial customers considering building new facilities or to provide service to "fringe" customers located on the edge of defined service territories. At the bulk power level, utilities competed to serve smaller utilities that relied on transmitted power to serve their customers. FERC, Office of Electric Power Regulation, *Power Pooling in the United States*, 63–65 (Dec. 1981) [hereinafter Power Pooling in the U.S.] (outlining four distinct types of retail competition: franchise, yardstick, fringe area, serving new large loads; and also describing wholesale competition); PAUL L. JOSKOW AND RICHARD SCHMALENSEE, MARKET FOR POWER: AN ANALYSIS OF UTILITY DEREGULATION 20–23 (1983) (describing fringe area, franchise, and yardstick competition and competition to serve new industrial loads as well as for wholesale bulk power supplies).

Congress required FERC to grapple with this tradeoff between efficiency-enhancing voluntary IOU coordination and anti-competitive IOU behavior toward their customers and competitors.[17] Section 202 of the FPA directs regulators to "promote and encourage voluntary interconnection and coordination" among utilities.[18] It reflects Congress's belief at the time that coordination among the industry's largest private actors, rather than "limited competition"[19] between them, was the best option for improving industry performance.[20] But Congress also tasked FERC with restraining IOU coordination it finds "unjust and unreasonable" or "unduly discriminatory,"[21] broad standards that FERC eventually understood to encompass consideration of anticompetitive IOU behavior.[22]

Congress split FERC's authority to review utility rates and contracts into two sections. Section 205 of the FPA compels IOUs to file all agreements and tariffs for FERC-jurisdictional interstate service and empowers FERC to investigate whether each filing is just and reasonable and not unduly discriminatory.[23] To approve a filing, FERC need not conclude that the agreement or tariff is optimal and must reject the filing only if it finds it inconsistent with the statute's imprecise ratemaking standards.[24] Section 206 instructs FERC to respond to complaints alleging that an agreement or tariff is unjust and unreasonable or unduly discriminatory, and allows it to initiate its own investigations into IOU agreements and tariffs.[25] To force an IOU to modify an agreement or tariff, FERC must meet a

17. *See, e.g.,* FERC, Inquiry Concerning Alternative Power Pooling Institutions Under the Federal Power Act, 59 Fed. Reg. 54,851, 54,852 (Nov. 2, 1994) ("[W]e must consider whether we are appropriately balancing our dual objectives of promoting coordination and competition.").

18. 16 U.S.C. § 824a(a).

19. Gulf States Utilities Co. v. FPC, 411 U.S. 747, 759 (1973).

20. Central Iowa v. FERC, 606 F.2d 1156, 1162 (D.C. Cir. 1979) ("Congress has decided, as a matter of general policy, that power pooling arrangements, rather than unrestrained competition between electric facilities, are in the public interest."); *Id.* at 1163 ("In enacting [] section [202(a)], Congress was 'confident that enlightened self-interest will lead the utilities to cooperate . . . in bringing about the economies which can alone be secured through . . . planned coordination.'" (quoting S. Rep. No. 621, 74th Cong., 1st Sess. 49 (1935))).

21. The Supreme Court has understood that FERC's promotion and encouragement is constrained by an obligation to "consider . . . anticompetitive effects" of coordination. *Gulf Utilities Co*., 411 U.S. at 758–59.

22. *Id.*; FPC v. Sierra Pacific Power Co., 350 U.S. 348, 355 ("the purpose of the power given the Commission by s. 206(a) is the protection of the public interest, as distinguished from the private interests of the utilities"); Otter Tail Power Co. v. U.S., 410 U.S. 366, 373 (1973) ("[T]he history of Part II of the Federal Power Act indicates an overriding policy of maintaining competition to the maximum extent possible consistent with the public interest."); *see also* Joel Eisen, *FERC's Expansive Authority to Transform the Electric Grid*, 49 U.C. DAVIS L. REV. 1783, 1799–1802 (summarizing the history of undue discrimination).

23. Section 205 prohibits an IOU from making or granting any undue preference or advantage to any person or subjecting any person to any undue prejudice or disadvantage. *See* 16 U.S.C. § 824d. It does not include the phrase "unduly discriminatory." That term is in section 206. For simplicity, I use the term "unduly discriminatory" throughout as shorthand and treat the standards in 205 and 206 as if they are identical.

24. Morgan Stanley Capital Grp. Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty., 554 U.S. 527, 532 (2008) ("'just and reasonable' is obviously incapable of precise judicial definition") (citations omitted); Wis. Pub. Power v. FERC, 493 F.3d 239, 260 (D.C. Cir. 2007) (a party opposing FERC's section 205 finding must "show that the Commission's choices are unreasonable and its chosen line of demarcation is not within a zone of reasonableness as distinct from the question of whether the line drawn by the Commission is precisely right") (citation omitted).

25. 16 U.S.C. § 824e.

"dual burden."[26] First, FERC must demonstrate that the existing agreement or tariff fails to meet the FPA's standards.[27] Second, FERC must find that the proposed changes to the tariff or agreement are just and reasonable and not unduly discriminatory.[28]

For decades, FERC routinely approved IOU-to-IOU coordination agreements under section 205 that reinforced IOU dominance, overlooking IOUs' "systemic anticompetitive behavior"[29] that impeded competition in wholesale power. FERC changed course in the mid-1990s. Rather than relying on the "self-interest" of IOUs to coordinate voluntarily in a manner that would benefit consumers,[30] FERC sought to harness competitive wholesale electricity markets to improve the industry's performance. FERC recognized, however, that "the single greatest impediment to competition" is IOUs' "market power through control of transmission."[31] To address this barrier to competition, FERC ordered each IOU to provide its customers and its own power marketing businesses with comparable transmission service. FERC also required IOUs to publish real-time transmission system conditions in order to mitigate IOUs' informational advantages. Alongside these section 206 mandates, FERC developed a market-based rate regime for jurisdictional power sales under section 205 that allowed suppliers to apply for permission to sell power free from FERC's traditional oversight. Together, FERC's Open-Access mandate and approval of market-based rates facilitated the creation of competitive markets for wholesale power.

Both developments are rooted in FERC's authority to define, detect, and address market power.[32] FERC determined that market-based rates are just and reasonable when "neither buyer nor seller has significant market power."[33] Rather than evaluating whether a utility's rates are "sufficient to assure confidence in the

26. FirstEnergy Servs. Co. v. FERC, 758 F.3d 346, 353 (D.C. Cir. 2014).

27. *Id.*

28. *Id.*

29. *See* Transmission Access Policy Group v. FERC, 225 F.3d 667, 684 (D.C. Cir. 2000) (upholding Order No. 888 and summarizing that FERC found "systemic anticompetitive behavior" by IOUs).

30. *See supra* note 20.

31. FERC, Proposed Rule, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities, 60 Fed. Reg. 17,662, 17,664 (Apr. 7, 1995) [hereinafter Order No. 888 NOPR]; FERC, Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities, Recovery of Stranded Costs by Public Utilities, 61 Fed. Reg. 21,540, 21,546 (May 10, 1996) [hereinafter Order No. 888] ("The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive ownership of the facilities."); James E. Meeks, *Concentration in the Electric Power Industry: The Impact of Antitrust Policy*, 72 COLUMBIA L. REV. 64, 87 (1972) ("the monopoly over transmission by vertically integrated systems presents the most serious obstacle to potential competition.").

32. *See, e.g.,* Order No. 697, Market-Based Rates for Wholesale Sales of Electric Energy, Capacity, and Ancillary Service by Public Utilities, 119 F.E.R.C. ¶ 61,295, at P 397 (2007) (summarizing that market-based rate authority is contingent on FERC findings about "whether the seller and its affiliates have transmission market power or whether they can erect other barriers to entry").

33. Tejas Power Corp. v. FERC, 908 F.2d 998, 1004 (D.C. Cir. 1990); *see also* Morgan Stanley Capital Grp Inc. v. Pub. Util. Dist. No. 1 of Snohomish Cty., 554 U.S. 527, 537 (2008); California Ex. Rel. Lockyer v. FERC, 383 F.3d 1006 (9th Cir. 2004); Montana Consumer Counsel v. FERC, 659 F.3d 910 (9th Cir. 2011); FERC Order No. 697, 119 F.E.R.C. ¶ 61,295 (2007).

financial integrity of the enterprise,"[34] as it did under cost-of-service regulation, FERC inquires "whether an individual seller is able to exercise anticompetitive market power"[35] before sanctioning market-based rates under section 205. Step-by-step, as FERC advanced its market-based rate regime, it has consistently emphasized the central importance of exposing and mitigating market power.[36]

Similarly, FERC predicated its Open-Access mandate on its conclusion that transmission-owning IOUs "possess substantial market power [and] as profit maximizing firms, they have and will continue to exercise that market power in order to maintain and increase market share."[37] In response to that finding, FERC changed the focus of its analysis under sections 205 and 206. Historically, FERC considered transmission discrimination on a customer-by-customer basis, and it might find service to be unduly discriminatory if the IOU provided markedly different service to similar transmission customers.[38] With its new focus on IOU market power, FERC compared the service IOUs provided for their own power marketing businesses with the service they provided to third parties.[39] With that understanding of undue discrimination, FERC concluded on a generic basis that IOUs have incentives and abilities to unduly discriminate against their customers and competitors by offering inferior service or planning system expansion based on their own needs and parochial interests.

Transmission dominance is my shorthand for this foundational finding that all IOUs have abilities and incentives to operate and plan transmission for their benefit and to the detriment of their competitors. In FERC's Open-Access orders, IOU transmission dominance overlaps with IOU "market power." FERC concluded that IOU control over transmission allowed them to exclude potential competitors and charge uncompetitive prices, two hallmarks of the exercise of market

34. FPC v. Hope Nat. Gas Co., 320 U.S. 591, 603 (1944).

35. Blumenthal v. FERC, 552 F.3d 875, 882 (D.C. Cir. 2009); *see also Lockyer*, 383 F.3d at 1013.

36. Order No. 2000, Regional Transmission Organizations, 89 F.E.R.C ¶ 61,285, at pg. 190 (1999) (explaining that "the Commission has the primary responsibility to ensure that regional wholesale electricity markets . . . operate without market power" and tasking market operators with identifying and reporting "market power abuses"); 18 C.FR. § 35.34 (requiring RTOs to "provide for objective monitoring . . . to identify . . . market power abuses . . . "); *PJM Interconnection*, 110 F.E.R.C .¶ 61,053, at P 25 (2005) (approving locational marginal pricing (LMP) as the price-setting mechanism in part because LMPs provide "generators *that lack market power* [with] an incentive to submit bids at their marginal costs"); *PJM Interconnection*, 117 F.E.R.C ¶ 61,331, at P 6 (2006) (approving a settlement that resulted in the creation of the PJM capacity auction whose "design features that [] the exercise of market power" and that aimed to "provide fewer incentives for sellers to exercise market power"). FERC has approved numerous market power mitigation measures. *See, e.g.,* Edison Mission Energy v. FERC, 394 F.3d 964 (D.C. Cir. 2005); Wisconsin Public Power v. FERC, 493 F.3d 239 (D.C. Cir. 2007). FERC regularly investigates market power under section 206. *See, e.g., Nevada Power Co., et al.*, 155 F.E.R.C. ¶ 61,249 (2016); *Idaho Power Co.*, 168 F.E.R.C. ¶ 61,156 (2019).

37. Order No. 888 NOPR, *supra* note 31, at 17,665; *see also id.* at 17,664; *Citizens Power & Light Corporation*, 48 F.E.R.C. ¶ 61,210, at p. 61,777 (1989) ("The most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities. Usually, the source of market power is dominant or exclusive ownership of the facilities.").

38. Eisen, *supra* note 22, at 1808.

39. Order No. 888, *supra* note 31, at 21,548 (citing *Am. Elec. Power*, 67 F.E.R.C. ¶ 61,317, at p. 61,489 (1994)); Eisen, *supra* note 22, at 1814–1817.

power.[40] But, as I describe below, its subsequent transmission planning rules do not rest on similar findings about IOU market power. Rather, FERC's section 206 findings are premised on theoretical threats to the justness and reasonableness of rates due to IOUs' abilities to unduly discriminate against non-IOUs in planning system expansion. Because this more expansive notion of IOU transmission dominance persists, FERC has unexercised authority under section 206 to separate IOUs from transmission decisionmaking or take other remedial actions that aim to neutralize IOUs' unearned advantages.[41]

The Open-Access mandate marked two fundamental shifts in how FERC wields its authority. To remedy IOUs' unduly discriminatory transmission service, FERC specified minimum terms and conditions that all regulated transmission owners or operators (also known as providers) must include in their transmission tariffs.[42] This industry-wide mandate was a sharp departure from FERC's prior utility-by-utility approach under section 206. In subsequent orders, FERC required transmission providers to amend their so-called Open-Access Transmission Tariffs (OATTs) to address whatever IOU conduct FERC found to be unjust and unreasonable or unduly discriminatory. These minimum terms and conditions in the OATT, established through rulemakings, set the standard against which FERC evaluates a complaint filed under section 206, a section 205 transmission tariff filing, or a comment in any proceeding about a transmission tariff. FERC's inquiry focuses on whether the transmission provider is complying with the relevant rulemakings,[43] rather than whether the provider's conduct meets some bespoke notion of unjust and unreasonable or unduly discriminatory that a complainant or commenter has crafted for that proceeding.

Alongside its bold shift to aggressively wielding its section 206 authority, FERC transformed how it encourages voluntary coordination under section 202. Its prior approach relied on IOUs developing ad-hoc agreements that could include a range of coordination activities, from merely conferring about certain seasonal activities or long-term planning to jointly operating their interconnected systems

40. In general, market power refers to the ability to charge uncompetitive prices or exclude competition. Hempling, *supra* note 2, at 29 (quoting U.S. v. E.I. du Pont de Nemours & Co., 351 U.S. 377, 391 (1956) and Dept. of Justice and Fed. Trade Comm'n, Horizontal Merger Guidelines § 1.1 (1992, rev. 1997)).

41. *See* South Carolina Pub. Serv. Authority v. FERC, 762 F.3d 41, 57–69 (D.C. Cir. 2014) (upholding Order No. 1000 in part due to the FPA's "broadly stated" authority to remedy anti-competitive practices even where FERC's action is premised on a "theoretical threat" to just and reasonable rates, such as the absence of competition); Transmission Access Policy Grp. v. FERC, 225 F.3d 667, 687 (D.C. Cir. 2000) (holding that the FPA's "ambiguous antidiscrimination provisions . . . giv[e] [FERC] broad authority to remedy unduly discriminatory behavior").

42. Order No. 888, *supra* note 31, at 21,541.

43. *See, e.g., Cent. Power & Light Co., et al.,* 87 F.E.R.C. ¶ 61,001, at p. 61,002 (1999) (rejecting request in a section 205 proceeding that FERC add a provision to the tariff at issue about joint transmission planning because "[i]n Order No. 888-A, the Commission decided not to mandate joint planning"); *Monongahela Power, et al.*, 164 F.E.R.C. ¶ 61,217, at P 31 (2018) (rejecting reforms suggested by market participants in a section 205/206 proceeding because "[t]he PJM Transmission Owners are required only to meet the requirements of Order No. 890, not exceed them."); *TranSource LLC v. PJM Interconnection*, 168 F.E.R.C. 61,119, at P 81 (2019) (rejecting complainants' claim about system impact studies in part because Order No. 890 does not apply to such studies and therefore the "transparency" principle mandated by the order is inapplicable); *GridLiance High Plains*, 174 F.E.R.C. ¶ 61,078 (2021) (rejecting transmission planning proposal as inconsistent with definitions in Orders No. 890 and 1000).

on a minute-to-minute basis.[44] Beginning in the 1990s, FERC endorsed particular types of coordination agreements that would be consistent with its anti-transmission dominance agenda and outlined how it would evaluate joint utility filings under section 205. FERC's guidance encouraged utilities to create new organizations that are "independent" from IOUs themselves and directly regulated by FERC pursuant to sections 205 and 206. By allowing for the creation of these independent entities, FERC aimed to restructure the industry in order to free the nation's bulk power system from IOU control.

FERC's reforms over the past three decades have standardized its approach to policing IOU transmission dominance. To address its generic conclusion that all IOUs have abilities and incentives to unduly discriminate, FERC required all IOUs to file OATTs that contain specified terms and conditions. FERC implements industry-wide reforms by imposing new terms and conditions in OATTs and justifies those reforms by pointing to a systemic problem in operations or planning tied to IOUs' abilities to act anti-competitively. As I explain in the following sections, two principles animate FERC's reforms: transmission providers must 1) provide comparable service to all parties, and 2) publish commercially relevant information. FERC ensures that transmission service meets the FPA's ratemaking standards by enforcing compliance with the OATT.

To appreciate FERC's focus on these comparability and transparency principles, I provide a perspective on IOU-to-IOU coordination efforts prior to the Open Access mandate. As I describe in the next section, IOU-to-IOU agreements dulled competition between them, exploited TDUs, thwarted their efforts to compete, and carved up profitable capital investment opportunities. The IOUs' exclusionary approach persisted, even after FERC issued its Open Access mandate in 1996, as they continued to plan transmission expansion within their exclusive clubs, allowing them to withhold information from potential competitors and develop interstate networks for their own needs.[45]

II. THE GOLDEN AGE OF IOU DOMINANCE: FERC FAVORS VOLUNTARY COORDINATION UNDER SECTION 202 OVER POLICING IOU COLLUSION UNDER SECTIONS 205 AND 206

Transmission "is the heart of a modern electric power system."[46] It is the medium for coordinating supply and demand that enables the industry to unlock

44. FEDERAL POWER COMMISSION, 1970 NATIONAL POWER SURVEY at I-17-1 (1972) ("There are thousands of arrangements among systems from all segments of the industry providing for various degrees and methods of electrical coordination.") [hereinafter 1970 NATIONAL POWER SURVEY]. The FPC characterized its 1964 National Power Survey "as the most effective means of carrying out the provisions of section 202(a)." FEDERAL POWER COMMISSION, 1964 NATIONAL POWER SURVEY at 1 (1964) [hereinafter 1964 NATIONAL POWER SURVEY] . The Report provided "an outline for the coordinated growth of the industry" in order to unlock the "enormous potential benefits of a truly integrated system of power supply." The "heart of the report" describes an illustrative plan for "progressive enlargement of geographical areas of coordination." 1964 NATIONAL POWER SURVEY at II, 6, 199.

45. *See infra* notes 271–276 and accompanying text.

46. JOSKOW, *supra* note 16, at 63.

short-run and long-run efficiencies through trading and joint planning.[47] Because of transmission's "strategic importance,"[48] transmission-owning IOUs were able to dominate smaller transmission-dependent utilities and restrain the development of non-IOU generation.[49] Agreements among IOUs created "information cartels"[50] that colluded against their customers and potential competitors and impeded

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47. *Id.* at 64 (outlining efficiencies that utilities can unlock through coordination via transmission); *New England Power Pool Agreement*, 48 F.P.C. 538, at p. 549 (1972):

> The satisfactory performance of a power supply network requires close cooperation among component systems for accurate control of frequency, sharing of load regulating responsibility, and maintenance of power system stability. Financial benefits are often realized from staggered construction of large generating units, short-term capacity transactions, and interchanges of economy energy. Reduction of installed reserve capacity is made possible by mutual emergency assistance arrangements and associated coordinated transmission planning. Bulk power supply reliability is enhanced by interconnection agreements covering spinning reserves, reactive kilovolt-ampere requirements, emergency service, coordination of day-to-day operations, and coordination of maintenance schedules. Also, operating costs may be reduced through coordinated operation of interconnected systems. Electric utilities, which are unable individually to construct and take full advantage of large bulk power supply facilities, are able to obtain economic and operational benefits from such facilities, *inter alia*, by joining with neighboring systems in coordination arrangements.

48. 1964 NATIONAL POWER SURVEY, *supra* note 44, at 27 ("The strategic importance of transmission is much greater than indicated by its 10 percent average share in the overall cost of electricity. . . . Interconnection is the coordinating medium that makes possible the most efficient use of facilities in any area or region."); Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act; Policy Statement, 61 Fed. Reg. 68,595, 68,610 (Dec. 30, 1996) ("Limitations on available transmission capability that prevent competitors from participating in a market can give substantial market power to incumbents in the market"); *Extra-High-Voltage Electric Transmission Lines: Hearings Before the Comm. on Commerce,* 89th Cong. 14–15 (1966) (statement of FPC Comm'r Ross, member, Comm. on Commerce) ("[I]t is no longer the parties who control generation that control the industry--it is the parties who control the transmission, the arteries of the Industry, that control the destiny of the millions of rate payers of this Nation."); LEONARD W. WEISS, ANTITRUST IN THE ELECTRIC POWER INDUSTRY IN PROMOTING COMPETITION IN REGULATED MARKETS 135, 144–45 (Almarin Phillips ed. 1975) ("The ownership of transmission lines can be used to impose more monopoly in generation or more vertical integration on the power industry, or both, than is technically necessary.").

49. *See, e.g.,* New York v. FERC, 535 U.S. 1, 8 (2002) ("The utilities' control of transmission facilities gives them the power either to refuse to deliver energy produced by competitors or to deliver competitors' power on terms and conditions less favorable than those they apply to their own transmissions."); FERC, Policy Statement: Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act, 61 Fed. Reg. 68,595 at p. 68,616 (Dec. 30, 1996) ("A merger of transmission-owning utilities may have various effects on the grid, such as better planning, coordination, fewer pancaked rates, and *strategic control of regional transmission grids*. (emphasis added)); *Ohio Edison Co., et al.*, 81 F.E.R.C. ¶ 61,110, at p. 61,408 (1997) (noting potential for merged utility company's "ability to strategically plan and operate its transmission system to withhold generation"); *Am. Elec. Power Co. et al.*, 90 F.E.R.C. ¶ 61,242, at p. 61,785 (2000) (discussing how merged utility might "use transmission to frustrate competitor's access to relevant electricity markets" by "foreclosing competitor's access to [] transmission"); Narasimha Rao and Richard D. Tabors, *Transmission Markets: Stretching the Rules for Fun and Profit*, 13 ELEC. J. 1 (Jun. 2000) (explaining how IOUs that cover large territories and are also NERC security coordinators "control all the knobs" of the transmission network and are able to restrict access, even under FERC's open-access rules); CARL PECHMAN, REGULATING POWER: THE ECONOMICS OF ELECTRICITY IN THE INFORMATION AGE 100 (1993) ("Utilities have tremendous power over non-utility generators. The basis of this power is that the monopoly privileges granted utilities have allowed them to control access to both retail markets and the bulk power system . . . . The local utility is both a monopoly provider of back-up service . . . as well as a monopsonist when it comes to purchasing power . . . .").

50. Pechman, *supra* note 49, at 67–70 (describing power pools as "information cartels"); James Meeks, *Antitrust Concerns in the Modern Public Utility Environment*, NAT'L REGULATORY RESEARCH INST. (Apr. 1996), https://inis.iaea.org/collection/NCLCollectionStore/_Public/27/066/27066557.pdf?r=1&r=1:

oversight. Regionalizing decisionmaking also enabled IOUs to cartelize development of generation and transmission infrastructure, reinforcing their dominance over the power industry.

Since the 1920s, IOUs routinely connected to each other via transmission lines, initially to provide backup power during outages at their own facilities and share resources in order to economically meet peak consumer demand.[51] Agreements also provided for exchange of so-called economy energy when one utility had energy available at a cost that would reduce the other utility's expenses by displacing more expensive generation on its own system.[52] Most IOU-to-IOU interconnection agreements were premised on "mutuality of benefits," and many services were returned in-kind.[53] Large IOUs preferred to connect to each other, in part because of "decades of intra-industry animosities"[54] between IOUs and

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> exchange of information can raise antitrust problems to the extent that it can facilitate overt or tacit price collusion. . . . It seems clear here that some possibility of misuse of the information to facilitate a restraint of trade is tolerable given the strong public benefit of such joint activity. However, any exchange that exceeds the need presented by the justification will put the joint venture in jeopardy. This seems especially critical given the likely market structure in parts of these industries and the accompanying strong possibility of tacit or oligopoly pricing.

Peter C. Carstensen, *Creating Workably Competitive Wholesale Markets in Energy: Necessary Conditions, Structure, and Conduct*, 85 ENVTL. AND ENERGY L. & POLICY J. 85, 105 (2006) ("Markets with few competitors are prone to tacit or explicit collusion . . . Successful collusion is much more feasible when there are only a handful of firms that must cooperate to exploit the market"); *Id.* at 132 (observing that in the electric power industry the need for agreement about technical specifications "provides fertile ground for the parties to engage in [] tacit collusion and to adopt unduly exclusionary or exploitative regulations"); Robert H. Lande and Howard P. Marvel, *The Three Types of Collusion: Fixing Prices, Rivals, and Rules*, 2000 WISC. L. REV. 941, 942 (finding that in some cases "collusion . . . permitted firms to manipulate the rules under which the independent decisions of the colluding firms were made. . . . [Firms] competed less vigorously or in a restricted manner in the environment their collusion had altered. . . . The most straightforward examples of this type of collusion involve efforts to soften competition among rivals by limiting the information available to consumers.").

51. JULIE A. COHN, THE GRID (2017); THOMAS P. HUGHES, NETWORKS OF POWER: ELECTRIFICATION IN WESTERN SOCIETY, 1880–1930 363 (1993); *See also* 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-1; U.S. DEP'T OF ENERGY, ECONOMIC REGULATORY ADMINISTRATION, OFFICE OF UTILITY SYSTEMS, DOE/ERA 56-2, THE NATIONAL POWER GRID STUDY: VOLUME II TECHNICAL STUDY REPORTS 153 (1979) [hereinafter 1979 NATIONAL POWER GRID STUDY].

52. Power Pooling in the U.S., *supra* note 16, at 34; 1964 NATIONAL POWER SURVEY, *supra* note 44, at 29; *See, e.g., Jersey Cent. Power & Light*, 4 F.P.C. 554 (1944) (noting that two IOUs traded "Economy Energy" since 1931); Regulation of Electricity Sales-for-Resale and Transmission Service, 50 Fed. Reg. 23,445, 23,446–47 n.7 (Jun. 4, 1985) ("Economy energy is unconditionally interruptible energy supplied during a period, usually one hour, when the seller's incremental energy cost is less than the buyer's decremental energy costs").

53. Abraham Gerber, *Power Pools and Joint Plant Ownership*, 82 PUB. UTIL. FORTNIGHTLY 23, 26–29 (Sep. 12, 1968) (outlining how small systems reap seven types of benefits from interconnecting with large systems and arguing that because there is no "mutuality of benefits" small systems should pay large utilities for those benefits).

54. 1964 NATIONAL POWER SURVEY, *supra* note 44, at 275 (noting that "psychological barriers" stand in the way of coordination and observing that municipal and cooperative utilities "distrust" IOUs and are therefore "hesitant to sacrifice any of their autonomy by purchasing power from" IOUs); *see also* PHILIP SPORN, THE SOCIAL ORGANIZATION OF ELECTRIC POWER SUPPLY IN MODERN SOCIETIES (1971) (arguing that IOUs are superior to publicly owned power systems); 1979 NATIONAL POWER GRID STUDY, *supra* note 51, at 49 ("Investor-owned systems tend to regard public systems as having an unfair advantage because of the difference in financial structure, and they are often reluctant to assist the public utilities by wheeling less expensive public power."); *In the Matter of Alabama Power*, 5 N.R.C. 804, 946–957 (1977) (recounting efforts by southeastern IOUs to develop coordination agreements in the late 1960s and finding that Alabama Power's "conduct with respect to deterring,

TDUs. In addition, IOUs believed that coordinating with small utilities offered few, if any, economic or reliability benefits.[55]

To exchange power, utilities must share information in order to maintain electrical stability over their connected systems.[56] Supply and demand must be in balance, and the voltage, frequency, and other operating parameters of the shared system must remain within safe limits.[57] Bilateral connection agreements between IOUs typically established a committee of employees that coordinated operations.[58] IOUs shared information about generator availability and costs, transmission capacity, and other technical and economic factors.[59]

More sophisticated coordination arrangements entail greater information sharing. Regional, multi-IOU "power pools" facilitated varying levels of cooperation and coordination.[60] Pool agreements might have committed IOUs to rendering emergency assistance, prescribed for each IOU an amount of reserve capacity, or standardized terms and conditions of economy energy exchanges.[61] In the Northeast and Michigan, IOUs developed so-called "tight" power pools, where each IOU ceded dispatch of its power plants to the jointly managed pool in order to meet aggregate demand with the least-cost mix of generation resources across the pool.[62] Elsewhere, holding companies that owned contiguous IOUs similarly coordinated operations through joint dispatch.[63] Implementing these coordinated

discouraging and excluding publicly owned utilities from economic coordination in this matter is consistent with the anticompetitive attitude of the Southern System . . . Applicant clearly intended to, and did, deny in concert with other utilities, publicly owned utilities in its service area the benefits of economic coordination in order to eliminate competition from them.").

55. Power Pooling in the U.S., *supra* note 16, at 39–40. Some IOUs believed that they should receive a share of a small utility's savings that it would derive from the IOU pool. *Id. But see* Gainesville Utilities Dep't v. Florida Power Corp., 402 U.S. 515, 526 (noting FERC's findings that the IOU would benefit from connecting to the municipal utility).

56. HUGHES, *supra* note 51, at 368−71 (observing that with the development in the 1920s of multi-utility regional systems, "electrical engineers began working out a science of information and control . . . [and] increasingly used concepts such as 'coordination,' 'integration,' 'control,' 'flow,' 'concentration,' 'centralization,' and 'rationalization.'").

57. *See supra* note 47; ALEXANDRA VON MEIER ELECTRIC POWER SYSTEMS: A CONCEPTUAL INTRODUCTION 260–268 (2006) (summarizing that the "prime directive" for system planners and operators is to balance supply and demand and explaining that this balancing act "occurs on multiple levels, with control methods appropriate to each time scale").

58. *See, e.g., Re Pub. Serv. Co. of Ind.*, 34 F.P.C. 1513, at p. 1516 (1965); Power Pooling in the U.S., *supra* note 16, at 33.

59. *See* Pechman, *supra* note 49, at 62–67 (describing the operations of the New York Power Pool); Meeks, *Antitrust Concerns*, *supra* note 50, at 81 ("This pooling requires . . . exchange of information regarding costs of production . . . and coordinated monitoring of line flow and power movements to maintain reliability and the security of the participating systems"); Power Pooling in the U.S., *supra* note 16, at 27–31; 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-4 ("In more highly developed pools, the day-to-day operation, maintenance, and accounting may be handled by a pool manager and other full-time personnel.").

60. 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-4, I-17-22.

61. *See, e.g.*, *Pub. Serv. Co. of Ind.*, 31 F.P.C. 1064, at p. 1065 (1964); Curtis Cramer and John Tschirhart, *Power Pooling: An Exercise in Industrial Coordination*, 59 LAND ECON. 24, 31 (Feb. 1983); Power Pooling in the U.S., *supra* note 16, at 33–38 (describing various power pool arrangements).

62. Cramer and Tschirhart, *supra* note 61, at 32.

63. *See, e.g.,* 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-5–7 (noting that the following utility holding companies managed power pools of member companies: American Electric Power, Allegheny Power

arrangements required a constant flow of information from IOUs to pool-assigned staff about generation and transmission availability, consumer demand, and energy transfers into and out of the pool.[64] To facilitate seamless energy trading and capacity sharing, pool agreements set uniform terms and conditions for the use of each pool member's separately owned transmission assets.[65]

Shared information, along with pool rules for dispatching plants and allocating costs, ultimately determined the cost of power and IOU profits.[66] IOU-led dispatch prioritized member plants over non-members' generators.[67] Cost allocation rules could benefit members and make available only higher-cost power to transmission-dependent non-pool members.[68] An IOU-dominated pool could effectively monopolize wholesale power transactions across the region by refusing to transport power from competing generators or blocking TDUs from accessing particular sources of power.[69] By emphasizing cooperation and shared savings, pool dispatch also suppressed competition among IOU pool members.[70]

Long-term planning procedures outlined in pool agreements were premised on IOUs cartelizing infrastructure development.[71] Planning arrangements allowed

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Systems, Southern Company, Middle South Utilities System, and Texas Utilities Systems); *Ark. Power & Light Co.*, 34 F.P.C. 747, at pp. 749–750 (1965) (describing operations of a multi-state power pool controlled by a utility holding company).

64. *Supra* note 59.

65. Power Pooling in the U.S., *supra* note 16, at 35 (noting that the NEPOOL agreement provides a pool-wide transmission rate that is available to all members while PJM does not charge for transmission).

66. *See* Pechman, *supra* note 49, at 67–69.

67. *Id.* at 74 (explaining that by designating certain plants as "must run," IOUs were able to discourage non-pool plants and gain a degree of market control by reducing the number of hours in which independent plants can generate power).

68. *See, e.g., Re Pub. Serv. Co. of Okla.*, 25 F.P.C. 656 (1961) (The FPC notes that "many problems and issues presented in an electric rate case involving a mutual exchange of services in a power pooling or interchange arrangement are different from those arising in a rate proceeding involving a one-way service agreement" in part because "problems of classification and allocation of costs [among parties] frequently involve judgment factors." The FPC ultimately approved the filed rates and coordination agreement. The hearing officer found that the "exactly how the rate levels . . . were developed by [the IOU] has never been made completely clear on an arithmetical basis" and noted that the IOU's chairman allocated some of the costs "on the basis of his personal judgment" *Id.* at pp. 696, 699.

69. Pechman, *supra* note 49, at 61–62, 72; *See also* Meeks, *Concentration in the Electric Power Industry*, *supra* note 31, at 108–109, 112–113, 126.

70. Power Pooling in the U.S., *supra* note 16, at 62 ("Coordination may lessen the intensity of rivalry within the industry. The likelihood of collusion or parallel behavior is increased when industry participants come together to make joint planning and operating decisions") (quoting David W. Penn, James B. Delaney, and T. Crawford Honeycutt, Nuclear Regulatory Commission Staff, "Coordination, Competition, and Regulation in the Electric Utility Industry," NUREG-75/061, Jun. 1975); James F. Fairman and John C. Scott, *Transmission, Power Pools, and Competition in the Electric Utility Industry*, 28 HASTINGS L.J. 1159, 1194 (1977) (noting that pooling can remove the "threat of being undersold," reduce price competition and utility incentives to reduce costs).

71. 1979 NATIONAL POWER GRID STUDY, *supra* note 51, at 28 (noting that the "majority of planning which currently takes place is at the power pool level"); 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-24 ("Most joint ownership arrangements are among utilities within the same power pool or planning organization."); *see also id.* at I-17-4 n.4 ("Membership of most power pools consists entirely of the larger investor-owned systems" but noting that in New England two publicly owned utilities are pool members); *Mid-Continent Area Power Pool Agreement*, 58 F.P.C. 2622, at p. 2662 (TDUs alleged that the IOU-led pool "controls area-wide planning and has established a club to which small systems contemplating bulk power facilities must come 'hat

IOUs to co-own facilities[72] or take turns building new generators,[73] and enabled a member IOU to grow its load until it could rationalize constructing a plant (and earn a state-set rate of return on that investment).[74] In general, IOUs did not invite non-pool members to jointly develop new power plants.[75] Joint development arrangements were only feasible when compatible with the expansion plans and financial goals of each individual member IOU.[76] Meanwhile, smaller utilities, including most non-profits, were unable to support construction of new generators

in hand.'" FERC did not accept that characterization, but did conclude that membership rules unduly discriminated against smaller utilities and ordered the pool to provide better access to its planning processes. *Id.* at 2622.).

72. 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-25 ("A recent development of great significance is the increasing use of joint ownership of facilities by members of formal power pools."). The report notes that 27.6 GW of jointly developed pool capacity would be put in service from 1968 to 1975 and pools had procedures to "utilize joint enterprises on a continuing basis.").

73. 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-23 (describing various approaches to "staggered construction," where IOUs take turns building new plants); *Mid-Continent Area Power Pool*, 58 F.P.C. 2622, at p. 2649 (1977) ("Emphasis is placed upon staggered and timely construction of large generating units"); Abraham Gerber, *Power Pools and Joint Plant Ownership*, 82 PUB. UTIL. FORTNIGHTLY 23, 26 (Sept. 12, 1968) (stating that under the Carolina-Virginia (CARVA) power pool agreement, each new baseload unit is built by a single IOU and sized so that load growth on that IOU's system absorbs the excess capacity while other systems purchase the excess capacity during that interval).

74. *Pub. Serv. Co. of Ind.*, 31 F.P.C. 1064, at p. 1067.

75. Small utilities urged the Atomic Energy Commission and the Securities and Exchange Commission to consider antitrust law in its approval of IOUs' nuclear power plant construction applications. *See* City of Statesville v. Atomic Energy Commission, 441 F.2d 962 (D.C. Cir. 1969) (affirming AEC despite complaints from municipalities that they were denied opportunities to participate in an IOU consortium developing a nuclear reactor); Municipal Elec. Ass'n of Mass. v. SEC, 413 F.2d 1052 (D.C. Cir. 1969) (remanding an order approving IOUs' acquisition of stock of two nuclear generating companies because the SEC failed to consider municipal utilities' argument that they must be given an opportunity to obtain the associated low-cost power); *see also* Power Pooling in the U.S., *supra* note 16, at 74 (reporting that NEPOOL management committee determines whether proposed generating units to be installed by members receive "pool-planned" status, which provides beneficial transmission access). By the late 1970s, in-part due to "inflation-caused financing problems for investor-owned systems," some IOUs collaborated with municipal and cooperative utilities in power plant development. Power Pooling in the U.S., *supra* note 16, at 12.

76. Power Pooling in the U.S., *supra* note 16, at 103 ("Staggered construction, jointly owned generating units, and other informal coordination techniques to achieve improved economy can be employed only when they are compatible with the generation expansion plans of individual utilities."); *Id.* at 116 ("Under prevailing pool practices, [MAPP] members develop their individual generation and transmission plans and act independently to identify and implement coordination opportunities with other pool members. Staggered construction, jointly owned generation . . . and other coordinating opportunities . . . are employed to modify individual utility expansion plans so as to further reduce investment and operating costs."); *Id.* at 243 (Letter from the Mid-America Interpool Network stating that the "rights and duties of IOU power systems, among them the right to compete for investment capital and the duties to pay a return to investors . . . have placed some unavoidable restraints on complete power pooling"); *Id.* at 254 (Letter from Southwest Power Pool observing that because full coordination renders only one to three percent savings "one can readily understand why utility executives are reluctant to give up their autonomy"); 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-9 (noting that "corporate rate-base requirements" are an obstacle to coordinated planning of new construction and observing that IOU management may be reluctant to "subordinate its individual decisions" over construction to the pool due to corporate preferences for profitable capital investments over cost-saving cooperative agreements and listing other factors).

by themselves,[77] and became increasingly dependent on transmission-owning IOUs to generate and deliver power.[78]

IOU pools were also a mechanism for evading regulatory scrutiny. Pool agreements were beyond the jurisdiction of state regulators. Only FERC could directly regulate their terms, although in practice many IOUs did not file relevant rate schedules with FERC.[79] As an IOU shifted its operations from serving captive ratepayers with its own generation to providing energy to consumers through an

77. 1964 NATIONAL POWER SURVEY, *supra* note 44, at 272; Power Pooling in the U.S., *supra* note 16, at 166.

78. Meeks, *Concentration in the Electric Power Industry*, *supra* note 31, at 68 ("Given the increasing reliance upon wholesale purchases by many of the smaller systems of all three varieties, control over transmission becomes a most important factor in analyzing the wholesale market."); Power Pooling in the U.S., *supra* note 16, at 39–40.

79. Joseph C. Swidler, POWER AND THE PUBLIC INTEREST at 144–18 (2002). The author explains that when he became FPC Chair in 1961 it had been common practice for IOUs not to file wholesale rate schedules, "even if the company in question was part of an interconnected network covering several states," and he sought to require or induce IOUs to file all interstate wholesale rates. Following the Supreme Court's decision in FPC v. Southern Cal. Edison. Co., 376 U.S. 205 (1964), the FPC advised utilities that it would not investigate past failures to file wholesale rate schedules. *Rate Schedules and Public Utilities*, Order No. 282, 31 F.P.C 972 (1964). In its Supreme Court brief, the FPC told the court that ruling in its favor would provide it with clear authority to regulate in-state wholesale sales of utilities participating in power pools. FPC, Brief of the Federal Power Commission, 1963 WL 106064, at *35– 40 (Sep. 3, 1963). In several proceedings initiated shortly after the decision, the FPC found jurisdiction over wholesale sales by IOUs to in-state entities, and found it relevant that the IOU operated as part of an interconnected interstate system. *See Indiana & Michigan Electric Co.*, 33 F.P.C. 739 (1965)*, aff'd,* Indiana & Michigan Elec. Co v. FPC, 365 F.2d 180 (7th Cir. 1966); *Re Arkansas Power & Light Co.*, 34 F.P.C. 747 (1965), *aff'd*, Arkansas Power & Light Co. v. FPC, 368 F.2d 376 (8th Cir. 1966); *Re Public Service Co. of Indiana,* 34 F.P.C. 1513 (1965), *aff'd*, Public Service Co. of Indiana v. FPC, 375 F.2d 100 (7th Cir. 1967); *Re Cincinnati Gas & Electric Co.*, 35 F.P.C. 99 (1966)*, aff'd*, Cincinnati Gas & Electric Co. v. FPC, 376 F.2d 506 (6th Cir. 1967); *Alabama Electric Co-op v. Alabama Power Co.*, 38 F.P.C. 962 (1967). *See also* Senate Hearings on Antitrust and Monopoly, *supra* note 14, at 792–93. Former FPC Commissioner Charles R. Ross (1961–68) explained that the FPC "has not actively or aggressively seen fit to inquire into the many pooling [] and joint generation agreements . . . There seems to be an understanding that it is advantageous to have the companies file such agreements, and that for the time being the Commission should hold off analyzing them."). Even where IOU power pool members did file rate schedules, allocating costs of service provided by a power pool was an inexact science, and the FPC relied on the IOU's own records and judgments. *See supra* note 68.

interstate pool, state regulators lost visibility into the utility's operations.[80] By accounting for energy through the pool, an IOU could obscure their operations from state regulators. This shift effectively made federal oversight more important.[81]

FERC generally tolerated the anti-competitive effects of IOU pooling agreements, believing that efficiency gains associated with such voluntary coordination under section 202 were greater than any benefits that might be unlocked through its more aggressive use of sections 205 and 206.[82] But by the late 1970s, following four Supreme Court decisions about the intersection of the FPA and antitrust law,[83] FERC recognized that its determinations under sections 205 and 206 must address effects on competition.[84] With regard to IOU-dominated pool agreements, FERC considered competition by scrutinizing pool membership criteria to ensure that

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80. *See* Pechman, *supra* note 49, at 69–70 (explaining that IOUs prevent state regulators from investigating how utilities "manipulate information" in power pool cost calculations by declaring the model proprietary, and thereby "withhold[ing] information and inhibit[ing] a state regulatory commission's ability to effectively regulate"); *Id.* at 71–75 (concluding that the decision of the New York Power Pool to leave dispatch decisions up to each IOU rather than centrally coordinate dispatch violated IOUs' duties under state law to provide least-cost service, but state regulators were powerless to order the federally regulated pool to change course); *Id.* at 83–95 (explaining that reserve margins that were once regulated by the state shifted to power pool control and outlining how it is "possible to bias" the calculation, "which in turn increases the level of investment required"); Charles G. Stalon and Reinier H.J.H. Lock, *State-Federal Relations in the Economic Regulation of Energy*, 7 YALE J. ON REG. 427, 441 (noting that multi-state utilities found it convenient to "maintain the façade" of single-state regulation and regulators often went along, "cling[ing] to the myth of self-sufficient single state operating companies"); *Id.* at 451 (noting that with utilities increasingly meeting resource adequacy needs through wholesale purchases "state regulators were forced to balance the undesirability of losing jurisdiction over local utilities that purchased from neighboring utilities against the increased risks associated with utilities' building their own capacity to meet local needs"); FPC, Brief for the Federal Power Commission, Supreme Court Docket of FPC v. Southern Cal. Edison, 1963 WL 106064, at *12–13 (stating that "state commissions lack th[e] essential legal authority and cannot effectively deal with" wholesale sales effectuated through an interstate power pool because they lack the "highly specialized staff and, even more indispensable, the legal authority to compel production of the books and records of all members of the system" need to ensure just and reasonable rates); Senate Hearings on Antitrust and Monopoly, *supra* note 14, at 656 (Montana Senator Metcalf testifying that IOU "reporting requirements . . . are a sham" and noting that "terms of pooling arrangements among utilities are hidden").

81. By 1970, IOUs had organized 21 power pools that included 60% of the nation's generation capacity. 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-2–7. 1964 NATIONAL POWER SURVEY, *supra* note 44, at Vol II:365 ("The need for increased pooling and coordination has primarily arisen out of the technological developments in the art of generating and transmitting electric power which have made the optimum economical units too large for all but the biggest systems."). Following a regional blackout in 1965, reliability benefits associated with interconnection drove further coordination and pooling efforts. 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-1-15.

82. *See, e.g., New England Power Pool Agreement*, 56 F.P.C. 1562, at p. 1587 (1976) ("Although it appears that NEPOOL might narrow the basis for wholesale competition . . . reduction in cost of service resulting from this new-found coordination is most certainly in the public interest and outweighs any possible reduction in wholesale competition."); *Mid-Continent Area Power Pool Agreement*, 58 F.P.C. 2622, at p. 2626 (1977), *aff'd*, *Central Iowa Power Cooperative*, 606 F.2d at 1162–1163; *Public Service Co. of Indiana, et al.,* 47 F.P.C. 1396, at p. 1407, *remanded by,* City of Huntingburg, Indiana v. FERC, 498 F.2d 778, 785 (D.C. Cir. 1974); Order No. 888, *supra* note 31, at 21,568.

83. Gainesville Utilities Dept. v. Florida Power Corp., 402 U.S. 515 (1971); Gulf States Utilities v. FPC, 411 U.S. 747 (1973); Otter Tail Power v. U.S., 410 U.S. 366 (1973); FPC v. Conway Corp., 426 U.S. 271 (1976).

84. *Re Missouri Power & Light Co.*, 5 F.E.R.C.¶ 61,086, at p. 61,140–41(1978); Central Power & Light Co. v. FERC, 575 F.2d 937, 938 (D.C. Cir. 1978) ("While the FERC does not have authority to adjudicate antitrust actions, antitrust considerations are relevant when it exercises its discretion subject to a public interest mandate.").

they did not unduly discriminate against TDUs and other non-IOU entities.[85] But FERC continued to dismiss sweeping complaints about the anti-competitive nature of IOU-dominated pools.[86]

By then, the industry was in the midst of significant and rapid changes. Sharp increases in the cost of utility service in the 1970s[87] led energy-intensive industrial consumers to construct their own generation rather than rely solely on an IOU for power[88] and spurred Congress to enable new entry into the wholesale power business and expand FERC's authority to facilitate sales of non-IOU generated energy.[89] Meanwhile, regulators in many states required IOUs to conduct competitive procurements for new generation rather than simply authorizing the IOU to construct a power plant itself.[90] In 1992, Congress removed a legal barrier to non-utility generation, modifying financial regulations that hindered investment.[91] For the first time, new non-IOU generation projects outpaced IOU additions to the nation's electric system.[92] As consumer rates soared, IOUs' forecasted demand growth failed to materialize and their systems were bloated with expensive and unneeded capacity.[93]

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85. *See, e.g., Mid-Continent Area Power Pool Agreement*, 58 F.P.C. 2622, at p. 2635–36, *aff'd*, *Central Iowa Power Cooperative*, 606 F.2d at 1171–72. For an example of FERC's earlier approach, *see Re Western Massachusetts Electric Co.*, 39 F.P.C. 723, at p. 737 (1968) (noting that the municipal utilities applied to join a regional group controlled by IOUs and were denied because the group's bylaws limit membership to IOUs); Power Pooling in the U.S., *supra* note 16, at 195 (Letter from the APPA noting a "history of difficulties that public power systems have generally encountered in gaining admittance to voluntary coordination agreements"). Senate Hearings on Antitrust and Monopoly, *supra* note 14, at 431 (stating that an agreement among New England IOUs that excluded municipals "appeared to be a formidable combination in restraint of trade.").

86. *Mid-Continent Area Power Pool Agreement*, 58 F.P.C. at pp. 2651, 2656 (1977) (Opponents of the pool agreement alleged that it "establishe[d] a machinery for private regulation of industry in violation of the basic public-interest standard[]" of the FPA and fixed prices and restrained trade in violation of antitrust law.); *City of Frankfort Kentucky v. Kentucky Utilities Co., et al.*, 3 F.E.R.C. ¶ 63,004, at p. 65,032 (1977) (A Kentucky city argued that "through monopolistic control over transmission" certain IOUs "monopolized and divided up territory among" themselves while "segregating and isolating municipals and co-ops . . . and preventing them from doing business with each other and with private utilities except on restrictive terms."); *New England Power Pool Agreement*, 48 F.P.C. 1477, at p. 1478 (1972) (Municipal utilities alleged that FERC "erred in failing to recognize the effects of permitting all the large utilities, legal competitors of each other, to combine all of the generation and all of the transmission in [the region] under an all-encompassing agreement without protecting the rights and opportunities of the small municipal and cooperative systems.").

87. FERC, The Transmission Task Force's Report to the Commission, Electricity Transmission: Realities, Theory, and Policy Alternatives, at 34 (Oct. 1989) ("Pressure for wholesale customer bypass of its host utility as its only supplier has never been greater than during the past ten years.") [hereinafter Transmission Task Force].

88. Stalon and Lock, *supra* note 80, at 450. Some industrial users merely threatened to build cogeneration, in the hope of a receiving a lower rate from the utility. Transmission Task Force, *supra* note 87, at 36.

89. 16 U.S.C. § 824a-3(j), (k).

90. Stalon and Lock, *supra* note 80, at 450.

91. Jeffrey D. Watkiss & Douglas W. Smith, *The Energy Policy Act of 1992: A Watershed for Competition in the Wholesale Power Market*, 10 YALE J. ON REG. 447, 449 (1993).

92. Bernard S. Black & Richard J. Pierce, Jr., *The Choice Between Markets and Central Planning in Regulating the U.S. Electricity Industry*, 93 COL. L. REV. 1339, 1349 (1993).

93. Stalon and Lock, *supra* note 80, at 432 ("Economic forces dramatically reduced the rate of demand growth for electricity and increased the real costs and risks associated with building new generation capacity.").

These developments put pressure on FERC to unlock transmission access for a burgeoning independent generation market.[94] Reformists hoped that wholesale competition would provide incentives to control generation costs, shift development risks from captive IOU ratepayers to investors in non-IOU generation, encourage innovation in generation technology and business models, and motivate investors to develop new projects.[95] To realize those benefits, FERC would have to address IOU control of transmission and break up the IOU transmission clubs.

III. FERC ADDRESSES IOU TRANSMISSION DOMINANCE AND INITIATES THE RISE OF INDEPENDENT OPERATORS

A. FERC Mandates Comparable Transmission Service and Information Transparency Under Section 206

FERC understood that IOUs were an obstacle to the development of competitive markets for wholesale power.[96] By the late 1980s, FERC began taking significant but cautious steps to address anti-competitive IOU transmission service.[97] For example, in a merger proceeding, FERC determined that the merged entity could exercise market power through its transmission control and therefore conditioned its merger approval on the merged entity's provision of fair transmission service to third parties.[98] In an application for permission to sell power at market-based rates, an IOU committed to file a transmission tariff that would "ensure that

94. FERC, Notice of Public Conference and Request for Comments on Electricity Issues, 55 F.E.R.C. ¶ 61,069 (1991) ("As competitive markets in electricity generation are emerging, increasing pressure is placed on providing expanded transmission service. Transmission, however, remains a natural monopoly."); *see also* Black and Pierce, *supra* note 92, at 1344–1350 (outlining factors that upset the status quo in utility regulation and "turned competitive markets for wholesale power from a theoretical possibility into a strategy that is supported by almost all interested parties").

95. Paul L. Joskow, *Electricity Sector Restructuring and Competition: Lessons Learned*, 40 CUADERNOS DI ECONOMIA 554 (Dec. 2003).

96. Transmission Task Force, *supra* note 87, at 67 (concluding that transmission or lack thereof can be a barrier to entry in the emerging non-utility generation market and that "clear examples" of IOUs exercising market power to "stifle competition are abundant"); *Id.* at 187 ("The current market power of transmission incumbents is so pervasive that independent power producers are unlikely to be willing to take substantial financial risks in the absence of assured access to the grid at reasonable prices"); FERC, Notice of Inquiry, Regulation of Electricity Sales-for-Resale and Transmission Service, Phase 1, 31 F.E.R.C. ¶ 61,228 (1985) ("Availability of transmission services is a necessary element to competitive markets.").

97. In fairness to FERC, it moved in the late 1970s to address undue discrimination on an IOU-by-IOU basis but federal courts rejected some of its more aggressive remedies. *See* Harvey L. Reiter, *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation Under the Federal Power and Natural Gas Acts*, 18 LAND & WATER L. REV. 1, 20–28 (1983) (discussing Florida Power & Light Co. v. FERC, 660 F.2d 668 (5th Cir. 1981) and New York State Electric & Gas Co. v. FERC, 638 F.2d 288 (2d Cir. 1981)).

98. *See, e.g., Utah Power & Light Co., et al.,* , 45 F.E.R.C. ¶ 61,095, at p. 61,288–90; *order on reh'g*, 47 F.E.R.C. ¶ 61,209, at p. 61,736 ("the transmission access conditions we imposed were the minimum necessary to alleviate the probable anticompetitive effects of the merger by preventing the merged company from exercising its market power to foreclose access by competitors to the relevant bulk power markets."); *Pub. Serv. Co. of Colorado*, 58 F.E.R.C. ¶ 61,322, at p. 62,038 (1992) ("The Commission's fundamental competitive concern as expressed in recent decisions is that an increase in control over key transmission facilities may lead to a greater ability to block competing lower-cost suppliers from reaching wholesale electric customers."). Following the Utah/Pacificorp merger proceeding, other IOUs proposed similar transmission access conditions in merger proceedings. *See Kansas City Power & Light Co.*, 53 F.E.R.C. ¶ 61,097, at p. 61,276 (1990).

[it] cannot use its control over its transmission system to exercise market power in negotiating long-term firm power sales."[99] FERC concluded that this "open-access transmission service" would mitigate the utility's transmission market power and would promote competition.[100]

FERC's IOU-by-IOU efforts did not trigger industry-wide reforms. By 1995, FERC found that only twenty-one IOUs had "any form of open-access transmission,"[101] while the "vast majority of transmission-owning utilities ha[d] not agreed to give up their market power voluntarily."[102] Seeking to accelerate progress towards open and competitive wholesale markets, FERC proposed to address IOUs' anti-competitive transmission service on an industry-wide basis. It concluded that

> Utilities owning or controlling transmission facilities possess substantial market power; that, as profit maximizing firms, they have and will continue to exercise that market power in order to maintain and increase market share, and will thus deny their wholesale customers access to competitively priced electric generation; and that these unduly discriminatory practices will deny consumers the substantial benefits of lower electricity prices."[103]

FERC acknowledged that its "prior willingness to tolerate the use of monopoly power over transmission to maintain and aggregate the utility's market power over generation occurred in the context of an industry structured largely as vertically integrated regulated monopolies."[104] In that environment, FERC had concluded "competition generally was not meaningfully available as a means to discipline prices."[105] However, given numerous changes in the industry, FERC determined that it had to review "discriminatory practices that once did not constitute undue discrimination."[106] Absent regulatory intervention, FERC predicted that IOUs would continue to discriminate because "the inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets."[107]

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99. *Pub. Serv. Co. of Indiana*, 49 F.E.R.C. ¶ 61,346, at p. 62,239 (1989); *see also Pub. Serv. Co. of Indiana*, 51 F.E.R.C. ¶ 61,367 (1990) (approving open-access transmission tariff), *order on reh'g,* 52 F.E.R.C. ¶ 61,260, *appeal dismissed,* Northern Indiana Public Service Co. v. FERC, 954 F.2d 736 (1992). *See also Citizens Power & Light Corp.*, 48 F.E.R.C. ¶ 61,210 (1989) (approving application to sell power at "market-based" rates, in part because applicant did not own transmission facilities and "the most likely route to market power in today's electric utility industry lies through ownership or control of transmission facilities").

100. *Pub. Serv. Co. of Indiana*, 49 F.E.R.C. ¶ 61,346, at p. 62,249.

101. Order No. 888 NOPR, *supra* note 31, at 17,671.

102. *Id.* at 17,676.

103. *Id.* at 17,665; *id.* at 17,664 ("market power through control of transmission is the single greatest impediment to competition"); *id.* at 17,675–77 (cataloging discriminatory IOU transmission practices).

104. Order No. 888, *supra* note 31, at 21,568.

105. *Id.*

106. *Id.*

107. *Id.* at 21,567; Order No. 888-A, *Promoting Wholesale Competition through Open Access Non-Discriminatory Transmission Services by Public Utilities,* 62 Fed. Reg. 12,274–75 ("Utility practices that were acceptable in past years, if permitted to continue, will smother the fledgling competition in electricity markets . . .") [hereinafter Order No. 888-A].

Having found undue discrimination under section 206, FERC took remedial action on an industry-wide basis. It ordered all IOUs to file open-access transmission tariffs that would provide all customers with transmission service that is comparable to the service that IOUs provide for their own power marketing operations.[108] To support this comparability goal, FERC required IOUs to "unbundle" wholesale energy sales and transmission service by charging separate rates for each and taking transmission service for their own power marketing activities under their own tariffs. FERC also required IOUs to unbundle their own operations by separating their power marketing and transmission personnel pursuant to codes of conduct that would prohibit employees operating the transmission network from providing non-public information to power marketing personnel. FERC intended for these reforms to deprive IOUs of informational advantages they had in the power marketing business. To guide their wholesale market decisions, IOU power marketing personnel would have to use the same information that their transmission customers used.[109]

In a concurrently issued order, FERC supported this "functional unbundling" mandate with rules requiring IOUs to publish, on a real-time basis, information about their transmission systems that is available to their employees and that is pertinent to decisions they make involving the sale or purchase of electricity.[110] By "open[ing] up the 'black box' of [] transmission system information," and separating IOU employees by function, FERC aimed to "ensure that the utility does not use its access to information about transmission to unfairly benefit its own or its affiliates' sales."[111]

FERC found its comparability and information transparency requirements were "not enough to cure undue discrimination in transmission if those public utilities can continue to trade with a selective group within a power pool that discriminatorily excludes others from becoming a member and that provides preferential intra-pool transmission rights and rates."[112] FERC conceded that it had previously tolerated discriminatory pool agreements because they improved the industry's efficiency even as they reinforced IOU market power.[113] Given the changes in the industry, FERC ordered IOUs to remove provisions in power pool agreements that granted members superior transmission access.[114] This mandate struck at the heart of IOU-dominated power pools.

108. Order No. 2000, *supra* note 36, at pg. 210 (stating that in Order No. 888 its "primary focus, both in terms of access and pricing was comparability; that is, all transmission users should receive access under rates, terms and conditions comparable to those the transmitting utility applies to itself to serve its own customers"); Order No. 888, *supra* note 31, at 21,547–21,549 (discussing FERC's "Comparability Standard").

109. Order No. 888-A, *supra* note 107, at 12,276; Order No. 888, *supra* note 31, at 21,552.

110. Order No. 889, *Open Access Same-Time Information System (Formerly Real-Time Information Networks) and Standards of Conduct*, 61 Fed. Reg. 21,737 (1996).

111. *Id*. at 21,740.

112. Order No. 888, *supra* note 31, at 21,593.

113. Order No. 888-A, *supra* note 107, at 12,296 ("Given the . . . efficiencies that could be gained through encouragement of coordination and pooling transactions, the Commission was willing to accept utility practices that provided third parties with transmission services that were distinctly inferior to the utility's own uses of the transmission system.")

114. Order No. 888, *supra* note 31, at 21,541.

FERC permitted IOUs to remedy unduly discriminatory power pools by disbanding them and creating Independent System Operators (ISOs), new entities that would operate utility-owned transmission facilities.[115] ISOs would be "public utilities" under the FPA because they would "operate[] facilities subject to the jurisdiction" of FERC.[116] As such, each ISO would have to maintain an OATT that is "just and reasonable and not unduly discriminatory," standards that would include compliance with FERC's Open-Access orders (Orders No. 888 and 889).

To foster ISOs that would efficiently operate the bulk power system and mitigate IOU transmission dominance, FERC articulated eleven "principles" to guide development of a "properly constituted ISO."[117] FERC's first and "fundamental"[118] principle was that an ISO's "governance should be structured in a fair and non-discriminatory manner."[119] Because "the primary purpose of an ISO is to ensure fair and non-discriminatory access to transmission services," FERC determined that

> an ISO should be independent of any individual market participant or any one class of participants. . . . A governance structure that includes fair representation of all types of users of the system would help ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner. The ISO's rules of governance [] should prevent control, and appearance of control, of decision-making by any class of participants.[120]

To reinforce the ISO's independent governance, FERC prohibited ISOs and their employees from having any financial interest in the performance of any market participant.[121] The remaining principles define ISO duties,[122] policies,[123] and functions.[124] Taken together, the ISO must have operational control of the transmission network, manage the network pursuant to an OATT, ensure short-term reliability, adopt pricing policies that promote efficient trading, be able to take action consistent with those policies to relieve transmission constraints, make transmission information available, coordinate with neighboring regions, and administer dispute-resolution processes.[125] While FERC said it would evaluate ISO proposals against all eleven principles, it emphasized that "ISO Principles 1 (independence with respect to governance) and 2 (independence with respect to financial interests) are fundamental to ensuring that an ISO is truly independent and would not favor any class of transmission users."[126]

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115. *Id.* at 21,552.
116. 16 U.S.C. § 824(e).
117. Order No. 888, *supra* note 31, at 21,596.
118. Order No. 888-A, *supra* note 107, at 12,317.
119. *Id.* at 12,316.
120. Order No. 888, *supra* note 31, at 21,596.
121. *Id.*
122. *Id.* (discussing principles 3, 4, 5, and 6).
123. *Id.* (discussing principles 7 and 8).
124. *Id.* at 21,596–97 (discussing principles 9, 10, and 11).
125. Order No. 888, *supra* note 31, at 21,596–97.
126. Order No. 888-A, *supra* note 107, at 12,317.

IOU power pool members responded with ISO proposals that reflected their intent to retain control. In the first proceeding about an ISO proposal, FERC rejected proposals filed by PJM IOUs because they reserved board seats for IOUs and provided IOUs with supermajority representation on administrative committees, allowing them to exercise "ultimate control" over the ISO.[127] FERC also rejected the New England Power Pool's (NEPOOL) proposed restructuring because it would similarly provide "a few large utilities [with] excess influence."[128] NEPOOL responded with a new proposal that FERC rejected because it too provided IOUs with control over the organization.[129] FERC also shot down a proposal filed by New York Power Pool IOUs that would have allowed them to "continue to exercise substantial voting power" in their proposed ISO.[130] FERC rejected a subsequent settlement filed by the New York IOUs because the voting structures still "vest[ed] disproportionate authority in the Transmission Providers."[131]

In short, IOUs that dominated tight power pools sought to maintain their control over newly created ISOs. PJM IOUs admitted that they intended to reinforce the status quo. They argued that IOU control over ISO decision making "merely reflects the current fact that the existing [IOU] PJM members have the largest investment" in transmission facilities and "the greatest responsibilities" to captive retail ratepayers.[132] Their governance proposal, they claimed, therefore "equitably reflects the interests" of the IOUs who had agreed to create the ISO.[133] Marrying governance and transmission ownership would effectively recreate the power pool structure and allow IOUs to retain perpetual control over the regional power system. At a time of uncertainty for the industry, the PJM IOUs sought reassurances from FERC that their privileged positions in the industry would be undisturbed by competition for power generation. FERC explicitly declined to endorse any IOU entitlements linked to transmission ownership.

But IOUs pressed their claims in federal court. In approving the PJM ISO tariff, FERC rejected an IOU-filed proposal that would have allowed IOUs to unilaterally file certain transmission tariff amendments, concluding that only the ISO would have authority under FPA section 205 to file changes to transmission rate design and terms of service.[134] The D.C. Circuit rejected FERC's reading of section 205, holding that, as transmission owners, IOUs have filing rights under section 205 that FERC cannot revoke, although the court noted that IOUs may choose

127. *Atlantic City Elec. Co.*, 77 F.E.R.C. ¶ 61,148, at p. 61,574 (1996).

128. *New England Power Pool*, 83 F.E.R.C. ¶ 61,045, at p. 61,260 (1998).

129. *New England Power Pool*, 86 F.E.R.C. ¶ 61,262, at p. 61,965 (1999).

130. *Central Hudson Gas & Electric*, 83 F.E.R.C. ¶ 61,352, at p. 62,409 (1998).

131. *Central Hudson Gas & Electric*, 87 F.E.R.C. ¶ 61,135, at p. 61,540 (1998).

132. Rehearing Request of Nine PJM Utilities, FERC Docket Nos. ER96-2516-002, EC96-28-002, EL96-69-002, ER96-2668-002, EC96-29-002 (Dec. 13, 1996). PJM subsequently filed a new governance proposal, which FERC approved. *Pennsylvania-New Jersey-Maryland Interconnection*, 81 F.E.R.C. ¶ 61,257 (1997).

133. Rehearing Request of Nine PJM Utilities, FERC Docket Nos. ER96-2516-002, EC96-28-002, EL96-69-002, ER96-2668-002, EC96-29-002 (Dec. 13, 1996). *See also Central Hudson Gas & Electric*, 83 F.E.R.C. ¶ 61,352, at p. 62,409 ("As in NEPOOL II, the NYPP members contend that they are entitled to such voting power") (emphasis added).

134. *Pennsylvania-New Jersey-Maryland Interconnection*, 81 F.E.R.C. ¶ 61,257, at p. 62,279.

to voluntarily give up rights by contract.[135] FERC subsequently approved a settlement between PJM IOUs and PJM that allocated section 205 filing rights and provided IOUs with the "exclusive and unilateral right" to make filings about transmission rate design, recovery of transmission revenue requirements, and incentive and performance-based rates.[136] FERC approved similar arrangements for other ISOs and their IOU members,[137] although it warned IOUs that it would monitor how they wield those rights to ensure that they do not do so in a way that compromises ISO independence.[138]

IOUs were also able to gain significant influence over ISO decisionmaking through participation in stakeholder committees. FERC approved two-tier governance structures, with lower-level committees of market participants and an independent board that held final decisionmaking authority.[139] In New York and PJM, a stakeholder committee acts as a gatekeeper for proposed rule changes submitted to the board for its approval.[140] In other regions, stakeholders generally advise the board, although in some regions stakeholders have authority to file proposed rule changes at FERC or protest existing rules.[141] IOUs play prominent roles in these stakeholder committees.

FERC's Open-Access mandate (and subsequent ISO formation orders) nonetheless significantly weakened IOUs' positions. FERC understood that mitigating IOU transmission dominance was necessary to realize its vision of competitive wholesale power markets. While it ordered significant remedies to address IOUs' anti-competitive behavior, FERC still left IOUs at the center of the industry. Functional unbundling sought to rein in IOUs through behavioral rules and tariff terms. For the time being, FERC was reluctant to impose structural reforms that would separate IOUs from transmission operations, planning, and even ownership.

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135. Atlantic City Elec. Co., et al v. FERC, 329 F.3d 1, 9–11 (D.C. Cir. 2002).

136. *Pennsylvania-New Jersey-Maryland Interconnection,* 105 F.E.R.C. ¶ 61,294, at P 11 (2003).

137. *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 F.E.R.C. ¶ 61,380, at P 19 (2005) (citing *ISO New England, Inc.*, 106 F.E.R.C. ¶ 61,280, at P 72 (2004) and *Southwest Power Pool, Inc.*, 106 F.E.R.C. ¶ 61,110, at P 98 (2004)). Note that PJM, ISO-NE, MISO, SPP had already attained RTO status by the time FERC approved these agreements. RTOs are described in the next section.

138. *Pennsylvania-New Jersey-Maryland Interconnection,* 105 F.E.R.C. ¶ 61,294, at P 33. As discussed in Part IV, IOUs would use their filings rights to reinforce their transmission dominance by frustrating FERC's efforts to foster competition in transmission development. *See, e.g.*, *PJM Interconnection*, 147 F.E.R.C. ¶ 61,128, at P 262 (2014) (noting that PJM IOUs have the exclusive right to file changes in cost allocation methods). *See also Monongahela Power Co.*, 162 F.E.R.C. ¶ 61,129, at P 97 (2018) (approving IOUs' local planning processes and their unilateral right to amend those processes). I discuss the connections between transmission cost allocation, local transmission planning, and competition in sections IV.C and D and V.

139. Order No. 2000, *supra* note 36, at pgs. 11, 94.

140. MARK JAMES ET AL., R STREET POLICY STUDY NO. 112: HOW THE RTO STAKEHOLDER PROCESS AFFECTS MARKET EFFICIENCY 8–9 (2017).

141. *Id.* at 4–10.

B. FERC Encourages Further Structural Reforms Under Section 202

Three years after it issued its landmark Open-Access orders, FERC found that there remained "impediments to competition caused by continued discriminatory conduct by transmission owners."[142] To "reduce opportunities for unduly discriminatory conduct" by IOUs[143] and resolve the "engineering and economic inefficiencies inherent in the current [utility-by-utility] operation and expansion of the transmission grid,"[144] FERC encouraged structural reforms. In Order No. 2000, FERC sketched the characteristics and functions of ISO-like Regional Transmission Organizations (RTOs) and required IOUs to consider ceding operational control of their transmission assets to an RTO.[145] FERC hoped that four RTOs would ultimately cover the entire continental United States.[146]

Many in the industry urged FERC to order all IOUs to surrender operational control of their respective transmission assets and join an RTO.[147] As it did in Order No. 888, FERC made findings in Order No. 2000 about undue discrimination that were rooted in each IOU's "incentive and [ ] opportunity to favor their generation interests over those of their competitors."[148] In both orders, this generic finding was backed by specific evidence of utility misconduct,[149] although FERC conceded that some of the evidence amounted to unproven allegations.[150] Nonetheless, in Order No. 888 FERC "conclusively" found that undue discrimination by IOUs was blocking competition, thus meeting the first prong of its dual burden under section 206.[151] FERC's ultimate finding in Order No. 2000 that there remained "continuing opportunity for undue discrimination" was more timid and insufficient, according to FERC, to necessitate any remedy under section 206.[152] Instead, FERC acted under section 202, issuing guidelines about RTOs and committing to review RTO proposals under section 205 pursuant to its guidelines.[153]

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142. Notice of Proposed Rulemaking, *Regional Transmission Organizations,* 64 Fed. Reg. 31,390, at 31,402 (1999) [hereinafter Order No. 2000 NOPR); Rao and Tabors, *supra* note 49, at 1 (saying that IOUs "learned to profit largely within the [open-access] rules" by "effectively foreclosing competition and limiting access to key markets" and that IOUs were able to stretch the rules in part due to the "self-policing nature" of functional unbundling and the difficulty in detecting this behavior). *See also* SMD NOPR, *supra* note 4, at P 333 ("The Commission has found specific instances of abuse by transmission providers regarding the Available Transfer Capability calculation process and delays in the completion of transmission facilities studies. There are obvious incentives for a vertically integrated transmission provider to favor its own generation by delaying facilities studies or manipulating the Available Transfer Capability calculations or postings on its OASIS.").

143. Order No. 2000-A, *Regional Transmission Organizations*, 65 Fed. Reg. 12,088, at 12,091 (2000).

144. Order No. 2000, *supra* note 36, at pg. 13.

145. *Id.* at pg. 3.

146. *PJM Interconnection*, 96 F.E.R.C. ¶ 61,061, at p. 61,226 (2001); *Southern Company Services*, 96 F.E.R.C. ¶ 61,064, at p. 61,280 (2001); *Alliance Companies, et al.*, 97 F.E.R.C. ¶ 61,327, at p. 62,530 (2001) (noting that Midwestern state utility regulators "overwhelmingly prefer a single Midwest RTO).

147. Order No. 2000, *supra* note 36, at pgs. 43–45.

148. *Id.* at pg. 28.

149. *Id.* at pgs. 28-29; Order No. 888, *supra* note 31, at 21,567–58; Order No. 888 NOPR, *supra* note 31, at 17,676, 17,678.

150. Order No. 2000, *supra* note 36, at pgs. 28–29, Order No. 888, *supra* note 31, at 21,568.

151. Order No. 888, *supra* note 31, at 21,569.

152. Order No. 2000, *supra* note 36, at pgs. 29, 60.

153. *Id.* at pg. 62.

As it did in the Open-Access orders, FERC attempted to address IOU control of transmission information. It found that even with its transparency and disclosure rules a "fundamental mistrust of transmission owners" in the industry[154] was impeding market development and adversely affecting reliability.[155] Because information needed for reliable and efficient operations has commercial value,[156] market participants were reluctant to share operational and planning data with IOUs out of suspicion that they might be using that information to gain an advantage.[157] FERC therefore found "a disconnect between electrical flows and information flows" that could have major reliability consequences.[158] Moreover, market participants feared discriminatory curtailment and were skeptical of the accuracy of transmission availability data provided by IOUs. FERC hypothesized that lack of confidence in IOU operations and data raised the risk profile of market transactions, increasing their costs and reducing competition.[159]

For RTOs to become "beneficial platform[s] for both competition and reliability," they needed to see "the big picture by having access to real-time information on conditions and schedules for the entire regional grid."[160] Moreover, RTOs must use that information to resolve reliability issues without regard for the financial interests of any market participant.[161] To be effective, RTOs needed to "be independent in both reality *and perception*"[162] so that they could accumulate accurate information and utilize it to enhance system efficiency rather than enrich particular market participants.

FERC concluded that implementation of Order No. 888 was unlikely to change perceptions about discriminatory IOU behavior and would therefore prove insufficient to facilitate competitive markets, in part because IOU compliance with standards of conduct was difficult to enforce.[163] FERC hoped that RTOs would "eliminat[e] the mistrust in the current grid management"[164] and thereby obviate the need for standards of conduct. To realize this vision of a "better structured market where operational control and responsibility for the transmission system is structurally separated from the merchant generation function of owners of transmission,"[165] the RTO's independence had to extend from its governance to its routine operations.[166]

To further mitigate IOU transmission dominance, FERC supplemented its comparability, transparency, and independence principles with a regionalization

154. Order No. 2000 NOPR, *supra* note 142, at p. 31,402.

155. Order No. 2000, *supra* note 36, at pgs. 27–29.

156. Order No. 2000 NOPR, *supra* note 142, at p. 31,399 ("information that is needed for reliability purposes may also have a commercial value") (citing *Midwest ISO*, 84 F.E.R.C. ¶ 61,231, 62,158–59 (1998)).

157. Order No. 2000, *supra* note 36, at pg. 29.

158. Order No. 2000 NOPR, *supra* note 142, at p. 31,399.

159. Order No. 2000, *supra* note 36, at pg. 29.

160. Order No. 2000 NOPR, *supra* note 142, at p. 31,399.

161. Order No. 2000, *supra* note 36, at pg. 113 (citing *Midwest ISO*, 84 F.E.R.C. 61,231, at p. 62,158).

162. *Id.* at pgs. 79, 84.

163. *Id.* at pgs. 16, 28.

164. *Id.* at pg. 39.

165. *Id.* at pg. 28.

166. *Id.* at pg. 38.

requirement. IOUs had charged transmission customers a separate, additive access charge every time a transmission contract path crosses the boundary of another IOU.[167] This practice, known as rate pancaking, effectively limited the scale of wholesale transactions and resulted in highly concentrated markets.[168] By expanding the geographic scope of trading under a single tariff, pancake-free RTO regions would "reduce the potential for market power abuse,"[169] attract new entrants, enhance liquidity, and allow for more sophisticated transactions.[170]

FERC expected that regional operation would also be technically superior to the status quo.[171] Because power flows do not match transmission "contract paths" and instead follow paths of least electrical resistance, energy traded between two parties may traverse transmission lines owned by numerous utilities.[172] As the volume of trade increases, each utility may find it progressively more challenging to estimate available transmission capacity that it must make available for wholesale trades under FERC's Open-Access orders.[173] Moreover, an overloaded line may raise energy prices by preventing low-cost power from reaching consumers.[174] This "congestion"[175] had been addressed by each utility without assessing costs imposed on other transmission users, raising the suspicion that the utility was acting in its own interests to the detriment of consumers.[176] With greater visibility

167. Order No. 2000 NOPR, *supra* note 142, at p. 31,401.

168. *Id.*

169. Order No. 2000, *supra* note 36, at pg. 39.

170. *Id.*

171. Order No. 2000 NOPR, *supra* note 142, at pp. 31,408–09 (explaining that because electric power traverses transmission lines according to physical laws, power injected from a generator connected to a utility's system will affect flows on infrastructure owned by other utilities. These so-called parallel flows complicate each utility's calculation of transmission capacity available for wholesale sales, which can lead to disputes about compensation and result in curtailments); Transmission Task Force, *supra* note 87, at 63–66 (reporting that in some regions as much as 50% of a power travels hundreds of miles from the contract path across lines of uncompensated utilities and that the remedy is typically uneconomic curtailment).

172. Transmission Task Force, *supra* note 87, at 64.

173. Order No. 2000 NOPR, *supra* note 142, at pp. 31,399–400.

174. Richard J. Pierce, *The State of the Transition to Competitive Markets in Natural Gas and Electricity,* 15 ENERGY L. J. 323, 339–340 (1993) (citing various papers by William W. Hogan).

175. Congestion is "the inability to inject and withdraw additional energy at particular locations in the network due to the fact that the injections and withdrawals would cause power flows over a specific transmission facility to violate the reliability limits for that facility." Notice of Proposed Rulemaking, *Long-Term Firm Transmission Rights in Organized Markets*, Notice of Proposed Rulemaking, 114 F.E.R.C. ¶ 61,097, at P 14 (2006). A Department of Energy report explains that congestion:

> occurs when there is not enough transmission capability to support all requests for transmission services, and in order to ensure reliability, [] system operators must re-dispatch generation or, in the limit, deny some of these requests to prevent [] lines from becoming overloaded. In other words, transmission congestion . . . refers to requests for deliveries (transactions) that cannot be physically implemented as requested.

Bernard C. Lesieutre and Joseph H. Eto, *Electricity Transmission Congestion Costs: A Review of Recent Report*, ERNEST ORLANDO LAWRENCE BERKELEY NAT'L LAB (Oct. 2003), https://www.energy.gov/sites/prod/files/oeprod/DocumentsandMedia/review_of_congestion_costs_october_03.pdf.

176. Order No. 2000 NOPR, *supra* note 142, at p. 31,400.

into network conditions than any single IOU,[177] an RTO would be better able to publish accurate transmission information and set efficient prices.

Two years after it issued Order No. 2000, FERC proposed its so-called Standard Market Design (SMD) order, which would have required all IOUs to place their transmission assets under the control of an independent entity, such as an RTO.[178] FERC capitulated to political pressure and terminated the SMD proceeding three years after it released the proposal.[179] Today, separating transmission operations from transmission ownership (known as operational unbundling) remains optional. As a result of FERC's failure to finalize the denouement of its Restructuring Trilogy (SMD along with Orders Nos. 888 and 2000), the industry is split along geographic lines. In the Eastern Interconnection, nearly all IOUs outside of the Southeast are RTO members.[180] In the West, only California IOUs have ceded control of their transmission assets to an independent entity. Of the four multi-state RTOs,[181] MISO is the only one that was not built upon the ashes of an IOU power pool.

Order No. 2000 and the SMD NOPR were premised on a fundamental mismatch between IOUs' unearned advantages and FERC's vision for the power sector's future. State-sanctioned IOUs were the dominant industry actor in the twentieth century, but FERC saw that their continued dominance was incompatible with a competitive power generation sector. FERC hoped that independent interstate entities — directly under FERC's control — would be the key to unlocking a more dynamic and innovative power industry in the twenty-first century.

IV. IOUS EXPLOIT THEIR STATE-GRANTED SERVICE TERRITORIES TO AVOID FERC-MANDATED COMPETITIVE TRANSMISSION DEVELOPMENT PROCESSES

In 2007, FERC applied its comparability and information transparency principles to IOU transmission planning processes. With this move into transmission planning, FERC intended to shine a light on transmission development decisions that had long been internal IOU matters. Four years later, in Order No. 1000, FERC required IOUs to engage in regional planning with the goal of meeting transmission needs across service territories more efficiently. Under Order No. 1000, regional planners must consider non-IOU developers on a non-discriminatory basis for project development opportunities. With these two reforms, FERC formalized project development processes and opened opportunities for non-IOU entities to finance projects through cost-of-service rates. IOUs persistently objected through legal processes and informal practices. FERC has often sided with

177. *Id.* ("a regional organization would have accurate and reliable information about existing and possible future conditions on the grid. Such information is generally not available to individual transmission providers.")

178. *See* SMD NOPR, *supra* note 4, at P 100.

179. FERC Docket No. RM01-12, Order Terminating Proceeding (July 19, 2005).

180. Part of Emera Maine's service territory is not served by ISO-NE. Louisville Gas & Electric and Kentucky Utilities withdrew from MISO in 2006. Both utilities are subsidiaries of PPL.

181. NYISO and CAISO are not RTOs due to their single state coverage. *New York ISO, et al.*, 96 F.E.R.C. ¶ 61,059 (2001) (rejecting New York ISO Order No. 2000 compliance filing); *California Indep. Sys. Operator, et al.*, 112 F.E.R.C. ¶ 61,155 (2005) (terminating proceeding about whether CAISO meets Order No. 2000 requirements).

IOUs and failed to follow through on the Order's lofty goal of bringing competitive discipline to transmission development. IOUs continue to dominate transmission development by focusing on non-competitive projects within their state-granted service territories.

A. Connecting Transmission Planning and Transmission Dominance

More than half a million miles of transmission lines crisscross the continental United States.[182] Wires, poles, towers, substations, and other system components have a useful life of several decades,[183] and the rights-of-way may host generations of transmission infrastructure. Additions to the interconnected interstate system affect the "vast pool of energy"[184] that charges the network and flows pursuant to the laws of physics. Because changes to the network directly affect energy flows across the network, proposed additions must be analyzed to ensure they do not disrupt reliable operations. Beyond these technical considerations, the reach and design of the network have vast economic and environmental implications. The network's reach shapes the mix of resources that supply power, potentially unlocking location-constrained renewable resources, such as hydro, wind, and solar, or connecting to fossil resources, such as coal mines and natural gas shale plays. In addition, transmission availability can influence industrial and population development patterns.

Transmission expansion must be thoughtfully planned due to its direct effects on industry operations as well as the broader societal consequences of extending the interstate network. In this section, I begin by outlining the goals of transmission planning and then justify the necessity of strong oversight. The ability of an IOU to unilaterally plan network expansion can reinforce and perpetuate its transmission dominance. In Part III, I summarized how FERC separated IOU transmission ownership from operational control by imposing functional unbundling and encouraging structural separation through operational unbundling. In this Part, I explain why it is imperative that FERC separate ownership from planning.

Planning for system expansion was historically conducted on a utility-by-utility basis.[185] Transmission expansion connected to newly constructed generation or to neighboring systems.[186] Once the industry began to formalize reliability

182. There are approximately 600,000 miles of transmission line miles in the United States. DEP'T OF ENERGY, QUADRENNIAL ENERGY REV. 3–4 (Apr. 2015), https://www.energy.gov/sites/prod/files/2015/04/f22/QER_Ch3.pdf. About 240,000 miles of those are 230kV or above and considered "high voltage." EDISON ELEC. INST., ISSUES AND POLICY: TRANSMISSION, https://www.eei.org/issuesandpolicy/transmission/Pages/default.aspx.

183. Jeff Hein, et al., *Transmission Planning Process and Opportunities for Utility-Scale Solar Engagement within the Western Electricity Coordinating Council*, NAT'L RENEWABLE ENERGY LAB., at 7 (Nov. 2011) (noting that bulk power infrastructure has a typical lifespan of 40 to 60 years).

184. New York v. FERC, 535 U.S. 1, 7 (2002).

185. SMD NOPR, *supra* note 4, at P 336 ("Transmission planning and expansion have generally been performed for a single control area rather than on a regional basis. This yields sub-optimal solutions . . . ").

186. 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-16-3 (noting that "many new transmission facilities are associated with new generating plant additions"); Richard P. Bonnifield & Ronald L. Drewnowski, *Transmission at a Crossroads*, 21 ENERGY L. J. 447, 461 (2000) ("It was the generation prudence review by the state utility commissions that justified the investment in transmission expansion."); James J. Hoecker and Douglas W. Smith, *Regulatory Federalism and Development of Electric Transmission: A Brewing Storm?* 35 ENERGY

standards, transmission planners typically categorized projects as 'reliability' or 'economic,' to distinguish between projects aimed at complying with reliability criteria and expansions that lower production costs.[187] Regional economic dispatch, pioneered by power pools and furthered by the development of ISOs and RTOs, enhanced opportunities for transmission expansion designed to reduce transmission "congestion."[188] Building more transmission in the right locations can relieve congestion that that prevents low-cost power from reaching consumers, thereby reducing regional costs and improving the power system's efficiency.

Transmission expansion can also facilitate achievement of public policy objectives and other goals that are difficult to monetize.[189] Lines built to connect to areas with high wind or solar potential can unlock energy resources that meet state renewable energy mandates or federal air quality requirements. New infrastructure might also contribute to a system's fuel diversity, mitigating the effects of fuel price increases or shortages.[190] New transmission can also "strengthen and increase the flexibility of the overall transmission network," which can "create real

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L. J. 71, 75 (2014); Stalon and Lock, *supra* note 80, at 460 (observing that "states traditionally have taken relatively little interest in transmission facility planning. . . .[and] additions typically have been viewed by utility planners and state regulators as adjuncts to the much larger generation investments"); Vikram S. Budhraja et al., *Improving Electricity Resource Planning Processes by Considering the Strategic Benefits of Transmission*, 22 ELEC. J. 54 (Mar. 2009); Joseph Eto and Bernard Lesieutre, The Consortium for Electric Reliability Technology Solutions, LAWRENCE BERKELEY NAT'L LAB., *Transmission-Planning Research & Development Scoping Project*, at 3 (July 2004), https://eta-publications.lbl.gov/sites/default/files/certs-trans-planning-research.pdf [hereinafter Scoping Project]:

> In the past, utilities planned transmission jointly with generation. The purpose of transmission was to bring power from distant generation sources to meet local demand. Because the planning was conducted by vertically integrated firms, it was straightforward to trade off generation and transmission costs, i.e., the added expense of building transmission to access cheaper sources of remote generation versus the higher cost of building and operating generation closer to load.

Eric Hirst and Brendan Kirby, *Transmission Planning and the Need for New Capacity*, National Transmission Grid Study Issue Paper, at D-6, https://eta-publications.lbl.gov/sites/default/files/trans-planning-new-capacity.pdf [hereinafter Planning and Need].

187. Planning and Need, *supra* note 186, at D-18 (stating that "industry experts believe that the distinction between reliability and commerce in transmission planning is increasingly irrelevant" because "reliability problems are also commercial problems" but others find the distinction relevant in part because it might inform who pays for the solution).

188. For an explanation of transmission congestion, *see* note 175.

189. Order No. 1000, 136 F.E.R.C. ¶ 61,051 (2011) [hereinafter Order No. 1000]; New York Independent System Operator, *Transmission Expansion in New York State: A New York ISO White Paper*, 4-1 (Nov. 2008) (filed in FERC Docket No. 0A08-52, Attachment A to Answer of New York Regional Interconnect, Motions of New York Independent System Operator and the Companies, Dec. 16, 2008) [hereinafter NYISO White Paper]:

> [I]n the RTO/ISO era, transmission investment is driven primarily to maintain and enhance reliability, with some consideration of economic and market efficiency purposes. Looking forward, it appears that transmission may need to be planned to meet objectives other than reliability and economics – namely, public policy objectives driven by environmental and fuel diversity concerns. The incorporation of desired attributes other than system reliability and market economics represents a significant change for the transmission industry.

190. *See, e.g., New England Power Pool Participants, et al.* 52 F.P.C. at p. 410 (1974) (discussing a "coal-by-wire" program that required utilities to transmit coal-fired power to New England utilities, which relied on oil power. While this short-term program did not include construction of new transmission, it was only possible because the utility systems were already interconnected); NYISO White Paper, *supra* note 189, at 4-5 ("Transmission can provide significant fuel diversity benefits to this region . . . .").

options to use the transmission system in ways that were not originally envisioned."[191] Unexpected benefits can eclipse the original purposes the transmission expansion was intended to serve by enabling the network to adjust to unanticipated fuel price changes, economic volatility, new environmental requirements, outages, and natural disasters.[192]

Transmission planning aims to incorporate information about system conditions, expected load growth, anticipated generation expansion, regulatory requirements, and available technologies. Planners use computer models to understand system responses to various expansion options.[193] Model results, as well as information about project costs, environmental effects, and regulatory requirements, inform planners' assessments of different projects.[194] Planners also consider alternatives, such as demand-side technologies that can reduce flows of energy on the interstate network and thereby obviate the need for additional infrastructure.[195] Ultimately, planners assess the tradeoffs among various projects and create a plan for expansion. Planning is a "fundamentally difficult problem because transmission lines are costly, long-lived assets that must be built despite considerable uncertainty about future technology, policies, demand, and supply."[196]

In the industry's earlier eras, vertically integrated IOUs retained nearly all of the relevant planning information.[197] An IOU not only owned and operated the transmission network and all (or nearly all) of the generation within its state-

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191. U.S. DEP'T OF ENERGY, NATIONAL ELECTRIC TRANSMISSION CONGESTION STUDY, at 11 (Sept. 2015), https://www.energy.gov/sites/prod/files/2015/09/f26/2015%20National%20Electric%20Transmission%20Congestion%20Study_0.pdf [hereinafter DOE Congestion Study]; Budhraja, *supra* note 186, at 54 (finding that analytical methods used in planning processes "do not capture the many strategic benefits of high-voltage electricity transmission projects, such as those resulting from the long life of projects, dynamic changes to the system, access to diverse fuels, mitigation of risks as a form of insurance against extreme events, and advancement of public policy goals").

192. DOE Congestion Study, *supra* note 191, at 11; 1964 NATIONAL POWER SURVEY, *supra* note 44, at 211 ("The value of a strong transmission network lies in the flexibility it offers for meeting large variations in loads . . . and the ability to share diversities and reserves. . . . An adequate network will facilitate the adjustment that invariably is required for miscalculations of load growth, emergencies, or sudden changes in major loads . . . ."); Planning and Need, *supra* note 186, at D-2.

193. Planning and Need, *supra* note 186, at D-2; Scoping Project, *supra* note 186, at 8.

194. Planning and Need, *supra* note 186, at D-2.

195. Shelley Welton, *Non-Transmission Alternatives*, 39 HARVARD ENVTL. L. REV. 457, 464–470 (2015).

196. Comment of the Staff of the Federal Trade Commission, FERC Docket No. AD12-9 (June 14, 2009). As just one example, the magnitudes of cost shifts and efficiency gains due to congestion relief are uncertain. *See, e.g.,* Planning and Need, *supra* note 186, at D-19 (stating that uncertainties relate to load growth, price responsiveness of load, fuel costs, additions and retirements of generation, exercise of market power by generators, and transmission pricing); *id.* at D-9 (showing congestion costs in New England under different assumptions about these factors); NYISO White Paper, *supra* note 189, at 5-2 ("Large transmission projects can shift bidding behavior, making predictions about price impacts difficult. Over the longer term, the cost and benefits identified with a transmission expansion can shift due to" several factors).

197. Planning and Need, *supra* note 186, at D-6; Joseph H. Eto, *Planning Electric Transmission Lines: A Review of Recent Regional Transmission Plans*, LAWRENCE BERKELEY NAT'L LAB, at 16 (Sept. 2016) https://www.energy.gov/sites/prod/files/2017/01/f34/Planning%20Electric%20Transmission%20Lines--A%20 Review%20of%20Recent%20Regional%20Transmission%20Plans.pdf [hereinafter Review of Recent Regional Plans] ("Prior to the formation of ISO/RTOs, the existing transmission owners were, in effect, the sole or primary entities responsible for developing projects within their footprints and for coordinating with one another . . . to develop projects that involved more than one entity's system.").

granted service territory, it was also the authoritative source for generation and load forecasts, transmission cost projections, and assessments of available technologies. IOUs planned for themselves — to connect to their own power plants (or plants they had contracted with) and to their own wholesale customers and retail ratepayers. IOUs built planned projects themselves, financing expansion through cost-of-service rates paid by captive consumers.

Following the Open-Access orders, IOUs lost their monopolies on planning-relevant information. Actions by non-IOUs, such as independent generators that intended to develop new projects and TDUs that were no longer captive IOU customers, could significantly affect transmission needs. Including non-IOUs in transmission planning was necessary to ensure that assessments of system needs matched market participants' plans and reflected viable options. Input from state regulators, ratepayer advocates, environmental groups, and other stakeholders may help gauge whether particular projects might receive siting permission and be relevant to assessing tradeoffs among planning criteria. As examples, upgrades that enhance reliability may raise rates, projects that bring regional benefits may have adverse local environmental impacts, and congestion mitigation can cause certain parties to lose money.[198]

Weighing these tradeoffs and incorporating information from stakeholders that may have opposing interests is complex. Because IOUs are themselves interested parties and have incentives that diverge from their customers, competitors, and policymakers, they are not capable of acting as neutral arbiters in transmission planning processes. Like any profit-driven company, IOUs seek to use their strategic advantages to advance their own interests. In a complicated transmission planning process, an IOU might use its informational advantages and position as the dominant local transmission owner and developer to block projects that harm its interests or to advance projects that benefit it financially but harm others.

For example, the American Antitrust Institute (AAI) has hypothesized several scenarios where an IOU might block transmission developments that would benefit ratepayers or the IOU's competitors. A congestion-relieving project, even one that would reduce rates paid by its own captive consumers, might harm the IOU if it owns generation that benefits from the congestion or holds financial instruments tied to the congestion.[199] Similarly, an IOU might have an incentive to

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198. U.S. DEP'T OF ENERGY, NATIONAL TRANSMISSION GRID STUDY, at 52 (May 2002), https://eta-publications.lbl.gov/sites/default/files/doe-natl-trans-grid-study.pdf [hereinafter National Grid Study] ("This input is especially needed to support the identification and assessment of tradeoffs among planning criteria"); *Id.* ("Access to operational data is essential to allow market participants to formulate and evaluate viable proposals"); Planning and Need, *supra* note 186, at D-20 (explaining that consumers on the low-cost side of the transmission constraint and generators on the high-cost side of the constraint may lose money from congestion-relief).

199. Amicus Brief of the American Antitrust Institute in Support of Petitioner, *New York Regional Interconnect v. FERC*, Docket 09-1309, at 16 (D.C. Cir. Jul. 29, 2010) [hereinafter AAI Brief]; *see also PJM Interconnection,* 124 F.E.R.C. ¶ 61,187 (2008) (rejecting notion that a planning process must allow an IOU to veto a project that is cost beneficial from the regional perspective but harmful to the IOU's own financial interest); *New York Indep. Sys. Operator*, 129 F.E.R.C. 61,045 (2009) (Moeller, dissenting):

> Under the NYISO's supermajority voting provision, certain beneficiaries of the proposed project may find it in their interest to vote against a transmission line in order to preserve or increase their own

block transmission projects that would enable competing retailers to access low-cost generation that the IOU may already be able to access through a long-term agreement.[200] FERC has developed similar hypotheses.[201]

Apart from their interests in wholesale power, IOUs might also seek to block projects in order to maintain their monopolies over local transmission. A New York ISO white paper posits that "utilities will protect their franchise areas, a valuable and exclusive asset, and are loathe to allow competitors' [transmission] projects through their areas without some control and participation."[202] AAI claims that because the development of one transmission project may foreclose alternatives, an IOU may attempt to block a competing project in order to boost its own alternative.[203] IOUs also compete with non-IOU developers in "more subtle ways" by providing "yardstick competition."[204] A non-IOU project that is less expensive than IOU projects may put pressure on a utility by alerting regulators that the IOU is not the least-expensive transmission developer.[205]

Oversight should restrain IOUs' incentives and abilities to use their informational and regulatory advantages to prioritize their own financial goals. As I describe in Part IV.C, FERC has thus far adopted two approaches. For all transmission planning, it has instituted procedural reforms that aim to counteract IOUs' advantages linked to their historic monopolies on transmission development within their state-granted service territories. For planning regionally beneficial projects whose costs are borne by more than one transmission owner, FERC has partially displaced the IOU as the planning decision maker. Where RTOs operate the network, they are also responsible for developing regional expansion plans. Elsewhere, IOU-controlled organizations generate regional plans.

As I describe below, FERC's transmission planning reforms follow numerous efforts to encourage IOUs, pursuant to section 202, to coordinate their planning. Ultimately, FERC shifted to a mandatory approach under section 206, linking its reforms to its duty to ensure just and reasonable and not unduly discriminatory rates. FERC justified its planning rules by pointing to its well-established conclusion that IOUs will act in their own self-interest to the detriment of consumers and competitors if left unchecked. I see another reason for robust FERC oversight of planning.

> revenues or profits even if the project would yield net benefits in New York. For instance, a Transmission Owner (TO) holding valuable Transmission Congestion Contracts may choose not to support a congestion-reducing project because it financially benefits from existing levels of congestion.

Timothy J. Brennan, *Resources for the Future, "Alleged Transmission Undersupply: Is Restructuring the Cure or the Cause?"* at 6 (Oct. 2005), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=851804 (noting that financial transmission rights may vest holders with "an interest in limiting [transmission] capacity to profit from congestion rents").

200. AAI Brief, *supra* note 199, at 18.

201. Order No. 890, *Preventing Undue Discrimination and Preference in Transmission Service*, 118 F.E.R.C. ¶ 61,119, at PP 422–24 (2007) [hereinafter Order No. 890].

202. NYISO White Paper, *supra* note 189, at 4–7; 1970 NATIONAL POWER SURVEY, *supra* note 44, at I-17-25 ("Joint ownership of transmission systems is less widespread than jointly owned generation because most electric utilities prefer to own all transmission facilities within their own service area.").

203. AAI Brief, *supra* note 199, at 20.

204. *Id.*

205. *Id.* at 20–21.

For more than a century, IOUs have enjoyed transmission monopolies within their state-granted service territories. A fundamental pillar of the IOU business model is to build more transmission in their exclusive retail footprints.[206] As their local networks age, IOUs may find that the simplest paths forward for maintaining reliability, as well as the easiest for supporting their financial returns, are in replacing aging infrastructure or supplementing it with new or reconductored local lines.[207] Rebuilding twentieth century infrastructure may be a viable solution for keeping the lights on, but it neglects the innovative potential of twenty-first century technologies and is unlikely to be the most cost-effective solution for decarbonizing the nation's power networks.

IOUs are generally incentivized to disfavor new technologies, including demand-side solutions and high-tech operational practices, that might obviate the need for additional transmission infrastructure,[208] in part because they are not as predictably profitable under the cost-of-service business model.[209] Consideration of twenty-first century technologies, ranging from distributed storage to software optimization tools, should be a fundamental component of transmission planning. Advancing this non-traditional infrastructure may require new planning approaches that seem to me unlikely to come from local monopolists. In addition, as the resource mix evolves, new types of transmission projects — regional and perhaps even continental in scale, and utilizing direct current technology — may be the optimal means for cost-effectively integrating wind and solar generation.[210] IOUs' incentives to prioritize development in their state-protected service territo-

206. AAI Brief, *supra* note 199, at 21.

207. *Id.*

208. Welton, *supra* note 195, at 464–70, 486–504 (2015) (describing consumer-facing technologies collectively referred to as "non-transmission alternatives"); T. Bruce Tsuchida & Rob Gramlich, *Improving Transmission Operation with Advanced Technologies: A Review of Deployment Experience and Analysis of Incentives*, at 6–15 (June 24, 2019), https://gridprogress.files.wordpress.com/2019/06/brattle-grid-strategies-paper-improvingtransmissionoperationwithadvancedtechnologies.pdf (outlining operational practices enabled by communications and computing technologies that can increase transmission transfer capability).

209. Welton, *supra* note 195, at 486–504; Tsuchida & Gramlich, *supra* note 208, at 20–22; Rob Gramlich, WATT Coalition, *Bringing the Grid to Life: White Paper on Benefits to Customers of Transmission Management Technologies*, at 7–9 (Mar. 2018), https://gridprogress.files.wordpress.com/2019/08/bringing-the-grid-to-life-white-paper-on-the-benefits-to-customers-of-transmission-management-technologies.pdf (explaining that investment decisions are infected by "capital bias" that makes operational enhancements unattractive).

210. Numerous studies have found that significant investments in transmission are needed to cost-effectively integrate zero emission resources. *See, e.g.*, Jesse D. Jenkins, Max Luke, and Samuel Thernstrom, *Getting to Zero Carbon Emissions in the Electric Power Sector*, 2 JOULE (Issue 12) 2487, 2506, 2508 (Dec. 19, 2018) (reviewing forty deep decarbonization scenarios, noting that several scenarios "envision tens of thousands of miles of new high-voltage direct-current transmission linking all regions in the United States," and summarizing that "all scenarios benefit from cost-effective demand flexibility and transmission expansion"); Patrick R. Brown & Audun Botterud, *The Value of Inter-Regional Coordination and Transmission in Decarbonizing the US Electricity System*, 5 JOULE (Issue 1) 115 (Jan. 20, 2020) ("using a co-optimized capacity-planning and dispatch model over seven years of hourly operation [and] show[ing] that inter-state coordination and transmission expansion reduce[s] the system cost of electricity in a 100%-renewable US power system by 46% compared with a state-by-state approach"); Armando L. Figueroa-Acevedo, Jordan Bakke, Harvey Scribner, Ali Ardakani, Hussam Nosair, Abhinav Venkatraman, James McCalley, Aaron Bloom, Dale Osborn, P. Caspary, and James Okullo, *Design and Valuation of High-Capacity HVDC Macrogrid Transmission for the Continental US*, IEEE TRANSACTIONS ON POWER SYSTEMS (2020).

ries bias them against large-scale projects, particularly high-efficiency direct current lines that don't neatly integrate with existing alternating current infrastructure. Although a hypothetical "Supergrid," or "Smartgrid" is not my focus, it is evident that the current IOU-centric development paradigm is incompatible with construction of continental-scale transmission and deployment of technologies that might obviate the need for IOUs' local transmission spending.

B. FERC Encourages Voluntary Planning and Merchant Transmission

By the 1960s, FERC recognized that encouraging joint planning was a key element of its duty under section 202.[211] At the time, most coordinated planning centered on generation,[212] a focus that tracked IOUs' investments and cost-recovery priorities.[213] One notable exception was planning for seasonal energy exchanges, which often required long-distance transmission.[214] While FERC approved numerous coordination agreements, many of which included provisions about joint transmission planning, its orders approving those agreements do not discuss the provisions that outline transmission planning procedures.[215]

As FERC began exploring how to facilitate competitive power markets, it understood that IOU transmission planning could be hindering wholesale market

211. *See, e.g.,* 1964 NATIONAL POWER SURVEY, *supra* note 44, at 1 ("The Survey is thus encouraging the industry to initiate broader regional and interregional planning. . . . In short, the Survey was conducted by the Commission as the most effective means of carrying out the provisions of section 202(a)."); *Pacific Gas & Elec. Co.*, 49 F.P.C. 1103, at p. 1105 (1974) (characterizing its "policies and practices" under 202(a) as "designed to afford all electric systems opportunity for coordination regional bulk power supply planning"); *Reliability and Adequacy of Electric Service – Reporting Data*, 56 F.P.C. 3547, at p. 3548 (1976) ("Long-range planning is an indispensable element to the accomplishment of the objective of section 202(a)."). *But see*, Order No. 1000, *supra* note 189, at PP 101, 105 (rejecting the focus on coordination in FERC's understanding of 202(a)); Order No. 1000-A, *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 139 F.E.R.C. ¶ 61,132, at PP 123−52 (2012) [hereinafter Order No.1000-A].

212. 1979 NATIONAL POWER GRID STUDY, *supra* note 51, at 42 (observing that prior to the mid-1960s capacity planning "was a relatively simple and straightforward task. New generating and transmission facilities would be ordered based on projected load growth, and new fossil-fired plants were brought online three to five years after the decision to order them."); *Re Western Mass. Elec. Co.*, 39 F.P.C. 723, at p. 736 (1968) (noting that the "stated purposes" of regional council of IOUs included "to promote in New England the continued coordination of economic operation of existing generating facilities [and] to promote over-all planning for the integrated and balanced expansion of new generating plants").

213. In 1980, for example, generation accounted for about 50% of IOU gross plant in service and 80% of annual operation and maintenance expenses. JOSKOW & SCHMALENSEE, *supra* note 16, at 46 (citing U.S. Department of Energy, Energy Information Administration, Statistics of Privately Owned Electric Utilities in the United States, 1980 Annual). Today, across the industry, transmission accounts for less than 20% of annual IOU capital spending. EDISON ELEC. INST., ELECTRIC POWER INDUSTRY OUTLOOK, at 23 (Feb. 5, 2020, https://www.eei.org/issuesandpolicy/finance/wsb/Documents/2020_Wall_Street_Final_Slides_Web.pdf).

214. For example, IOUs in the Southwest Power Pool region built 1,140 miles of high-voltage lines to enable exchanges with the Tennessee Valley Authority that parties agreed to in 1964. Power Pooling in the U.S., *supra* note 16, at 125. The Pacific Northwest-Southwest Intertie, with a delivery capacity of 1.4 GW, was developed to market surplus hydro from the northwest and deliver California thermal energy to the northwest during low hydro periods. *Id.* at 139, 151. In the upper Midwest, utilities built a high-voltage network linking major load areas in ten states. *Mid-Continent Area Power Pool*, 58 F.P.C. 2622, at p. 2646 (1977).

215. *See, e.g., New England Power Pool Agreement*, 48 F.P.C. 538, at pp. 546-49 (1972). *Mid-Continent Area Power Pool Agreement,* 48 F.P.C. 607 (1972). *See also Boston Edison Co.*, 44 F.E.R.C. ¶ 61,199, at p. 61,707−08 (1988) (noting that NEPOOL participants coordinate transmission planning but that IOUs build transmission to serve their own loads).

development.[216] To address this barrier, in 1993, FERC issued a policy statement that "encouraged" utilities to develop Regional Transmission Groups (RTGs).[217] FERC hoped that RTGs would be "collaborative mechanisms"[218] for utilities and their wholesale customers to "coordinate their transmission planning more effectively" and cooperate on certain operational matters.[219] Seeking to encourage RTG participation, FERC provided "considerable flexibility" in the content of RTG agreements but outlined seven necessary components.[220] With regard to planning, an RTG agreement must facilitate "the development of a coordinated transmission plan on a regional basis and the sharing of transmission planning information" that accounts for the needs of non-members and interconnected regions.[221]

Shortly thereafter, FERC's Open-Access orders overtook its push for RTG formation.[222] Nonetheless, the RTG guidelines mark a turning point in FERC's approach to encouraging coordination. Rather than relying on ad-hoc utility arrangements, FERC defined a form of coordination that it would deem acceptable and then evaluated IOU filings against its guidelines.[223] Because FERC determined that RTG agreements would affect or relate to transmission rates, FERC reviewed proposed arrangements under section 205 standards.[224] If a proposed plan failed to conform to FERC's guidelines, FERC would reject it as unjust and unreasonable or unduly discriminatory. FERC would later replicate this approach with its ISO and RTO guidance.

Order No. 888 changed little about FERC's approach to transmission planning. FERC acknowledged that IOUs had generally not allowed their wholesale customers to participate in planning processes,[225] but it rejected imposing any planning mandate as beyond the scope of the proceeding.[226] Instead, FERC "encouraged" utilities to engage in joint planning[227] or to join an ISO, RTG, or "other

216. Transmission Task Force, *supra* note 87, at 173–74 (noting that that in the absence of any federal policy IOUs might "restrict the available capacity as a way to increase the price of either short-term or long-term service or as a way to reduce service options of competitive buyers and sellers"); *Id.* (noting that state regulators could allocate benefits of IOU market power between the utility and its captive ratepayers, to the detriment of competitors and out-of-state consumers). *See also* Stalon & Lock, *supra* note 80, at 450 (noting that with greater wholesale competition state utility regulators "were less able to use their distribution monopoly power to achieve various social objectives").

217. FERC, *Policy Statement Regarding Regional Transmission Groups*, 58 Fed. Reg. 41,626, 41,627–28 (Aug. 5, 1993) [hereinafter RTG Policy Statement] (noting that while RTGs were proposed in Congress during debates about the Energy Policy Act of 1992, those provisions were not enacted).

218. *Id.* at 41,631.

219. *Id.* at 41,628.

220. *Id.* at 41,629.

221. *Id.* at 41,630. In proceedings about utility proposals, FERC clarified that "coordinating" planning required more than merely compiling utility plans, *Southwest Reg'l Transmission Ass'n*, 69 F.E.R.C. ¶ 61,100, at p. 61,399–400 (1994); *Western Reg'l Transmission Ass'n*, 69 F.E.R.C. 61,381, and reiterated that the "primary purpose" of RTG planning is to "negotiate and carry out a single unified" regional transmission plan.

222. FERC approved only three RTGs. *Northwest Reg'l Transmission Ass'n*, 71 F.E.R.C. ¶ 61,397 (1995).

223. RTG Policy Statement, *supra* note 217, at 41,631.

224. *Id*. at 41,632.

225. Order No. 888-A, *supra* note 107, at 12,330.

226. *Id.* at 12,352.

227. *Id.*

regional entity that has an open planning process."[228] FERC expected ISOs to "have a clear and prominent role in the transmission expansion process,"[229] that included conducting the necessary studies to identify the need for transmission expansion,[230] but it approved processes that left IOUs with considerable control.[231] FERC overlooked arguments that an IOU-dependent planning process would enable the exercise of "dynamic market power" that arises from each IOU's ability to manipulate transmission expansion to benefit its own power marketing interests.[232] FERC also rejected proposals to require ISOs to open all transmission expansion projects to competitive bidding.[233]

In Order No. 2000, FERC purported to build on the "prominent role" it envisions for ISOs and RTGs.[234] It required RTOs to have the "ultimate responsibility for both transmission planning and expansion," and stated that independence from market participants is a "necessary condition" for effective planning.[235] But transmission planning was clearly not FERC's priority in Order No. 2000. It allowed RTO proposals to punt on the details of transmission planning, requiring only that filings include "specified milestones" to performing this function within three years of initial operation.[236]

In orders reviewing RTO proposals, FERC aspired to empower RTOs in their planning processes. It said that RTOs must "independently oversee the regional transmission plan and solely determine the priority of transmission planning projects."[237] FERC rejected the notion that RTO planning should be merely "a collection of traditional expansion plans developed by individual [transmission owners] and assembled by the RTO after confirming that they serve reliability

228. *Id.* at 12,330.

229. *Pacific Gas & Elec.*, 77 F.E.R.C. ¶ 61,204, at p. 61,835 (1996).

230. Order No. 888, *supra* note 31, at 21,596 (requiring ISO or RTG to "conduct such studies as may be necessary to identify . . . appropriate expansion"); Order No. 888-A, *supra* note 107, at 12,318.

231. *PJM Interconnection*, 81 F.E.R.C. ¶ 61,257, at p. 62,275 (1997) (approving an ostensibly ISO-led planning process that relied on IOUs to supply staff, data, and technical systems).

232. Sacramento Public Utility District, Testimony of Dennis W. Carlton, FERC Docket No. ER96-1663, Sep. 13, 1996, at 5–6 (testifying that the IOUs focus on "static market power" and "fail to analyze whether they will have an economic incentive" and an "ability" to "block or delay economically efficient [transmission] expansion" and concluding that their ISO governance proposal would allow them to do so); Sacramento Public Utility District, Testimony of Gustavo E. Bamberger, FERC Docket No. ER96-1663, Jan. 17, 1997, at 5–6:

> It is important to remember that the logic of establishing the ISO reflects an attempt to 'delink' the ownership of generation and transmission assets. If that is the goal of the ISO in a static environment (i.e., given the current capacity and location of transmission assets), it seems reasonable to pursue that goal in a dynamic sense as well. That is, if one of the reasons for establishing an ISO is to remove or reduce a transmission owner's ability to favor its own generation today, it seems reasonable to structure the ISO in a way that removes or reduces the same transmission owner's ability to affect transmission grid expansion decisions in ways that will benefit its own generation in the future. Thus, I am in favor of allowing the ISO to play an active and substantial role in transmission grid expansion decisions.

233. *Pacific Gas & Elec.,* 80 F.E.R.C. ¶ 61,128, at p. 61,433 (1997).

234. *Pacific Gas & Elec.*, 77 F.E.R.C. ¶ 61,204, at p. 61,835; Order No. 2000, *supra* note 36, at pg. 202.

235. *Id.* at pgs. 199–200.

236. *Id.* at pg. 201.

237. *Southwest Power Pool*, 106 F.E.R.C. ¶ 61,110, at P 188 (2004).

needs."[238] Rather, the RTO should pursue projects that "make generation markets more competitive," by, for example, alleviating congestion that may enhance generator market power.[239] FERC pushed back on IOU privileges, determining that RTOs may not grant transmission owners rights to screen projects prior to the RTO's consideration[240] and selectively rejected RTO proposals to grant IOUs rights-of-first refusal (ROFR) to construct projects identified in the RTO plan.[241] FERC also sought to involve non-IOUs in the planning process by ensuring that stakeholders could participate,[242] ordering transparency "so that all market participants will have confidence that the process is fair and efficient,"[243] and attempting to provide opportunities for non-IOUs to develop projects in the regional plan.[244]

FERC was optimistic that the central-planning development model, whether led by an IOU or RTO, would be replaced by "well-defined transmission rights and efficient price signals" that would facilitate market-driven expansion.[245] Such merchant projects would "not have the economic safety net of assured cost recovery"[246] from captive ratepayers as IOUs had always enjoyed through FERC-approved cost-based rates. Initially, FERC expected that merchant development

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238. *PJM Interconnection*, 96 F.E.R.C. ¶ 61,061, at p. 61,240; *Arizona Pub. Serv. Co.*, 101 F.E.R.C. 61,033, at P 212 (2002); *see also Southwest Power Pool*, 106 F.E.R.C. ¶ 61,110, at P 188 (2004); *Cleco Power*, 101 F.E.R.C. ¶ 61,008, at P 119 (2002).

239. *PJM Interconnection*, 96 F.E.R.C. ¶ 61,061, at p. 61,240 (citing *GridFlorida*, 94 F.E.R.C. ¶ 61,363, 62,367 (2001)); *Midwest ISO*, 97 F.E.R.C. 61,326, 62,520 (2001).

240. *PJM Interconnection*, 96 F.E.R.C. ¶ 61,061, at p. 61,240; *New York ISO, et al.*, 96 F.E.R.C. ¶ 61,059 at p. 61,203 (2001); *Carolina Power & Light Co.*, 94 FERC 61,273, at p. 62,009 (2001); *Southwest Power Pool*, 106 F.E.R.C. ¶ 61,110, at P 188.

241. *PJM Interconnection*, 96 F.E.R.C. ¶ 61,061, at p. 61,241; *Cleco Power*, 101 F.E.R.C. ¶ 61,008, at P 117; *Carolina Power & Light Co.*, 94 F.E.R.C. ¶ 61,273, at p. 62,010, *order on reh'g*, 95 F.E.R.C. ¶ 61,282, at p. 61,996 (2001); *Arizona Pub. Serv. Co*, 101 F.E.R.C. ¶ 61,033, at P 212, *order on reh'g*, 101 F.E.R.C. ¶ 61,350, at PP 65–66 (2002); *Southwest Power Pool*, 111 F.E.R.C. ¶ 61,118, at P 79 (2005), *order on reh'g*, 112 F.E.R.C. 61,319, at P 48 (2005). As discussed in the next section, MISO, PJM, SPP, and ISO-NE all had ROFRs in their tariffs.

242. *Alliance Cos.*, 96 F.E.R.C. ¶ 61,052, 61,144 (2001); *PJM Interconnection*, 96 F.E.R.C. ¶ 61,061, at pp. 61,240–41; *Translink Transmission Co.*, 101 F.E.R.C. 61,140, at P 58 (2002); *ISO-NE*, 106 F.E.R.C. ¶ 61,280, at P 213 (2004).

243. *GridFlorida*, 94 F.E.R.C. ¶ 61,363, at p. 62,367.

244. *PJM Interconnection*, 96 F.E.R.C. ¶ 61,061, at p. 61,241; *Midwest ISO*, 97 F.E.R.C. ¶ 61,326, at p. 62,520 (2001); *Carolina Power & Light Co.*, 94 F.E.R.C. ¶ 61,273, at p. 62,009; *ISO-NE*, 109 F.E.R.C. ¶ 61,147, at P 159 (2004).

245. Order No. 2000, *supra* note 36, at pg. 200. (The Department of Energy was also bullish on market-based transmission expansion. In its 2002 National Transmission Grid Study it proclaimed that "[t]he goal of RTO planning should be to identify transmission needs and the criteria for evaluating proposed solutions, and then to empower the market to respond to these needs, including, if necessary, support for market solutions in state regulatory proceedings.") National Grid Study, *supra* note 198, at 51. (RTOs too were optimistic that market-based approaches would supersede administrative planning. PJM told FERC that under its proposed planning process it would "not propose construction of a transmission upgrade until it has exhausted the possibility that the market will produce a solution to congestion or similar market failures. . . . Only when these two conditions are satisfied - that a transmission upgrade would be the economically best solution, and the market has not produced a solution - will PJM 'intervene.'"); *PJM Interconnection*, 104 F.E.R.C. ¶ 61,124, at P 32 (2003).

246. *TransEnergie U.S.*, 91 F.E.R.C. ¶ 61,230, at p. 61,836 (2000) (quoting the company's filing in Docket No. ER00-1).

would be driven by energy market price differentials, with developers earning revenue either from tradable financial or physical transmission rights or by moving energy from a low-priced region to a high-priced region.[247] In 2000, FERC granted a developer "negotiated rate authority" for the first time, reasoning that because no customer would pay more than the energy price differentials between the line's two terminals, the rate would be effectively capped.[248] In subsequent proceedings, FERC purported to be flexible in its review of developers' applications, stating that it aimed to "assist merchant transmission providers in exploring innovative methods for adding transmission to the power grid and for securing the financing needed for such projects."[249]

In 2009, FERC substantially changed its review criteria in response to growing interest in a different merchant model where the developer earns revenue from selling capacity to subscribing generators.[250] FERC's new policy allowed merchant developers to negotiate with customers for transmission capacity, rather than requiring developers to auction all capacity as it had mandated in prior orders.[251] FERC concluded that allowing developers to negotiate for capacity would improve projects' prospects for obtaining financing and actually being built.[252]

Initially, FERC saw merchant transmission as a mechanism for "expanding competitive generation alternatives for customers"[253] that could complement its reforms designed to unleash competitive generation. But merchant transmission could have also mitigated IOU transmission dominance by providing a pathway for transmission developers outside of the centrally planned, cost-of-service model that had been controlled by IOUs. Merchant projects might have obviated the need for additional IOU-developed infrastructure and provided so-called yardstick competition by revealing to regulators that transmission could be developed at a lower cost than IOUs had been providing it.

In practice, despite FERC's efforts to craft a regulatory path forward for merchant projects, these projects are relatively rare.[254] In general, IOUs build all transmission projects located in their retail service territories, including segments of projects that span across more than one IOU territory. Where an RTO determines that a project will benefit multiple IOUs in the region, each IOU pays a share of

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247. Paul L. Joskow, MIT Center for Energy and Environmental Policy Research, Working Paper, *Competition for Electric Transmission Projects in the U.S.: FERC Order 1000*, at 3–6 (Mar. 2019), http://ceepr.mit.edu/files/papers/2019-004.pdf (describing the merchant models).

248. Heidi Werntz, *Let's Make a Deal: Negotiated Rates for Merchant Transmission*, 28 PACE ENVTL. L. REV. 421, 443–48 (2011) (discussing *TransEnergie U.S.*, 91 F.E.R.C. ¶ 61,230).

249. *Neptune Reg'l Transmission Sys.,* 103 F.E.R.C. ¶ 61,213, at P 18 (2003); Werntz, *supra* note 248, at 453–56 (discussing "transitional" proceedings).

250. *Chinook Power Transmission*, 126 F.E.R.C. ¶ 61,134, at P 2 (2009) (describing proposed line that would transmit renewable energy).

251. Werntz, *supra* note 248, at 453–55 (citing *Chinook Power Transmission*, 126 F.E.R.C. ¶ 61,134).

252. *Id.* at 453–56; *Allocation of Capacity on New Merchant Transmission Projects and Cost-Based, Participant Funded Transmission Projects*, 142 F.E.R.C. ¶ 61,038 (2013).

253. *TransEnergie U.S.*, 91 F.E.R.C. ¶ 61,230, at p. 61,838.

254. Joskow, *supra* note 247, at 4–6 (observing that few projects adopted the LMP-based model); *Id.* at 24–25 (identifying four LMP-based projects that connect to New York).

the project costs commensurate with the benefits it is expected to receive.[255] Projects planned by an RTO are paid for through cost-of-service rates.[256]

IOUs deserve some of the blame for the dearth of merchant projects, particularly with regard to the later "pipeline" model projects. As other industry experts have documented, merchant developers have had difficulties siting their projects.[257] States site nearly all transmission, and many states implement siting laws and regulations that are biased in favor of IOU projects and may even prohibit non-IOU transmission development.[258] IOUs have actively opposed merchants, no doubt seeking to protect their local monopolies.[259] Merchant projects must also navigate the IOU-dominated interconnection process.[260]

C. FERC Mandates Planning Procedures for Cost-of-Service Transmission Development

Following the demise of SMD in 2005, FERC refocused its attention on its Open-Access mandate. In Order No. 890, its first major order after it terminated SMD, FERC reached the now-familiar conclusion that "opportunities for undue discrimination [by IOUs] continue to exist."[261] Among several problems it identified with OATTs, FERC concluded that they contained "only minimal requirements regarding transmission planning."[262] FERC found that, because it could not "rely on the self-interest of transmission providers to expand the grid in a nondiscriminatory manner," it would formalize planning processes to ensure that IOU transmission development supported competitive wholesale power markets.[263]

Building on its statements in RTO compliance orders, FERC required transmission providers to amend their OATTs with transmission planning procedures that would "provide for the timely and meaningful input and participation of all

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255. *See*, *e.g.*, Illinois Commerce Comm'n. v. FERC, 721 F.3d 764 (7th Cir. 2013).

256. *See*, *e.g*,., *Primary Power,* 131 F.E.R.C. ¶ 61,015, at PP 67–72 (2010).

257. *See, e.g.,* Alexandra B. Klass & Jim Rossi, *Revitalizing Dormant Commerce Clause Review for Interstate Coordination*, 130 MINN. L. REV. 129, 187–88 (2015).

258. *Id.*; *See also*, *e.g.*, Alexandra B. Klass, *Takings and Transmission*, 91 N. CAROLINA L. REV. 1079 (2013).

259. *See, e.g.*, Brief of Respondent-Appellee Commonwealth Edison at 43, Illinois Landowners All. NFP v. Illinois Commerce Comm'n, 90 N.E.3d 448 (Ill. 2017) (No. 121302) (urging the court to reverse regulators' finding that a merchant developer was a "public utility" under Illinois law).

260. *See infra* note 420.

261. Order No. 890, *supra* note 201, at PP 26, 39, 422–25 (repeating conclusions from Order No. 888 and finding that existing tariffs do not counteract IOUs' incentives to plan for themselves); *Id.* at P 524 ("[I]t is not in the economic self-interest of transmission providers to expand the grid to permit access to competing sources of supply."); Order No. 2003, 68 Fed. Reg. 49,845 at PP 11–12 (Aug. 19, 2003).

262. Order No. 890, *supra* note 201, at PP 52, 57, 420 ("Order No. 888-A did not, however, require that transmission providers coordinate with either their network or point-to-point customers in transmission planning or otherwise publish the criteria, assumptions, or data underlying their transmission plans. The Commission also did not require joint planning between transmission providers and their customers or between transmission providers in a given region.").

263. *Id*. at PP 52, 57, 422 ("For example, a transmission provider does not have an incentive to relieve local congestion that restricts the output of a competing merchant generator if doing so will make the transmission provider's own generation less competitive."), P 524 ("[I]t is not in the economic self-interest of transmission providers to expand the grid to permit access to competing sources of supply.").

interested customers" and other stakeholders.[264] Comparability and transparency once again guided FERC's reforms. Order No. 890 requires transmission providers to plan for the needs of their customers on a comparable basis as they plan for their own needs.[265] To implement this comparability mandate, transmission providers must collect the same type of information from their customers about their projected needs that providers use to plan for their own needs. Providers must also "consider" data and comments submitted by customers and stakeholders and treat similarly situated customers comparably in the planning process.[266] As it did in Order No. 888, FERC opened the black box of transmission information, requiring disclosure of basic methodology and criteria that providers use to develop transmission plans.[267]

As in Orders No. 888 and 2000, independence and regionalization were optional. Under Order No. 890, IOUs control the planning process and retain the final say on the content of their transmission plans.[268] FERC required transmission providers to "coordinate" planning with neighboring providers but only insofar as necessary to ensure simultaneous feasibility of each provider's individual plan and to "identify" projects that could relieve congestion or integrate new resources.[269] FERC did not require providers to collaborate on a unified regional plan or to pursue projects that would be more cost-effective than projects listed in each IOU's individual plan. Given their regional scope, however, RTOs were already developing regional plans, and complied with Order No. 890 by demonstrating that their planning processes met FERC's requirements.[270]

264. Order No. 890, *supra* note 201, at P 454; *see also Southern Cal. Edison Co.,* 168 F.E.R.C. ¶ 61,170, at P 40 (2019) (explaining that "the undue discrimination at issue [in Order No. 890] is not the potential limitation on stakeholder advocacy per se, but rather the undue discrimination in transmission access that could occur without stakeholder advocacy").

265. *Id.* at PP 454, 494–95.

266. *Id*. at P 454 (stating that the planning process must "ensure that customers are treated comparably"); *id.* at P 486 (stating that "equivalent information must be provided by transmission customers to ensure effective planning and comparability); *id.* at 494; *PJM Interconnection,* 123 F.E.R.C. ¶ 61,163, at P 52 (explaining comparability principle as applied to planning).

267. *Id.* at PP 471–73.

268. Order No. 890-A, *Preventing Undue Discrimination and Preference in Transmission Service*, 121 F.E.R.C. ¶ 61,297 at PP 188–89 (2007).

269. Order No. 890, *supra* note 201, at PP 523–24.

270. *California Sys. Operator*, 143 F.E.R.C. ¶ 61,057, at PP 32, 35, 42, 54 (2013) (finding that the ISO's regional planning process already adopted Order No. 890's principles and complied with Order No. 1000's directive to identify regional solutions); *PJM Interconnection*, 142 F.E.R.C. ¶ 61,214, at PP 38, 52, 59, 65 (2013) (finding that PJM's regional planning process already adopted Order No. 890's principles and complied with Order No. 1000's directive to identify regional solutions); *Southwest Power Pool*, 144 F.E.R.C. ¶ 61,059, at PP 36, 39, 46, 52, 56 (2013) (finding that the SPP's regional planning process already adopted Order No. 890's principles and complied with Order No. 1000's directive to identify regional solutions); *ISO New England*, 143 F.E.R.C. ¶ 61,150, at PP 32, 45, 64 (2013) (finding that the ISO's regional planning process already adopted Order No. 890's nine principles and partially accepting revisions so it complies with Order No. 1000); *Midwest Indep. Transmission System Operator*, 142 F.E.R.C. ¶ 61,215, at PP 42, 47, 71, 80 (2013) (finding that the ISO's regional planning process already adopted Order No. 890's principles and accepting revisions so it identifies regional solutions in compliance with Order No. 1000); *New York Indep. Sys. Operator*, 143 F.E.R.C. ¶ 61,059, at PP 31, 42, 50, 56, 75 (2013) (finding that the ISO's regional planning process already adopted Order No. 890's principles and partially accepting revisions so it complies with Order No. 1000).

Despite incorporating the FERC-mandated planning principles, RTOs were seen by some industry participants as little more than a forum for evaluating IOU proposals in a process dominated by IOUs.[271] The ISO-NE planning process in effect until 2012 exemplifies a power pool-era paradigm of IOU-centered planning. Testimony filed at FERC by two IOU executives explains that ISO-NE's planning relied on a "level of intercompany planning coordination" that "dates back several decades."[272] The IOU executives described an iterative process between IOUs and ISO-NE that relied on IOUs working collaboratively with each other to do most of the analytical work that supports ISO-NE's planning decisions.[273] The IOU executives argued that their companies have the resources and expertise to perform the relevant studies, while the ISO "has much more limited resources and lacks the local knowledge of the [utilities] with respect to particular portions of the system."[274] Only after IOUs "share[d] their work with each other" in a process of "open collaboration, both among the [utilities] and between the [utilities] and the ISO's planning staff," did they then provide their results to non-IOU stakeholders.[275] The IOU executives warned that competition in transmission development would reduce collaboration and information flow, as utilities would be reluctant to share their intellectual property with competitors.[276]

In 2011, FERC determined that these sort of processes afford IOUs with "opportunities to engage in undue discrimination."[277] In Order No. 1000 — the most recent industry-wide rule on transmission planning — FERC employed several mechanisms to pry control over regional transmission development from IOUs and break the IOU-by-IOU planning model. First, the crux of the order is a mandate that IOUs collaborate within their region to evaluate transmission solutions that can meet the region's needs more efficiently than each provider's individual local plans.[278] FERC determined that merely confirming simultaneous technical

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271. Comment of Pattern Transmission, FERC Docket AD09-08 (Nov. 23, 2009), at 7 (stating that in RTO planning processes there is "an almost unconscious assumption that transmission planning begins with incumbent transmission owners"); Comment of Green Energy Express, FERC Docket AD09-8 (Nov. 23, 2009), at 3 (stating that market participants in California have "concluded that transmission projects sponsored by independent transmission developers are not being fairly and fully considered by the CAISO, and only those projects sponsored by incumbent Participating Transmission Owners are being considered"); Comment of NRG, FERC Docket AD09-8 (Nov. 23, 2009), at 12 (stating that the NYISO transmission planning process "contains unwarranted preferences for utility-built transmission," and that the "default solution" is the transmission project proposed by transmission owners); Comments of ITC Holdings Corp, FERC Docket AD09-8 (Nov. 23, 2009), at 6 (claiming that in MISO "transmission planning is still 'bottom up,'" meaning that "individual transmission owner plans are submitted for review . . . and are checked for conflicts, but no effort is made to look at the needs from a larger perspective, for example to determine the most efficient infrastructure to serve the region's long-term needs").

272. Prepared Direct Testimony of David Boguslawski and Carol Sedewitz, Addendum to ISO-NE Compliance Filing, Docket No. ER13-193, (Oct. 25, 2012), at 4–5. Mr. Boguslawski was Vice President of Transmission Strategy and Operations for Northeast Utilities. Ms. Sedewitz was Director, Electric Transmission Planning for National Grid.

273. *Id.* at 8, 11.

274. *Id.* at 11.

275. *Id.* at 12.

276. *Id.* at 24–25.

277. Order No. 1000, *supra* note 189, at PP 59, 78, 147.

278. *Id.* at PP 80, 147.

feasibility of each IOU's local expansion plan was insufficient to satisfy its regional planning mandate.[279] Instead, it required IOUs to engage in a separate planning process managed by a regional planning entity. The regional planning mandate forces each IOU to participate in a regulated planning process that is not focused on its own state-granted territory.

Second, FERC required that regional planning procedures specify criteria for evaluating proposed projects that are neutral as to the project developer or sponsor. Proposal submission requirements and project selection processes must treat IOUs and non-IOUs comparably.[280] Third, FERC required that both local and regional planning processes allow stakeholders to identify the transmission needs driven by public policies.[281] This requirement aimed to remedy opportunities for undue discrimination by preventing providers from planning only for their own needs.

Fourth, FERC applied the Order No. 890 principles to regional planning.[282] FERC concluded that its planning principles ensure that non-IOUs have access to relevant information and opportunities to input information into the planning process, both of which allow them to meaningfully contribute to transmission plan development.[283] Information transparency, FERC determined, is critical to assessing potential impacts proposed projects have on the regional network and enabling the planning process to select the most cost-effective projects.[284]

Fifth, FERC required transmission providers to remove rights-of-first-refusal (ROFR) from OATTs for projects included in a regional plan.[285] ROFRs had provided IOUs with exclusive opportunities to develop projects within their state-granted territories, including segments of projects that spanned multiple IOU service territories. With that protection in place, non-IOU developers were unlikely to propose projects during the planning process due to substantial risk that an IOU would exercise its ROFR and develop the proposed project and capture the associated profits protected by cost-of-service FERC-approved rates.[286] FERC therefore determined that ROFRs create opportunities for undue discrimination against non-IOU developers and found that ordering their removal is consistent with its duty to counteract IOU transmission dominance.[287] FERC allowed IOUs to retain ROFRs for transmission projects located within their state-granted territories and paid entirely by the IOUs' customers.[288] Only projects whose costs are allocated among regional transmission owners (pursuant to cost allocation rules outlined in Order No. 1000) must be open to non-IOUs.

With these reforms, FERC unlocked cost-of-service transmission development to non-IOUs. While Order No. 890 attempted to open planning processes, it

279. *Id*.
280. *Id.* at PP 316–17, 323–29, 335–36.
281. *Id.* at P 205.
282. Order No. 1000, *supra* note 189, at P 18.
283. *Id.* at PP 149–50.
284. *Id.* at P 152.
285. *Id.* at P 253.
286. *Id.* at PP 256–57, 284–86, 320.
287. Order No. 1000, *supra* note 189, at P 286; *see also* Order No. 1000-A, *supra* note 211, at PP 361–63.
288. Order No. 1000, *supra* note 189, at PP 262, 318, 335; Order No. 1000-A, *supra* note 211, at P 425.

left IOUs in control and with the exclusive opportunity to build projects financed by government-authorized cost-of-service rates. Non-IOU developers could earn only market-based revenues,[289] and were shut out of development opportunities identified by IOUs or RTOs in regulated planning processes. FERC's order promised to restructure the transmission segment of the industry by — for the first time — requiring IOUs to compete for the opportunity to earn cost-of-service rates associated with new transmission projects.

Without ROFRs that effectively assigned project development to IOUs, regional planners needed to establish mechanisms to select developers. FERC provided little guidance, requiring only that the regional process "make it possible for nonincumbent transmission developers to compete in the proposal of more efficient or cost-effective transmission solutions."[290] RTOs and other regional planning organizations have adopted two approaches.[291] Under the sponsorship model, IOUs and non-IOU developers propose (or "sponsor") projects that aim to address a regional need identified by the regional planning entity. Sponsors may offer very different solutions to the transmission needs identified by the regional planner, including projects that utilize non-traditional technologies, such as batteries.[292] The regional planning entity then chooses projects that it finds cost-effectively address regional needs and tasks the project sponsor with developing the project. Under the solicitation model, the regional planning entity identifies specific projects rather than merely opening that task up to market participants, and then runs competitive processes to select a developer for each project.

Both models harness competitive forces but to different ends. The sponsorship model is a bottom-up approach that uses an open process to induce developers to offer innovative project proposals.[293] The solicitation model is a top-down process that seeks to reduce costs of projects initially developed by a central planner. Under the latter model, the regional planning entity determines the set of projects

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289. *But see Primary Power*, 131 F.E.R.C. ¶ 61,015 (2010), *order on reh'g,* 140 F.E.R.C. ¶ 61,052 (2012). Shortly before it issued Order No. 1000, FERC determined that a non-IOU developer was eligible under the PJM governing documents to be selected in the regional planning process to develop an economic expansion project and receive cost-of-service rates under the tariff. PJM IOUs unsuccessfully argued that they had exclusive rights to develop all regional projects.

290. Order No. 1000-A, *supra* note 211, at P 87.

291. Review of Recent Regional Plans, *supra* note 197, at 16–17; *see also* Order No. 1000, *supra* note 189, at PP 320–21 (mentioning "bottom up" and "top down" transmission planning).

292. Review of Recent Regional Plans, *supra* note 197, at 16–17, 23–31; *see also*, *e.g.*, ISO NEW ENGLAND, INC., BOSTON 2028 REQUEST FOR PROPOSAL (RFP) – REVIEW OF PHASE ONE PROPOSALS (2020), https://www.iso-ne.com/static-assets/documents/2020/07/final_boston_2028_rfp_review_of_phase_one_proposals.pdf (summarizing 36 project proposals from eight developers in response to ISO-NE's first open solicitation, with estimated costs ranging from $49 million to $745 million).

293. *Id*. at 10; *see also*, *e.g.*, PJM, 2020 REGIONAL TRANSMISSION EXPANSION PLAN (RTEP), at 45 (2020), https://www.pjm.com/-/media/library/reports-notices/2020-rtep/2020-rtep-book-1.ashx [hereinafter RTEP]:

> PJM seeks transmission proposals during each RTEP window to address one or more identified needs – reliability, market efficiency, operational performance and public policy. RTEP windows provide an opportunity for both incumbent and non-incumbent transmission developers to submit project proposals to PJM for consideration. When a window closes, PJM proceeds with analytical, company, constructability and financial evaluations to assess proposals for possible recommendation to the PJM Board.

that will meet the region's needs. Following that, the planning entity aims to lower costs of each project by selecting developers through competitive processes.

Under both models, the competitive regional process merely fills in the gaps of non-competitive IOU-specific local planning processes.[294] IOUs have no obligation to assure that the totality of their local plans is cost-effective from a regional perspective. The regional process required by Order No. 1000 does not supersede each IOU's local planning. In non-RTO regions, the aggregation of local plans forms the basis against which potential regional projects are judged.[295] RTOs take different approaches, but in general IOUs' local plans "serve as a starting point" for RTO regional planning.[296] This IOU-first approach prioritizes IOUs' interests in building infrastructure within their state-granted service territories.

This bifurcated structure of transmission planning follows from Order No. 1000. The evaluation and selection process principles outlined in Order No. 1000 apply only to projects that the planner determines have regional benefits and are therefore paid for through regional cost allocation.[297] Order No. 1000 does not apply to facilities located within an IOU's state-granted service territory that are paid for by that utility's ratepayers.[298] Local development remains at the IOU's discretion, constrained only by the procedural requirements of Order No. 890. Regional planning is thus the exception, not the rule. Transmission development continues to be driven by IOUs in IOU-specific planning processes.[299]

Order No. 1000 says little about merchant transmission projects.[300] To be clear, merchant projects are distinct from non-IOU projects planned through an

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294. *Id*. at 23–28 (summarizing relationship between the regional planning process conducted by each regional planning entity and member utilities' local transmission planning); *see also,* RTEP, *supra* note 293, at 57 (noting that supplemental projects developed by member utilities "are not required for compliance with system reliability, operational performance or market efficiency economic criteria, as determined by PJM" but "are included in PJM's RTEP models").

295. *See, e.g.*, *Pub. Serv. Co. of Colo.*, 48 F.E.R.C. ¶ 61,213, at P 124 (2014):

> [O]nce the local transmission plans are rolled up and are reviewed to identify regional needs, Order No. 1000 requires public utility transmission providers in the transmission planning region to undertake [] the additional step of conducting an analysis to determine whether there are more efficient or cost-effective transmission solutions to meet the regional transmission needs of the region.

See also, Joseph H. Eto & Giulia Gallo, *Regional Transmission Planning: A Review of Practices Following FERC Order Nos. 890 and 1000*, BERKLEY LAB ELEC. MKT. & POLICY vii (Nov. 2017), https://eta-publications.lbl.gov/sites/default/files/lbnl_2001079_final_102519.pdf ("In most non-ISO/RTO regions, the participating utilities' individual transmission plans are combined to form a baseline regional transmission plan. The baseline regional transmission plan is then used to evaluate proposals from stakeholders and prospective transmission developers for both regional transmission needs and regional transmission solutions."); *Id.* at 8:

> the regional transmission planning process . . . primarily [] provide[s] an open, transparent means by which stakeholders are allowed to participate in regional transmission planning . . . can have their proposed solutions vetted against those of the incumbents whose projects are already contained in the baseline regional transmission plan.

296. Review of Recent Regional Plans, *supra* note 197, at 23–28; Eto & Gallo, *supra* note 295, at 13–16; Comments of NYISO, Docket No. RM10-23, (Sep. 28, 2010), at 6 (noting that NYISO planning starts with transmission owners' local plans).

297. Order No. 1000, *supra* note 189, at P 165.

298. *Id*. at PP 262, 318-19.

299. Review of Recent Regional Plans, *supra* note 197, at 23–28; Eto & Gallo, *supra* note 295, at 13-16.

300. Order No. 1000, *supra* note 189, at PP 163–65.

Order No. 1000-compliant process. Merchant projects are "unplanned" from FERC's perspective and can only earn market-based revenue. Order No. 1000 projects, whether developed by an IOU or another entity, are planned through a FERC-approved process and receive cost-of-service rates pursuant to cost allocation rules that meet the Order No. 1000 standards.

Despite the limited reach of Order No. 1000, IOUs and RTOs have attempted, and often succeeded, at scaling back competitive development even further. In the next section, I discuss these efforts to reduce the impacts of Order No. 1000 on IOU transmission dominance.

D. The FERC-Regulated Planning Process is a Protection Racket

IOUs responded to Order No. 1000 by filing suit in federal court (along with numerous TDUs[301]), arguing that the FPA does not provide FERC with authority to require public utilities to jointly plan regional transmission.[302] As their unsuccessful litigation was playing out, IOUs, often supported by RTOs, made two key moves to limit transmission competition. First, they argued in Order No. 1000 compliance proceedings that FERC has no authority to remove ROFRs from RTO tariffs. Second, they proposed numerous project categories where ROFRs would remain in effect even if they lost the first argument.[303] On the first issue, IOUs lost in every proceeding at FERC and four times in federal appeals courts. On the second issue, FERC has allowed several exemptions, undercutting its ambitions to open planned transmission development to competition.

I will not recount the range of arguments IOUs offered in FERC proceedings and federal court appeals in opposition to FERC's ROFR rollback, but I think it is worth dwelling on IOUs' claims about the source of authority for their ROFRs. Their claims explain in part why IOUs formed ISOs and RTOs and elucidate the relationship between RTOs and their IOU members. Recall that following Order No. 888, IOUs in tight power pools resisted FERC's directive that they relinquish decisionmaking authority to new independent entities.[304] Perhaps recognizing that the days of absolute IOU control were waning under a more assertive FERC, the

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301. While IOUs were likely seeking to protect their transmission dominance, municipal utilities that opposed Order No. 1000 were more likely to be concerned about increasing transmission costs due to new regional cost allocation methodologies. TDUs have been skeptical of FERC's regionalization efforts and have protested the administrative costs of RTOs and development of RTO capacity markets.

302. *See* D.C. Circuit Docket No. 12-1232. The following IOUs or utility holding companies signed a brief arguing FERC does not have authority to mandate regional transmission planning: FirstEnergy, Oklahoma Gas & Electric, PSE&G, Southern Company, and all MISO transmission owners, which then included Ameren, Duke Energy, Montana-Dakota Utilities Co., NiSource, Otter Tail Power Co., Vectren, and Xcel. These additional utilities hid behind a front group called "Coalition for Fair Transmission Policy" that also signed the brief: CMS, ConEd, DTE, Progress Energy, and SCANA. Several public power entities, a cooperative entity, MISO, and three PUCs signed the brief as well.

303. *Id.* at P 329 (committing to evaluate exemptions from competition when relevant "to ensur[ing] the incumbent transmission provider can meet its reliability needs or service obligations").

304. *Supra* notes 127–133 and accompanying text (describing rejected ISO proposals that were inconsistent with FERC's independence principle); *see also* Allegheny Power, Order No. 2000 RTO Compliance Filing and Petition for Declaratory Order, FERC Docket No. RT01-10, Oct. 16, 2000 ("Allegheny . . . disfavors allowing its significant dollar investment in transmission facilities to be controlled and operated by a nonprofit ISO." Allegheny explained that it was "affected by the problem of pancake elimination.")

former power pool member IOUs coalesced around a governance approach that allowed them to retain influence through RTO committees.[305] These early-mover IOUs likely had various motivations for ceding control. For some IOUs, joining an RTO was a condition imposed by FERC for approving a merger application.[306] Others were bullish about the new organized wholesale markets and believed that joining an RTO would enable them to profit from new opportunities to sell power.[307] Filings in Order No. 1000 proceedings reveal another factor.

IOUs in all four multi-state RTOs as well as three of the RTOs themselves[308] told FERC that ROFRs were part of the "quid pro quo for making [] RTO formation a reality."[309] PJM IOUs further explained that their "exclusive right[s] to build planned cost-of-service transmission in their zones . . . pre-existed PJM," and agreements between PJM and its member IOUs preserved those rights.[310] RTOs, according to this version of events, were designed to retain the protections formerly provided by IOU power pool agreements. When FERC's Open-Access mandate diminished IOUs' generation dominance, IOUs sought assurances that RTOs would protect their local transmission monopolies.

PSE&G, a PJM-member IOU, put a finer point on it, arguing that "the core business of the [ ] transmission owners is to build, own and maintain transmission facilities, [and] an RTO arrangement that would divest that owner of a substantial portion of its core business is simply incompatible with its business model."[311] Put differently, PSE&G argued that non-competitive transmission development is its

305. *Supra* notes 139–141 and accompanying text (describing two-tier governance structures).

306. *See, e.g., Am. Elec. Power Co. et al.*, 90 F.E.R.C. ¶ 61,242, at p. 61,787.

307. *See, e.g.*, PSE&G, PSEG SUMMARY: ANNUAL REPORT 1998 7 (1998), https://www.nrc.gov/docs/ML1810/ML18107A187.pdf (telling investors that industry restructuring was "creating a burgeoning wholesale trading market" and that its generation fleet was "well-situated to take advantage of opportunities" in PJM and NYISO); Am. Elec. Power, AEP Annual Summary Report: 2000 4 (2000), https://www.annualreports.com/HostedData/AnnualReportArchive/a/NYSE_AEP_2000.pdf (proclaiming that its "portfolio of businesses and assets positions [it] uniquely for success in the high-growth wholesale segment").

308. PJM did not opine on whether it was legal or appropriate for FERC to order removal of ROFRs. ISO-NE, MISO, and SPP all sided with their IOU members.

309. *PJM Interconnection,* 147 F.E.R.C. ¶ 61,128, at P 102, n.187 (2014); *ISO New England*, 150 F.E.R.C. ¶ 61,209, at P 171 (2015) (arguing that ROFRs were part of a "trade-off" wherein utilities gave up operational control of their facilities and joined an RTO); Request for Rehearing of Oklahoma Gas & Electric, Docket No. ER13-366, Aug. 19, 2013, at 13 (stating that ROFRs were part of a "natural quid pro quo for agreeing to become subject to a regional planning and expansion process"); Order No. 1000-A, *supra* note 211, at P 355 (noting MISO's argument that its ROFR is a "fundamental element of [its] structure as an RTO"); Request for Rehearing of the MISO Transmission Owners, Docket No. ER13-187, Apr. 22, 2013, at 26 (arguing that the ROFR was part of a bargained-for exchange pursuant to which IOUs ceded control of their transmission to MISO).

310. *Primary Power*, 140 F.E.R.C. ¶ 61,052, at P 58 (2012) (quoting filing by PJM IOUs). The IOUs provide no authority for this supposed right to build all transmission. Request for Rehearing of PJM Transmission Owners Group, FERC Docket No. ER10-253, May 13, 2010. *See also* Request for Rehearing of PSEG Companies, FERC Docket No. EL10-52, May 13, 2010 (claiming that PJM Transmission Owners have the "contractual and FERC-approved exclusive right . . . to build non-merchant transmission upgrades with their service territories"); Brief of the PSEG Companies, The PPL PJM Companies, and Exelon Corporation, *Public Serv. Elec. and Gas Co. v. FERC,* Docket No. 12-1382 (D.C. Cir. Apr. 10, 2013) (repeating same argument).

311. Request for Rehearing and Clarification of PSE&G, Docket No. ER10-253 (May 13, 2010); *see also* Testimony of Maureen Borkowski, Vice President Ameren Services on Behalf of MISO Transmission Owners, Docket No. AD09-8 (Sept. 21, 2009), at 3 ("By joining the Midwest ISO, the Transmission Owners did not agree to forego their rights to invest in and earn a return on new assets in their own systems.").

"core business" and any intrusions by competitor developers is equivalent to deprivation of its property and inconsistent with the RTO's protective purpose.[312] The company did not point to any state law to support its argument but instead claimed that it has a constitutionally protected right under the Fifth Amendment to a monopoly in the development of interstate transmission lines within its state-granted service territory.[313] Other PJM IOUs made similar constitutional claims.[314] Neither FERC nor any federal court endorsed these novel theories.

Order No. 1000 voided this supposed bargain between RTOs and their IOU members as a matter of law. IOUs had argued that FERC could not order RTOs to remove ROFRs because the relevant tariff provisions were protected by the so-called *Mobile-Sierra* presumption, which limits FERC's authority to abrogate contract terms.[315] FERC responded that the *Mobile-Sierra* presumption that freely negotiated contracts between sophisticated parties are just and reasonable is rooted in an assumption that contract negotiations are between adversarial parties pursuing independent interests. FERC concluded that IOUs forming RTOs shared the common aim of "protecting themselves from competition in transmission development."[316] Under those circumstances, where the parties to the RTO agreement were not adversarial with respect to ROFR provisions, FERC cannot presume that the outcome is just and reasonable.[317] Four federal appeals court affirmed FERC's orders removing multi-state RTO ROFRs, with two specifically endorsing FERC's conclusion that *Mobile-Sierra* deference does not apply to agreements among parties with common interests that seek to exclude competition.[318]

312. PSE&G similarly argued that "allowing PJM to designate other entities to build non-merchant transmission facilities in the zone of an existing transmission owner constitutes an unconstitutional regulatory taking of the PJM TO's contractual rights under the various PJM agreements without just compensation in violation of the U.S. Constitution." Request for Rehearing and Clarification of PSE&G, Docket No. ER10-253 (May 13, 2010), at 19. When TOs had an opportunity to litigate this claim in federal court in proceedings about Order No. 1000, they declined to raise this argument.

313. *Id.*

314. Request for Rehearing of PJM Transmission Owners Group, FERC Docket No. ER10-253 (May 13, 2010), at 37 ("any abrogation or impairment of the transmission owners' contractual rights to build under the [PJM agreement] is in contravention of the Due Process and Takings Clauses of the U.S. Constitution").

315. *See, e.g., Midwest Indep. Sys. Operator, et al.*, 142 ¶ F.E.R.C. 61,215, at P 175 (2013).

316. *PJM Interconnection, et al.,* 142 F.E.R.C. ¶ 61,214, at P 189 (2013); *Midwest Indep. Sys. Operator, et al.*, 142 ¶ F.E.R.C. 61,215, at P 183 (2013); *ISO-New England*, 143 F.E.R.C. ¶ 61,150, at P 169 (2013); *Southwest Power Pool, et al.*, 144 F.E.R.C. ¶ 61,059, at P 133 (2013).

317. *See, e.g., PJM Interconnection,* 147 F.E.R.C. ¶ 61,128, at P 106–111 (2014).

318. Oklahoma Gas and Electric Co. v. FERC, 827 F.3d 75, 80 (D.C. Cir. 2016) ("Just as unfair dealing, fraud, or duress will remove a provision from the ambit of *Mobile–Sierra*, so also will terms arrived at by horizontal competitors with a common interest to exclude any future competition."); MISO Transmission Owners, et al. v. FERC, 819 F.3d 329, 335 (7th Cir. 2016) (finding that because the parties to the MISO agreement were "seeking to protect themselves from competition from third parties," the Mobile-Sierra presumption does not apply); *see also* American Transmission Systems Inc., v. FERC, 2016 WL 3615443 (D.C. Cir. 2016, unpublished) (dismissed for lack of jurisdiction); Emera Maine v. FERC, 854 F.3d 662 (D.C. Cir. 2017).

While IOUs and RTOs lost the legal argument, they have largely upheld the spirit of their arrangements. Over the past several years, the vast majority of transmission projects have been developed outside of competitive processes.[319] RTOs that preach competition in power generation have been less sanguine about the value of competition in transmission development. They have supported the shift away from regional projects, which must be developed competitively, to smaller or supposedly time-sensitive projects that IOUs build with little oversight and without competitive pressures.

A "common interest" agreement between PJM and its transmission-owning members illustrates RTO support of the IOUs' anti-competitive agenda.[320] The agreement facilitates closed-door meetings between PJM and IOUs and envisions PJM conferring with IOUs on section 205 filings and providing technical assistance.[321] The crux of the agreement allows the parties to confidentially share information, without limitations and no transparency for non-parties. PJM and its IOUs entered into the agreement a few months after FERC issued Order No. 1000. While I am not aware of whether other RTOs have similar agreements with their IOU members, it is common for RTOs to collaborate with transmission owners on writing transmission rules that disadvantage IOUs' competitors. This sort of exclusive collaboration, particularly where it is facilitated by confidential arrangements, is difficult to square with FERC's broad commitment to comparability and transparency in its major reform orders.

This specific PJM-IOU agreement, and more generally the common practice of RTO-IOU joint FERC filings and legal advocacy, suggest that FERC's "independence" principle fails to remedy IOU transmission dominance. Because FERC has not mandated RTO membership, IOUs may attempt to withdraw their assets from RTO control at any point. The process for doing so would be complex, time-

319. Johannes P. Pfeifenberger, et. al, *Cost Savings Offered by Competition in Electric Transmission*, BRATTLE GRP., at 5 (Apr. 2019), https://brattlefiles.blob.core.windows.net/files/16726_cost_savings_offered_by_competition_in_electric_transmission.pdf (The report commissioned by LS Power, a non-IOU transmission developer, found that from 2013 to 2017 only 3% of transmission investment ($540 million out of $20 billion per year) was committed through processes open to non-IOU developers.) [hereinafter Brattle Report]; *See also* Competitive Transmission Development Technical Conference, Docket No. AD16-18-000, Comments of Transmission Access Policy Study Group at 36 (Oct. 3, 2016); *infra* notes 360–362.

320. On February 24, 2021, PJM's Transmission Owners Agreement Administrative Committee posted two versions of the "Confidentiality and Common Interest Agreement," one dated September 13, 2011, and the other dated January 24, 2017. In a dispute about transmission cost allocation, various parties have made representations to FERC about the agreement in FERC Docket No. EL21-39. LSP Transmission Holdings II, Comment in Support (Feb. 9, 2021); PJM Interconnection, Motion for Leave to File Answer and Answer (Feb. 25, 2021); Indicated Transmission Owners, Answer (Mar. 4, 2021); Silver Run Electric, Response to Request for Abeyance (Mar 5. 2021); Indicated Transmission Owners, Motion for Leave to File Answer and Answer (Mar. 22, 2021).

321. *See, e.g.*, 2011 Agreement at pg. 1: "it is in the common interest of the PJM TOs with the assistance of PJM to develop mutually agreeable filings to be submitted to the FERC . . ."; *id.* at pg. 2: "in order effectively to pursue the Participants' common interests with respect to the Section 205 Filings, the Parties have also each concluded that, from time to time, such interests will be best served by sharing Confidential Information . . ."; 2017 Agreement at pg. 1: "the Section 205 Working Group may request the assistance of PJM in the Section 205 Working Group Matters . . ."

consuming, and costly, and withdrawal would be subject to FERC approval,[322] but IOUs clearly retain the right under the FPA to initiate that process. This option gives each IOU individually, and an RTO's IOU members collectively, leverage over the RTO's management.[323] If an IOU concludes that its RTO is "divest[ing it] of a substantial portion of its core business" by, for example, opening transmission development to competition, that IOU may attempt to withdraw. Losing control of that IOU's transmission assets might complicate the RTO's operations, could lead to a cascade of IOU exits, and would diminish the scope of the RTO's authority. In addition, as the description of the ISO-NE planning process illustrates, RTOs have depended on IOUs for information and analysis. FERC's independence principle does not address this sort of undue influence that may coerce RTOs into advancing the financial and strategic interests of their transmission-owning members.

With their ROFRs in jeopardy beginning in 2010 with FERC's release of the Order No. 1000 proposal, and ultimately eliminated by 2017 following litigation, IOUs and RTOs shielded projects from competitive processes by changing RTO tariffs or interpreting them in a manner that favored IOU interests. FERC has generally supported IOU efforts to evade competitive processes, although, as I describe, FERC did open investigations into various exemptions from competition and rejected some IOU efforts to create additional non-competitive project categories. Below I highlight examples of how RTO rules stifle FERC's efforts to promote competition.

I start in PJM, where IOUs have tripled spending on local non-competitive projects since Order No. 1000 went into effect while the value of PJM-approved regional projects has dropped by a third.[324] To untangle the web of project categories in PJM and illustrate how PJM's tariff reinforces IOU transmission dominance, I begin with PJM's response to Order No. 890. Because PJM's IOU members transferred operational control of their transmission assets to PJM, they did not maintain their own OATTs and therefore relied on provisions in PJM's tariff to demonstrate that their local planning processes complied with Order No. 890.[325]

322. *See* Ari Peskoe, *ISO-NExit: Exploring Pathways for a Utility's Withdrawal from New England's Regional Transmission Organization* (Mar. 2020), http://eelp.law.harvard.edu/wp-content/uploads/ISONexit-Memo.pdf.

323. *See PJM Interconnection, et al.,* 92 F.E.R.C. ¶ 61,282, at p. 61,958 (2000) ("PJM argues that the right to withdraw without notice could undermine ISO independence since there would be a constant overhanging threat that a TO may withdraw if it disagrees with ISO action.").

324. PJM Transmission Expansion Advisory Committee, *Project Statistics* (May 12, 2020), https://www.pjm.com/-/media/committees-groups/committees/teac/2020/20200512/20200512-item-10-2019-project-statistics.ashx. PJM's data shows that annual spending on Supplemental Projects increased from $1.25 billion per year from 2005 to 2013 to $3.73 billion per year from 2014 to 2019. PJM-approved regional projects dwindled from $2.76 billion to $1.86 billion per year. Spending on Supplemental Projects constituted 30% of all transmission spending until 2013, but increased to 65% of all transmission spending from 2014 to 2019. Note that PJM's document labels local IOU spending as Supplemental Projects dating back until 2005 even though that label was not adopted until 2008. FERC conditionally accepted PJM's Order No. 1000 compliance filing on March 22, 2013. *PJM Interconnection, et al.*, 142 F.E.R.C. ¶ 61,214 (2013).

325. *PJM Interconnection,* 123 F.E.R.C. ¶ 61,163, at P 122 (2008); *Monongahela Power Co., et al.*, 156 F.E.R.C. ¶ 61,134, at P 12 (2016) (PJM Transmission owners "opt[ed] to comply with Order No. 890 by participating in the transmission planning process that is outlined the PJM Operating Agreement").

In its compliance filing, PJM distinguished between 1) regional projects that would be subject to approval by PJM's Board and regional cost allocation and 2) local projects that are not needed to meet any PJM reliability, performance, or economic efficiency standard, would not be evaluated by PJM's Board, and whose costs would be borne solely by the local IOU (and collected from its captive ratepayers).[326] For the former category, PJM's then-existing regional planning process (RTEP) formed the basis for its Order No. 890 compliance.[327]

For the latter project category, FERC created new committees (Subregional RTEPs) that would provide forums for stakeholders to review and comment on "Transmission-Owner initiated"[328] "local reinforcement"[329] projects included in local transmission plans.[330] PJM pledged to FERC that it would "evaluate" IOU local planning standards and criteria to "determine if these local reinforcements (called Supplemental Projects) are needed to optimally meet the local transmission owner planning criteria."[331] Through this process, PJM assured FERC that local planning processes of its member IOUs would comply with Order No. 890.[332]

Despite these assurances from PJM, FERC opened an investigation in 2015 into the relationship between Local Plans and the RTEP.[333] After a technical conference, FERC expressed "concern" that "the transmission planning process for Supplemental Projects . . . does not comply with Order No. 890" and ordered PJM IOUs to propose revisions to the PJM tariff or show why they should not be required to do so.[334] Following a comment period, FERC found that PJM IOUs' local planning processes failed to provide stakeholders with meaningful opportunities to participate and therefore violated Order No. 890.[335]

IOUs defended their secretive planning processes by claiming that stakeholder input and information transparency are pointless when the "most obvious

326. *PJM Interconnection,* 123 F.E.R.C. ¶ 61,163, at P 113 (2008).

327. *Id.* at PP 74–76, 140–142.

328. PJM Compliance Filing, Docket No. OA-08-32, at 35 (Dec. 7, 2007).

329. *Id.* at 7.

330. *PJM Interconnection*, 130 F.E.R.C. ¶ 61,167, at P 12 (2010).

331. PJM Compliance Filing, Docket No. OA-08-32, at 35–36 (Dec. 7, 2007); *PJM Interconnection,* 123 F.E.R.C. ¶ 61,163, at P 141 (2008) ("local plans are submitted to PJM for review, concurrence, coordination, and integration in the RTEP"); *PJM Interconnection*, 142 F.E.R.C. ¶ 61,214, at P 59 (2013) ("PJM adds that locally proposed Supplemental Projects are factored into the RTEP process, and if they are found to most efficiently resolve transmission needs, these local projects are included in the regional plan as RTEP projects for the purposes of cost allocation."); *Id.* at P 121; *PJM Interconnection, et al.*, 151 F.E.R.C. ¶ 61,172, at P 22 (2015); *Monongahela Power Co., et al.*, 156 F.E.R.C. ¶ 61,134, at PP 5, 60 (2016).

332. It is noteworthy that PJM detailed this process to FERC only in response to FERC twice ordering PJM to clarify the connection between Local Plans and the RTEP and to specify that local planning will be consistent with Order No. 890 principles. PJM's initial filings were vague on these details. *PJM Interconnection*, 123 F.E.R.C. ¶ 61,163 PP 140–141 (2008); *PJM Interconnection*, 127 F.E.R.C. 61,166 at PP 28–29 (2009).

333. *PJM Interconnection*, 152 F.E.R.C. ¶ 61,197 at P 5 (2015) (noting FERC staff sent a deficiency letter to PJM asking for information about Supplemental Projects and Local Plans); *Id.* at P 15 (establishing technical conference); Notice of Technical Conference, Docket No. ER15-1344 (Oct. 8, 2015) ("The technical conference will explore issues related to PJM's application of its Order No. 1000-compliant transmission planning process to local transmission facilities . . .").

334. *Monongahela Power Co., et al.*, 156 F.E.R.C. ¶ 61,134, at P 12 (2016).

335. *Monongahela Power Co., et al.*, 162 F.E.R.C. ¶ 61,129, at PP 74–77, 82 (2018).

solution" is for the IOU to replace an aging facility that it owns.[336] FERC rejected that argument, noting that merely replacing decades-old transmission lines with an identical facility fails to consider changes to the grid's topology and technological developments since the original facility was put into service.[337] Non-IOU PJM members told FERC that IOUs plan Supplemental Projects in "a vacuum, divorced from the broader RTEP planning process," and urged FERC to require full integration of the regional and local planning processes.[338] Hoping to "mitigate concerns that Supplemental Projects may be structured to avoid or replace regional transmission projects that would otherwise be subject to competitive transmission development under Order No. 1000,"[339] FERC ordered additional transparency. However, it denied the broader reforms requested by non-IOUs, including their request that IOUs be required to actually respond to stakeholder comments on local plans.[340]

While it remains to be seen whether the new local planning procedures lead to different outcomes, the proceeding did result in a clear win for the IOUs. FERC approved their proposal to transfer the provisions about local planning processes from the PJM Operating Agreement to the PJM OATT.[341] Recall that IOUs won a key legal victory following the conversion of PJM from a power pool to an ISO that validated IOUs' section 205 filing rights over transmission rate design.[342] Following that decision, FERC approved a settlement between PJM IOUs and PJM that provided IOUs with "exclusive and unilateral" rights to make section 205 filings about various matters in the OATT and left PJM with exclusive filing rights over the Operating Agreement.[343] By approving the move from the Operating Agreement to the OATT, FERC provided IOUs with unilateral authority to file amendments under section 205 to local planning processes.

PJM IOUs wasted little time in wielding their expanded filing authority to formalize additional carve-outs from competition. Addressing so-called "End-of-Life" (EOL) transmission projects, IOUs stated in a June 2020 filing that although "projects required to maintain, repair, or replace transmission facilities" are not subject to Order No. 890, they nevertheless proposed to voluntarily disclose information about these projects pursuant to the Supplemental Projects process outlined in the IOU-controlled tariff.[344] A stakeholder-endorsed counter proposal[345] would have added EOL planning to the PJM-controlled regional planning process in an attempt to ensure that the regional network is "developed with an eye toward the future, rather than simply rebuilding the grid of the past"[346] for the IOUs' financial

336. *Id.* at P 79.

337. *Id.* FERC also rejected IOUs' initial filing, finding that the processes their proposed tariff amendments would implement would violate Order No. 890. *Id.* at PP 100–104.

338. *Monongahela Power Co., et al.*, 164 F.E.R.C. ¶ 61,217, at P 23 (2018).

339. *Monongahela Power Co., et al.*, 162 F.E.R.C. ¶ 61,129, at P 108 (2018).

340. *Monongahela Power Co., et al.*, 164 F.E.R.C. ¶ 61,217, at PP 21–28.

341. *Monongahela Power Co., et al.*, 162 F.E.R.C. ¶ 61,129, at P 97.

342. *Supra* notes 134–138 and accompanying text.

343. *PJM Interconnection*, et al., 105 F.E.R.C. ¶ 61,294, at P 11 (2003).

344. PJM Transmission Owners' Transmittal Letter, Docket No. ER20-2046 (June 12, 2020).

345. PJM Transmittal Letter, Docket No. ER20-2308 (July 2, 2020).

346. Letter from PJM Stakeholders to PJM Chairman and PJM CEO (May 12, 2020) (on file with author).

and strategic gain. Their proposal would obligate IOUs to notify PJM six years in advance of a facility's end-of-life date, a requirement that PJM argues is intended to inform the regional planning process. This advanced notification also appears designed to reduce the number of projects developed through reliability-related exemptions from competition.

FERC accepted the IOUs' filing as just and reasonable, finding that their proposed tariff revisions would "provide[] greater transparency."[347] In a separate order, FERC rejected the stakeholder proposal.[348] In the orders, FERC applied its prior determination that projects "result[ing] in only incidental expansions of the transmission system" are not subject to the Order No. 890 planning principles.[349] FERC also decided that the IOUs did not transfer planning of so-called asset management projects to PJM in the foundational agreements between the parties.[350] Taken together, these conclusions provide PJM IOUs with unfettered discretion to rebuild the existing transmission network, free from planning oversight. IOUs in other RTOs likely have the same autonomy and would not even have to adopt the disclosure rules approved by FERC in these proceedings.

PJM and its IOU members have also added numerous exemptions to competition. In their Order No. 1000 compliance filing, they proposed to exempt from competition any project that PJM deemed necessary within three years for reliability reasons.[351] FERC agreed with the premise that competition might be infeasible for such time-sensitive projects but required PJM to disclose in each instance why it was invoking this exemption and provide stakeholders with opportunities to comment.[352] In 2020, FERC found that PJM's implementation of this exemption was not transparent and ordered PJM to follow the procedures in its tariff.[353] Stakeholders urged FERC to go further, arguing that IOUs conjured up these so-called "immediate needs" projects by failing to report system information to PJM in a timely fashion.[354] FERC declined to add new reporting requirements.[355]

PJM and its IOUs have also used cost allocation to shield projects from competition. Because FERC eliminated ROFRs only for projects whose costs are allocated regionally among RTO members,[356] removing a project category from regional cost allocation and allocating all costs to the local IOU leaves the ROFR in place, allowing the local IOU to develop all future projects in that category without any competitive process. In 2015, FERC rejected a PJM proposal (filed on behalf

347. *PJM Interconnection, et al.,* 172 F.E.R.C. ¶ 61,136, at P 88 (2020), *reh'g denied*, 173 F.E.R.C. ¶ 61,225 (2020).

348. *PJM Interconnection,* 173 F.E.R.C. ¶ 61,242 (2020).

349. *PJM Interconnection, et al.,* 172 F.E.R.C. ¶ 61,136, at P 89 (referencing *So. Cal. Edison Co*, 164 F.E.R.C. ¶ 61,160, at P 33 (2018); *Cal. Pub. Util. Comm'n v. Pac. Gas & Elec. Co.*, 164 F.E.R.C. ¶ 61,161, at P 68 (2018)); *PJM Interconnection,* 173 F.E.R.C. ¶ 61,242, at P 56.

350. *PJM Interconnection, et al.,* 172 F.E.R.C. ¶ 61,136, at P 83.

351. *PJM Interconnection*, 142 F.E.R.C. ¶ 61,214, at P 247 (2013).

352. *Id.* at PP 248–255.

353. *PJM Interconnection*, 171 F.E.R.C. ¶ 61,212 (2020).

354. Comments of Old Dominion Electric Cooperative, FERC Docket No. EL19-91, at 8 (Jan. 27, 2020); Comments of American Municipal Power, Inc., FERC Docket No. EL19-91, at 5–6 (Jan. 27, 2020).

355. *PJM Interconnection*, 171 F.E.R.C. ¶ 61,212, at PP 87, 90.

356. Order No. 1000-A, *supra* note 211, at P 430.

of its member IOUs) to remove so-called "Local Reliability Projects" from competitive development by allocating all costs to the host IOU.[357] In 2016, IOUs used their section 205 filing rights to propose allocating to the host IOU all costs of projects driven by certain local planning criteria.[358] The D.C. Circuit vacated FERC's approval and held that allocating costs of projects with regional benefits violates the cost-causation principle, which is a cornerstone of FERC's cost-allocation policies.[359]

IOUs in MISO, which has developed almost no transmission through competitive processes, have also used cost allocation to shift projects out of the competitive regional process.[360] Alongside various Order No. 1000 compliance filings, MISO and its IOUs jointly filed a proposal to remove "Baseline Reliability Projects" (BRP) from the regional cost allocation process and instead assign all costs of a BRP project to the IOU whose service territory hosts the project.[361] Following the change, the number of BRP projects and value of BRP projects ballooned, from an average of forty-seven projects per year valued at $340 million annually (2010–2013) to an average of eighty-five projects per year valued at $777 million annually (2014–2019).[362] Other non-competitive IOU projects similarly increased from $775 million per year (2010–2013) to $1.9 billion per year (2014–2019).[363] Meanwhile, regional projects dwindled from nearly $6 billion (total, 2010–2013) to just $300 million (total, 2014–2019).[364] In 2020, FERC rejected a complaint that argued allocating all BRP costs to a single IOU is inconsistent with the cost causation principle.[365]

In 2019, MISO and its member IOUs again sought to carve-out additional projects from competition by changing cost allocation rules.[366] The filing parties suggested that enhanced cost-benefit analysis under their proposed rules would

357. *PJM Interconnection, et al.*, 151 F.E.R.C. ¶ 61,172 (2015).

358. *PJM Interconnection*, 154 F.E.R.C. ¶ 61,096 (2016). In 2017, FERC approved an exemption filed by PJM for substation upgrades intended to address certain reliability violations. *See also* Letter Order, FERC Docket No. ER17-1619-001 (Oct. 11, 2017). FERC also approved an exemption filed by PJM for projects driven by reliability violations related to lower-voltage facilities. *PJM Interconnection*, 156 F.E.R.C. ¶ 61,132 (2016).

359. Old Dominion Electrical Cooperative v. FERC, 898 F.3d 1254 (D.C. Cir. 2018).

360. *Id*; *see also* Brattle Report, *supra* note 319, at 18 (noting less than 1% of total transmission investment from 2013 to 2017 were subject to competitive processes).

361. *MISO, et al.*, 142 F.E.R.C. ¶ 61,215 (2013), *aff'd*, MISO Transmission Owners, et al. v. FERC, 819 F.3d 329 (7th Cir. 2016).

362. Complaint of Coalition of MISO Transmission Customers, et al., FERC Docket No. EL20-19, at 31–32 (Jan. 21, 2020).

363. *Id.* "Other" projects are economic projects below 345 kV. All costs are allocated to the host IOU, and they are therefore developed without competition. *See* Complaint of LSP Transmission Holdings II, L.L.C., et al., FERC Docket EL19-79 (June 5, 2019) (noting that critics have argued that "there are not clear criteria and procedures for identifying and evaluating projects in this category nor a requirement that they be evaluated at all"). FERC denied the complaint while concurrently approving MISO's proposal to lower the threshold for regionally cost allocated projects from 345 to 230 kV. *LSP Transmission, et al.*, 172 F.E.R.C. ¶ 61,098 (2020).

364. Complaint of Coalition of MISO Transmission Customers, et al., *supra* note 362, at 31–32.

365. *Coalition of MISO Transmission Customers, et al., v. MISO*, 172 F.E.R.C. ¶ 61,099, at P 86 (2020).

366. MISO and MISO Transmission Owners Tariff Filing Transmittal Letter, FERC Docket No. ER19-1124 (Feb. 19, 2019).

lead to "greater opportunities for the identification" of projects that would be subject to competitive solicitations, but the proposal also included a new exemption that appeared to be designed to limit these new opportunities.[367] FERC rejected the reform package due its inclusion of another project category whose costs would not be regionally allocated even though MISO proposed to demonstrate regional benefits of each project within this category.[368] FERC found that this mismatch between regional benefits and local cost allocation was inconsistent with the cost-causation principle.[369] In early 2020, FERC rejected a similar proposal filed jointly by MISO and its member IOUs, again due to the mismatch between expected benefits and allocated costs.[370] FERC subsequently approved the third filing from MISO and its TOs, which did not propose to allocate all costs to the local IOU but did include a competitive exemption that might negate the potential expansion of competition.[371]

In ISO-NE, the RTO finally announced its first competitive solicitation process in December 2019.[372] While more than two-thirds of the region's transmission investment has been approved through the regional process,[373] all but one project were exempt from competition based on ISO-NE's carve-out for time-sensitive projects needed for reliability purposes.[374] In 2020, following its investigation into ISO-NE's use of this exemption, FERC concluded that the record did not support a finding that the relevant ISO-NE tariff provisions are unjust and unreasonable or that ISO-NE is implementing the tariff inconsistent with FERC's directions.[375] FERC brushed aside claims that the "exemption incentivizes transmission

367. *Id.* ("In light of these enhancements, there is a greater likelihood that additional Market Efficiency Projects will be identified and . . . such projects would be subject to the Competitive Developer Selection Process. To address the distinct possibility that engaging in a lengthy developer selection process may push the implementation of such projects past their need-by dates for reliability purposes, the Applicants propose a limited exception from the Competitive Developer Selection Process for Immediate Need Reliability Projects."). Protestors pointed out, however, that MISO did not include guardrails imposed by FERC on other RTOs' "immediate needs" exemptions in an attempt to limit their applicability. Protest of LSP Transmission, et al., FERC Docket No. ER19-1124

368. *MISO, Inc.*, 167 F.E.R.C. ¶ 61,258, at PP 56–64 (2019).

369. *Id.*

370. *MISO*, *Inc.,* 172 F.E.R.C. ¶ 61,100, at P 19 (2020).

371. *MISO, Inc.*, 172 F.E.R.C. ¶ 61,095 (2020).

372. ISO-NE, Boston 2028 RFP – Review of Phase One Proposals (Jul. 17, 2020), https://www.iso-ne.com/static-assets/documents/2020/07/final_boston_2028_rfp_review_of_phase_one_proposals.pdf.

373. Comments of New England State Agencies, FERC Docket No. EL19-90, at 8 (Jan. 24, 2020) ("[A]ll 30 projects were built or are being built by incumbent transmission owners rather than being bid competitively. As a consequence, ISO-NE is the last regional transmission operator to conduct a competitive transmission planning and procurement process."); Comments of the Connecticut Public Utilities Regulatory Authority, FERC Docket No. EL19-90, at 2 (Jan. 24 2020) ("the extensive, exclusive reliance upon the immediate need exemption has avoided introducing competition into the process of solving transmission needs"); Brattle Report, *supra* note 319, at 8, fig.2; Lon L. Peters, *Shareholders v. Ratepayers in New England*, 34 ELEC. J. 106904 (2021) ("Two decades of coordinated planning and investments have, implausibly, left the ISO in a situation where almost all grid investments are time-sensitive.").

374. Response of LSP Transmission Holdings, FERC Docket No. EL19-90, at 5 (Jan. 27, 2020).

375. *ISO New England*, 171 F.E.R.C. ¶ 61,211 at P 55 (2020).

owners to do short-term planning and partake in other behavior to avoid competition," responding that it "disagree[s] that these incentives themselves render the exemption unjust and unreasonable."[376]

FERC launched a similar inquiry into SPP's so-called "immediate-needs" exemption. FERC concluded that there was insufficient evidence to find that SPP's tariff was unjust and unreasonable or unduly discriminatory.[377] Nonetheless, as is the case for the other three multi-state RTOs, SPP has rarely utilized competitive processes. In October 2020, SPP completed its second competitive development process, selecting an IOU-affiliate to construct a $66 million project.[378] SPP had previously cancelled the only project it selected in its first competitive process.[379]

In New York, no project has been developed through the NYISO's planning process that identifies economically beneficial regional projects since FERC approved the process in 2008.[380] The market monitor has highlighted several technical deficiencies with the process that may "systematically undervalue projects," and has also argued that the need for approval by 80% of IOUs "may enable a small group of participants to block economic investments,"[381] a concern that was echoed by the American Antitrust Institute and competing transmission developers.[382] Finally, it is worth noting that CAISO has completed ten competitive solicitation processes as of March 2019.[383] By comparison, MISO, SPP, ISO-NE, and NYISO have completed just five competitive processes combined.[384]

To sum up, FERC has repeatedly undermined its own efforts to introduce competition into cost-of-service, planned transmission development. IOUs continue to exploit their unearned advantages to dominate transmission development.

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376. *Id.* at P 59.

377. *Southwest Power Pool,* 171 F.E.R.C. ¶ 61,213 (2020).

378. Southwest Power Pool, Press Release, *SPP Stakeholders Approve Transmission Plans and Improvements to Grid Operations* (Oct. 28, 2020), https://spp.org/newsroom/press-releases/spp-stakeholders-approve-transmission-plans-and-improvements-to-power-grid-operations/.

379. LS Transmission Holdings, Motion for Leave to Reply and Reply, FERC Docket No. EL19-92 (Mar. 26, 2020).

380. *New York Indep. Sys. Operator, Inc.,* 125 F.E.R.C. ¶ 61,068, at P 130 (2008), *order on reh'g*, 126 F.E.R.C. ¶ 61,320, at PP 35–36 (2009).

381. David B. Patton, Pallas LeeVanSchaik, Jie Chen, & Raghu Palavdi Naga, *2018 State of the Market Report for the New York ISO Markets*, POTOMAC ECON. (May 2019), https://www.nyiso.com/documents/20142/2223763/2018-State-of-the-Market-Report.pdf.

382. *See supra* notes 199–205 and accompanying text. *See also New York Indep. Sys. Operator, Inc.,* 143 F.E.R.C. ¶ 61,059, at P 232 (2013) (noting argument by transmission developers that the 80% supermajority voting rule is unduly discriminatory).

383. Judy Chang, *Cost Savings Offered by Competition in Electric Transmission*, BRATTLE GRP. (Nov. 19, 2019), https://pubs.naruc.org/pub/656DDB87-F249-7EBF-8516-9BBB7AA1FE5F.

384. *Id.*

V. TO TRIGGER FURTHER PLANNING REFORMS, FERC SHOULD DISCIPLINE IOU LOCAL TRANSMISSION SPENDING

> It is difficult to change the direction of large electric power systems—and perhaps that of large sociotechnical systems in general—but such systems are not autonomous. Those who seek to control and direct them must acknowledge the fact that systems are evolving cultural artifacts rather than isolated technologies. As cultural artifacts, they reflect the past as well as the present. Attempting to reform technology without systematically taking into account the shaping context and the intricacies of internal dynamics may well be futile. If only the technical components of a system are changed, they may snap back into their earlier shape like charged particles in a strong electromagnetic field. The field also must be attended to; values may need to be changed, institutions reformed, or legislation recast.[385]

The power sector has changed since the days when the benefits of unchecked IOU coordination outweighed the potential advantages of open competition. New technologies, market structures, operational methods, and public policy goals have since taken the industry into once unforeseeable directions. Transmission development should evolve to meet these needs. To the extent that there was ever any rationale for bestowing upon local monopolists the collective responsibility of shepherding the development of our interstate networks, those justifications are no longer valid. IOUs are creatures of the early twentieth century, designed to focus on their state-granted service territories. Their local purpose and local monopolies should not constrain the evolution of the nation's transmission systems. Twenty-five years ago, FERC finally confronted IOU transmission dominance, ordering reforms that restructured the industry. Ten years ago, FERC attempted to unleash competitive regional transmission development, but obstructionist IOUs, claiming entitlements to perpetual local transmission monopolies, have evaded competition by changing rules and retreating to non-competitive development processes. I propose that FERC spark bottom-up reforms by targeting IOU-run local planning.

Procedural reforms in Order No. 890 require IOUs to share information about their local plans in order to facilitate public participation and scrutiny. But FERC itself fails to examine IOUs' transmission development plans or subsequent investments. Implicitly, it relies on other parties to discipline IOU spending. This abdication of its core ratemaking authority is an unjustified giveaway to IOUs that biases them in favor of non-competitive local investments over larger scale projects or more cost-effective non-transmission technologies.[386]

FERC should reverse its longstanding adoption of a presumption that all transmission expenses are prudent[387] and replace it with a presumption that only capital expenditures committed pursuant to an independently administered planning process are prudent. For all other transmission expenses, FERC should place

385. HUGHES, *supra* note 51, at 465.

386. State transmission siting processes that require IOUs to demonstrate "need" for new infrastructure are no substitute for FERC's oversight. FERC is uniquely situated to review transmission investments holistically, rather than on a project-by-project basis as state siting authorities do. As FERC explained in Order No. 1000, a holistic review should consider whether local needs can be met more cost-effectively through the regional planning process than through IOUs' separate local projects.

387. *Iroquois Gas Transmission System, L.P.*, 87 F.E.R.C. ¶ 61,295, at p. 62,168 (1999) (quoting *Minnesota Power & Light Co.*, 11 F.E.R.C. ¶ 61,312, at pp. 61,644–45 (1980); *Id.* (stating that FERC adopted this policy as "a matter of procedural practice to ensure that rate cases are manageable").

the burden of proof to establish prudence back on IOUs in any section 205 filing seeking transmission rate increases.[388] FERC's prudence review is necessary to protect customers and ensure just and reasonable rates.[389] A heightened standard of review is sensible where FERC's planning oversight is less robust and the development process is controlled by the IOU seeking the rate increase.

To implement this policy change, FERC should craft a policy, embodied in a policy statement or developed through a rulemaking,[390] that delineates requirements of "independently administered" planning, outlines how IOUs can demonstrate prudence, and provides limited exceptions related to reliability, the dollar value of projects, or other metrics. The policy should also address how FERC's prudence review will apply to formula rates[391] and whether FERC will end, on a prospective basis, its policy allowing state regulation of transmission rates when they are included as part of a bundled retail rate.[392] Placing the burden on IOUs is clearly within FERC's legal authority. Section 205 explicitly states that an IOU seeking to increase rates has the burden to prove that its proposal is just and reasonable.[393] FERC ought to insist that IOUs meet the statute's explicit command by proving prudence in their section 205 filings.

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388. IOUs and planning entities should only be pursuing prudent transmission investments. FERC should disclaim recent statements that suggest prudence and planning are not one in the same. *See, e.g., Cal. Pub. Utils. Comm'n v. Pac. Gas & Elec. Co.*, 164 F.E.R.C. ¶ 61,161, at P 34 (2018) ("This is a concern about self-interest as a cause of imprudent investment, which is subject to review in the ratemaking process and, as such, is ancillary to the transmission planning process.").

389. Paul L. Joskow, *supra* note 247, at 13 ("For all intents and purposes the FERC [transmission] regulatory process is a model of cost pass-through regulation with little scrutiny of costs.").

390. FERC's current prudence policy is nearly four decades old. *See New England Power Co*., 31 F.E.R.C. ¶ 61,047 (1985), *reh'g denied*, 32 F.E.R.C. ¶ 61,112 (1985). FERC has a well-established process for developing policy guidance through notice-and-comment procedures. *See, e.g., Inquiry Regarding the Commission's Policy for Determining Return on Equity*, 171 F.E.R.C. ¶ 61,155, at PP 1–17 (2020). Because policy statements are "not binding" on FERC, *see* Consolidated Edison Co. v. FERC, 315 F.3d 316, 319 (D.C. Cir. 2003); Interstate Natural Gas Ass'n of Am. v. FERC, 285 F.3d 18, 59 (D.C. Cir. 2002), a policy statement may provide FERC with more flexibility to tailor its approach as it develops more experience with its new prudence policy.

391. "With formula rates, the formula itself is the rate, not the particular components of the formula, such as the ROE. Thus periodic adjustments made in accordance with the Commission-approved formula do not constitute changes in the rate itself and accordingly do not require section 205 filings." *Ocean State Power II*, 69 F.E.R.C. ¶ 61,146, at p. 61,544 (1994). IOUs with formula rates would not need to make a section 205 filing to increase rates to reflect a larger ratebase due to transmission expansion.

392. *See, e.g., In Re Joint Application for the Transfer of Ownership and Control of Entergy Mississippi's Transmission Facilities*, Mississippi Public Service Commission, Docket No. 2012-UA-358, at P 43 (Dec. 10, 2013) (explaining that MISO's "bundled load exemption" exempts a vertically integrated IOU from certain MISO transmission charges and allows it reserve the portion of the its transmission revenue requirement that is designated to native load to state regulation, thus allowing state regulators to determine the rate of return on those transmission assets and review prudence). I recognize that preempting state regulation may be too controversial and might run the risk of sidetracking FERC's new prudence policy. It would be worth investigating the proportion of new transmission investments that is, in practice, regulated by states.

393. 16 U.S.C. § 824d(c) ("At any hearing involving a rate or charge sought to be increased, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the public utility . . . "). FERC has authority to deny inclusion of an IOUs' transmission investments. *See Public Service Co. of New Mexico*, 75 F.E.R.C. ¶ 61,266, at p. 61,859 (1996) (stating that FERC's policy of equally sharing prudently incurred cancelled plant costs between ratepayers and shareholders applies to transmission investments and requiring the IOU to file revised rates that reflect inclusion of only 50% of the project's costs).

The specter of FERC's prudence review could have significant effects on transmission planning. Ideally, FERC's policy would convince IOUs to place all transmission planning — regional and local (subject to carve-outs allowed under the policy) — under the control of an independent entity.[394] In transmission operations, separating ownership from operational control allowed the industry to capture benefits of both coordination and competition. Separating ownership from control over planning could have similarly significant benefits by untethering planning from IOU's state-granted advantages. In addition, unifying local and regional planning could finally achieve the promise of Order No. 1000 by leading to more cost-effective portfolios of projects.[395]

FERC should take three additional steps to enhance the independence of transmission planners. First, FERC should reduce planners' reliance on IOUs for information, which might free RTOs from a measure of undue influence that IOUs may currently be able to exert on the planning process. FERC should require IOUs to disclose all transmission information relevant to planning processes and, where transmission is independently planned, mandate that planners independently verify the accuracy of that information.[396] Second, FERC should order

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394. Opponents of independent planning might argue that FERC does not have authority to regulate entities in non-RTO regions because they that are not "public utilities" under the FPA. In non-RTO regions, the regional planning entities do not file tariffs with FERC. IOUs participating in those regional processes met their Order No. 1000 obligations by amending their own OATTs. *See, e.g., Avista Corp., et al.,* 143 F.E.R.C. ¶ 61,255 (2013). These regional planning entities do not meet FERC's "independence" criteria. Two of these six entities are governed by their member utilities. Three are run by boards with utility and stakeholder members. The remaining organization, ColumbiaGrid, has an independent board appointed by its member utilities, although each of the three current board members is a recently retired executive of a member utility. Review of Recent Regional Plans, *supra* note 197, at 7; https://www.columbiagrid.org/board-of-directors.cfm. FERC might take one of two approaches to regulating these entities. First, it could continue its practice of regulating regional planning through member IOU filings. While IOUs would retain section 205 rights, they could create procedures that would require them to defer to independent management of the planning entity. Should FERC find that IOUs are interfering with the planning entity, it could conclude that the planning process is not independent and therefore require IOUs to demonstrate prudence. Second, FERC could instead adopt the approach it articulated in the RTG policy statement, where it concluded that although RTGs were not public utilities, their agreements "affect or relate to jurisdictional transmission rates or services" and therefore must be filed under section 205. RTG Policy Statement, *supra* note 217, at 41,629.

395. IOUs might argue that local transmission remains a natural monopoly because having a single entity physically operate all of the local transmission facilities is more cost-effective than having numerous entities Coordinate the local transmission assets that each company owns. FERC has broad jurisdiction over all transmission facilities and could potentially replicate its open-access mandate for the physical operation of transmission facilities. It might order IOUs, which typically operate local transmission control rooms, to offer to contract with other owners for the physical operation of their facilities.

396. RTOs currently verify performance characteristics of generation and demand-side resources but may not have similar practices with regard to transmission infrastructure. *See, e.g., PJM Interconnection*, 171 F.E.R.C. ¶ 61,210 (2020) (approving tariff amendments that "will enhance the testing requirements for Demand Resources and Price Responsive Demand . . . to better reflect true load reduction capabilities during actual event conditions"); *PJM Interconnection*, 172 F.E.R.C. ¶ 61,055 (Glick concurring) (noting that FERC has "recently required PJM to include in its tariff a provision that would require Market Sellers to submit accurate ramp rates"); *TranSource v. PJM*, 168 F.E.R.C. 61,119 at PP 154–157 (2019) (noting that the PJM tariff does not require PJM to verify IOU-provided transmission facility ratings).

planners to engage third-party evaluators to oversee the project selection process.[397] Third, where planners use the solicitation model to select project developers, FERC should require them to hand that function to a third party. RTOs and other planning entities may be ill-equipped to evaluate development proposals, particularly where their IOU members are competing against other companies.

Even if FERC's new prudence policy does not induce IOUs to cede planning decisionmaking authority, it may still mitigate IOU transmission dominance. Prudence reviews might include state regulators, consumer advocates, generation developers, rival transmission companies, and entities advocating for deployment of technologies that can obviate new transmission. Information provided by these parties and scrutinized by FERC staff may cause IOUs to propose different projects than they otherwise would. I suspect that, with money on the line, IOUs might disclose more information than they already do pursuant to Order No. 890.

FERC could reject IOU project proposals if it has evidence that consumers would be better served by more cost-effective alternatives. This more pro-active prudence policy would cast FERC as the central planner, a role that it may not be suited to play. To pull it off, it might need additional staff, perhaps housed in a new office dedicated to transmission oversight.[398] The goal of the policy, however, is not to plan all transmission development in Washington, D.C., but to spur improvements to planning processes around the country administered by independent entities.

FERC's prudence policy could also partially mitigate the effects of discriminatory state laws that impede non-IOU transmission development. Following Order No. 1000, several states in the MISO and SPP regions enacted right-of-first refusal laws.[399] For example, Minnesota's ROFR law grants IOUs and other owners of in-state transmission lines rights to build any project planned by MISO that connects to the incumbent transmission owner's facilities within the state's boundaries. When the incumbent utility invokes its ROFR, FERC could establish a presumption that the utility's investment is imprudent unless the utility adopts the terms and conditions proposed by the developer awarded the project by the RTO through its competitive process. This presumption would undoubtedly benefit consumers, as it would effectively force IOUs to either adopt terms and conditions that result from a competitive process or it would lead IOUs to decline to exercise

397. Order No. 1000, *supra* note 189, at P 330 (declining to adopt this suggestion); *but see* Order No. 872, *Qualifying Facility Rates and Requirements*, 172 F.E.R.C. ¶ 61,041, at PP 413, 435 (allowing states to set avoided cost rates under PURPA through competitive solicitations and requiring oversight of such solicitations by an "independent administrator").

398. Energy law scholar Richard Pierce has explained that:

> [i]n order to succeed, any attempt to establish the imprudence of a utility's decision to construct a new plant would require extraordinarily large expenditures for the services of lawyers, economists, and engineers. Litigation costs of this magnitude exceed the resources available to most of the consumer groups and governmental bodies that participate in rate cases. Thus, the fact that utility decisions to build new plants are rarely held to be imprudent does not necessarily support an inference that virtually all such decisions are prudent.

Richard J. Pierce, *The Regulatory Treatment of Mistakes in Retrospect: Cancelled Plants and Excess Capacity*, 132 UNIV. OF PENN. L. REV. 497, 512 (1984).

399. *See* Neb. Rev. Stat. §70-1028; N.D. Cent. Code §49-03- 02.2; S.D. Codified Laws §49-32-20; Tex. Utils. Code §37.056(e)-(f); 17 Okla. Stat. §292; Ind. Code §8-1-38-9(a)-(b); Iowa H.F. 2653, Div. XXXIII (2020).

their state ROFRs when they are unwilling to adopt competitively determined terms and conditions.

If IOUs do not voluntarily cede planning to an independent entity, FERC could force IOUs to do so. To justify this move, FERC could point to its recent orders on minimum offer price rules (MOPRs) in capacity markets. In several orders, FERC claimed that to ensure just and reasonable capacity rates it must nullify advantages that states provide to particular resources that offer into the auction.[400] While there are numerous factual differences between capacity auctions and transmission development, FERC has identical legal authority under section 206 to remedy unjust and unreasonable rates caused by advantages conferred on particular market participants by state law.[401] Applying the MOPR logic to transmission planning, FERC could neutralize advantages that IOUs have in transmission development that are traceable to their exclusive service territories, captive ratepayers, and discriminatory siting laws.

If it chooses not to exercise its newly discovered power to nullify the economic effects of state laws (or if FERC reverses course on MOPRs), FERC could argue that the D.C. Circuit decision rejecting challenges to Order No. 1000 provides a sufficient legal basis for further reforms, including efforts to mitigate IOU advantages in local planning processes. The D.C. Circuit's decision affirmed that FERC has broad discretion to define unduly discriminatory conduct and remedy such conduct in transmission planning processes.[402] The court did not limit FERC's broad authority to regional planning or establish any legal barrier that prevents FERC from imposing new procedures in local planning, requiring planning be independently administered, or subjugating IOUs' local planning outcomes to the regional process.

Regardless of whether FERC mandates independent planning or IOUs voluntarily join independently run planning organizations, the efficacy of FERC's reforms depend in part on states' cooperation. Many states have been willing participants in IOU efforts to stifle competition.[403] Using their nearly exclusive authority over transmission siting, states can effectively veto pro-competitive reforms by refusing to provide siting permission to a non-IOU or out-of-state

400. *See, e.g., Calpine Corp., et al., v. PJM,* 169 F.E.R.C. ¶ 61,239 (2019), *reh'g denied,* 171 F.E.R.C. ¶ 61,035 (2020).

401. It remains to be seen whether FERC's order will be upheld in federal court. Litigation is pending as of publication of this article. Illinois Commerce Comm'n. et al., v. FERC, Seventh Cir. Docket No. 20-01645.

402. *See* South Carolina Pub. Serv. Authority v. FERC, 762 F.3d 41, 57–69 (D.C. Cir. 2014) (upholding Order No. 1000 in part due to the FPA's "broadly stated" authority to remedy anti-competitive practices even where FERC's action is premised on a "theoretical threat" to just and reasonable rates, such as the absence of competition); *see also* Eisen, *supra* note 22; Ari Peskoe, *Easing Jurisdictional Tensions by Integrating Public Policy in Wholesale Electricity Markets*, 38 ENERGY L.J. 1 (2017).

403. FERC's efforts to facilitate development of competitive power markets illustrate the importance of complementary state action. By 1999, three years after FERC issued Order No. 888, all but one state within the three former northeastern tight power pools enacted legislation or took administrative action to restructure utilities. Texas and California also enacted their own restructuring laws. By ordering or incentivizing utilities to sell their power plants or spin-off their generation assets into an affiliated company, state restructuring efforts seeded burgeoning wholesale markets with non-IOU power suppliers and created demand for wholesale power. Following restructuring, IOUs that had relied on their own power plants to supply captive ratepayers had to turn to the wholesale market to meet local demand.

developer. Indeed, numerous states, often with IOU support,[404] have blocked non-IOU transmission development by providing IOUs with ROFRs,[405] refusing to site non-IOU projects,[406] and rejecting innovative merchant projects that do not align with traditional notions of the "public convenience and necessity" standard that regulators must meet in order to provide siting permission.[407]

Congress could preempt state siting authority or at least prevent states from enforcing their most anti-competitive laws, such as ROFRs. In 2005, in its first major energy legislation since FERC issued its Open-Access mandate, Congress provided FERC with limited authority to site transmission lines in areas designated by the Department of Energy as having transmission congestion or capacity constraints.[408] FERC has never used this siting authority successfully, in part because a federal appeals court interpreted the provisions narrowly.[409]

In the same bill, Congress also repealed Part I of the 1935 Public Utility Act, paving the way for a wave of utility mergers and perhaps ushering in a new era of IOU transmission dominance.[410] The twenty largest U.S.-based publicly traded transmission owners (as measured by miles) have a combined market capitalization of nearly $700 billion (not including Berkshire-Hathaway, the second largest transmission owner that itself is valued at more than $500 billion).[411] These companies' assets are increasingly reliant on cost-of-service ratemaking as several companies have shed competitive lines of business.[412] Suffice it to say, these

404. *See supra* note 259; *see also* Brief of the Edison Electric Institute, *LSP Transmission Holdings v. Sieben*, Docket No. 18-2559 (8th Cir. Jan. 14, 2019) (supporting Minnesota's ROFR law).

405. *See, e.g.,* LSP Transmission Holdings v. Sieben, et al., 954 F.3d 1018 (8th Cir. 2020) (affirming lower court's dismissal of Dormant Commerce Clause Challenge to Minnesota's ROFR law, which was enacted in 2012).

406. *See, e.g.,* Illinois Landowners All., NFP v. Illinois Commerce Comm'n, 90 N.E.3d 448 (2017) (holding that regulators are prohibited from granting a certificate of convenience and public necessity to a merchant transmission company because it was not a "public utility" under state law); Iowa Senate File 516, Secs. 55–60 (2016) (preventing merchant developers from acquiring land via eminent domain); Ark. Code § 23-3-205 (prohibiting regulators from issuing a certificate to anyone other than a public utility or an entity designated by an RTO).

407. *See, e.g.,* Missouri Public Service Commission, Report and Order, File No. EA-2014-0207 (July 1, 2015) (rejecting Grain Belt Express); Arkansas Public Service Commission, *In the Matter of the Application of Plains and Eastern Clean Line LLC*, Docket No. 10-041-U (Jan. 11, 2011) (rejecting Plains and Eastern line).

408. Energy Policy Act of 2005, Pub. Law. No. 109-58, § 1221 (2005).

409. Piedmont Environmental Council v. FERC, 558 F.3d 304 (4th Cir. 2009).

410. *See* Scott Hempling, *Inconsistent with the Public Interest: FERC's Three Decades of Deference to Electricity Consolidation*, 39 ENERGY L. J. 233, 251 (2018) (finding that 13 holding companies own what used to be 82 independent IOUs, and only 18 IOUs are remain unconnected to other IOUs).

411. Calculation based on market capitalizations as of January 1, 2021, as reported by finance.yahoo.com. Transmission ownership is derived from FERC Form 1 data, as compiled by Catalyst Cooperative. Zane A. Selvans and Christina M. Gosnell, FERC Form 1 Database v 1.0.0 (1994-2018), ZENODO (2020), https://zenodo.org/record/3677548#.YGyaMBRuc-Q. Note that some major transmission owners are not U.S. based, including Avangrid (owned by Spanish company Iberdrola) and Fortis (Canada). American Transmission Company is privately owned.

412. Conor Harrison, *Electricity Capital and Accumulation Strategies in the U.S. Electricity System*, ENV'T AND PLANNING E: NATURE AND SPACE (Aug. 27, 2020), https://journals.sagepub.com/doi/10.1177/2514848620949098 ("Despite their flight from merchant markets, investor owned electricity holding companies are not shrinking. Rather, utilities are using the funds raised from the sale of their deregulated businesses to acquire and/or invest in other regulated assets in order to meet financial analysts' expectations for earnings increases."

mega-IOUs and their counterparts[413] are likely to oppose Congressional action that opens transmission to competition or in some way dilutes IOU control over local transmission development.

With states and Congress seemingly unwilling to oppose IOU dominance, FERC appears most likely to take further action. Yet, I acknowledge that IOUs will inevitably (and rationally) resist further FERC reforms designed to chip away at their transmission dominance. Efforts to dismantle the IOU transmission development "cartels"[414] may be delayed through litigation and weakened through implementation. Recognizing the inevitability of IOU backlash, FERC might instead choose to rescind its competitive mandate and direct its reforms towards substantive outcomes, such as motivating more regional investment or incentivizing deployment of new technologies. In that vein, FERC might impose certain technical analyses in the planning process that will cause IOUs and RTOs to select the "right" projects[415] or establish particular goals for regional plans to achieve, such as unlocking new resources or connecting regions. Rules that directly target substantive results may have the side-benefit of addressing IOU dominance by ensuring that projects that harm a particular IOU's parochial interests are nonetheless developed, provided they meet FERC's technical standards.

Replacing Order No. 1000's pro-competition procedural reforms with substantive rules engineered to drive IOU investment into FERC-preferred projects may well mitigate IOU backlash and therefore lead to more regional transmission spending, at least in the short term.[416] It is worth noting that RTO transmission planning efforts held up as gold standards — MISO's Multi-Value Projects (MVP) and SPP's Priority Projects[417] — were approved by RTO boards prior to Order No.

The author observes that these developments have "placed an increasing emphasis on regulatory affairs, as success in the regulatory arena continues as a key accumulation strategy for utilities."); CNBC, SHARES OF FIRSTENERGY SOAR AFTER EMBATTLED UTILITY GETS INVESTMENT FROM ACTIVIST ELLIOTT MANAGEMENT (Jan. 22, 2018) (noting the company's plan to sell its merchant generation assets and quoting FirstEnergy CEO noting the company's plan to "transform FirstEnergy into a fully regulated utility"); Sonia Patel, *How Eight Major Power Companies Are Dealing with Market Turmoil*, POWER (Oct. 31, 2017) (reporting that Duke and AES had sold off their merchant assets and AEP had sold more than half of its merchant fleet); Jared Anderson, *PSEG Considers Shedding Its Non-Nuclear Assets; Cutting Merchant Generation*, S&P GLOBAL (July 31, 2020) (quoting company CEO: "Our intent is to accelerate the transformation of PSEG into a primarily regulated . . . utility."); Lorraine Mirabella, *Exelon, Owner of Baltimore-based Constellation and BGE, Will Split Power and Utility Businesses*, BALTIMORE SUN (Feb. 24, 2021) (reporting that Exelon's board approved a plan to split into two separate, publicly traded companies).

413. U.S. based and publicly traded IOUs with large market capitalizations that are not among the top 20 transmission owners (measured by total miles) include PSE&G ($29.5 billion) and ConEd ($24.2 billion).

414. MISO Transmission Owners, et al. v. FERC, 819 F.3d 329, 335 (7th Cir. 2016) (in upholding FERC's order removing MISO's ROFR, the Seventh Circuit likened RTOs to cartels, in that their members "are seeking to protect themselves from competition from third parties" in transmission development).

415. *See, e.g.,* Burcin Unel, *A Path Forward for the Federal Energy Regulatory Commission*, INST. FOR POLICY INTEGRITY (Sept. 2020) (recommending that FERC require "comprehensive cost-benefit analysis" in transmission planning).

416. *See, e.g.,* Order No. 1000, *supra* note 189, Commissioner Moeller, dissenting in part (criticizing the scope of the Rule's MOPR elimination and concluding that "instead of encouraging more regional cooperation, the rule could ultimately discourage such cooperation by encouraging more local transmission projects").

417. *See, e.g.,* Jay Caspary, Michael Goggin, Rob Gramlich, Jesse Schneider, *Disconnected: The Need for a new Generator Interconnection Policy*, at 21 (Jan. 2021), https://cleanenergygrid.org/wp-content/uploads/2021/01/Disconnected-The-Need-for-a-New-Generator-Interconnection-Policy.pdf.

1000 and therefore parceled out projects to IOUs without competition.[418] Nonetheless, I suggest that while substantive reforms may be necessary, they will be insufficient, and FERC should continue to focus its reforms on IOU transmission dominance for three reasons.

First, FERC has never attempted to dictate substantive outcomes and has in fact explicitly disclaimed that goal.[419] Any rule that aims to influence substantive outcomes would have to be robust enough that planners would be unable to subvert FERC's goal by tailoring the analysis or filtering the results with additional studies designed to either benefit IOUs or achieve results contrary to FERC's goals. FERC would also run the risk that its rule simply will not work and might result in unintended outcomes.

Second, addressing IOU transmission dominance through procedural reforms aligns with FERC's expertise, experience, and legal authority. FERC derived its comparability, information transparency, and independence principles from its statutory duty to remedy unduly discriminatory IOU practices and prescribed them as antidotes to IOUs' anticompetitive behavior. While these principles have proven adaptable, they have not yet liberated transmission development from IOU dominance. Nevertheless, I believe that procedural reforms are necessary, even if FERC also issues substantive rules designed to achieve particular planning goals.

Third, as I have documented throughout this article, IOUs have used their unearned advantages to thwart the development of competitive power markets and transmission development processes. They continue to have incentives and abilities to develop interstate networks that reflect their parochial interests. They are designed to thrive under the status quo, and are ill-suited and unmotivated to facilitate new market entrants and unleash the competitive forces that can allow the sector to realize its innovative potential. Relegating IOUs to participants in the planning process on equal footing with other companies is a necessary step.

Finally, I do not believe that independently administered planning will be a panacea that instantly unlocks innovative transmission projects. Other reforms, particularly to interconnection processes, may be necessary as well.[420] FERC

418. *Southwest Power Pool*, 131 F.E.R.C. ¶ 61,252, at P 7 (2010); *Midwest Independent System Operator,* 133 F.E.R.C. ¶ 61,221 (2010).

419. Order No. 1000, *supra* note 189, at P 149. *South Carolina Pub. Serv. Auth.*, 762 F.2d at 57–58 (FERC "disavowed that it was purporting to 'determine what needs to be built, where it needs to be built, and who needs to build it.' As the Commission explained on rehearing, 'Order No. 1000's transmission planning reforms are concerned with process' and 'are not intended to dictate substantive outcomes.'").

420. *See MISO*, 174 F.E.R.C. 61,084 (2021) (Commissioner Clements, concurring) ("[I] am concerned that the status quo in MISO risks discrimination by transmission owners" in the interconnection process); *MISO*, 172 F.E.R.C. ¶ 61,248 (2020) (Commissioner Glick, dissenting) ("I remain concerned . . . that the Commission's determination on remand will provide an opportunity for transmission owners to favor their own generation and create an environment where similarly-situated interconnection customers pay higher network upgrade costs . . . ."); *Anbaric Development Partners v. PJM*, 171 F.E.R.C. ¶ 61,241 (2020) (denying complaint filed by merchant transmission developer about PJM interconnection rules and setting issues for technical conference); *TranSource v. PJM*, 168 F.E.R.C. ¶ 61,119 (2019) (reversing ALJ's conclusion that PJM interconnection practices were non-transparent and unduly discriminatory but finding PJM's tariff omits material terms on interconnection studies and that PJM made errors in processing interconnection studies); Caspary, et al, *supra* note 417.

might also consider expanding the scope of its independence principle, in part by revisiting allocations of filing rights between RTOs and IOU members.[421]

VI. CONCLUSION

FERC-set rates support the development of more than $20 billion of transmission facilities each year.[422] This safe investment opportunity is available primarily — in fact, nearly exclusively — to IOUs. Their incentives to protect their superior access to this lucrative arrangement drive a defensive approach to transmission development that prioritizes projects that they can build without competition and with little oversight. This development model breeds collusion among IOUs who promote transmission rules designed to shield their state-granted territories from outside developers.

FERC's efforts to break up the IOU transmission clubs have not yet pried control over transmission development from IOUs. FERC's comparability and transparency principles have mitigated IOU transmission dominance but, without further reforms, the IOU transmission syndicate may indeed be forever. To foster innovation and facilitate development of interstate networks that meet twenty-first century needs, FERC should disentangle transmission planning from IOUs' financial and strategic interests.

421. *Supra* notes 136–138 and accompanying text.

422. Edison Electric Institute, *supra* note 213, at 23.

MOPR MADNESS

Joshua C. Macey & Robert Ward

Synopsis: Five years ago, in his piece on capacity markets, Jay Morrison discussed what he then viewed as the anticompetitive and arbitrary aspects of FERC's shifting Minimum Offer Price Rules (MOPR) and their interference with private ordering and state policymaking. MOPRs allow administrative bodies, rather than market participants, to determine the minimum price per kilowatt that generators can submit as capacity market bids. Since then, energy regulators have extended MOPRs to an increasing number of market participants, and critiques of these rules have reached a fever pitch. To say that the latest permutation of price mitigation promotes a cure worse than the disease suggests that the latest iterations of the MOPR rule is not curing anything at all.

Given the controversy MOPRs have generated, it is worth considering what distortions, if any, MOPRs remedy. The standard defense of MOPRs is that they enable perfectly competitive markets that match physical power flows to system needs. At different points in the past fifteen years, FERC has suggested that MOPRs mitigate buyer market power, counteract price suppression, and ensure resource adequacy. Yet on closer inspection, none of these justifications withstands scrutiny. As this Article shows, buyer market power is the only market failure for which MOPRs might be an appropriate remedy. That is because buyer market power creates a market for lemons problem because it threatens to drive independent power producers out of wholesale markets. But even that remains merely a theoretical problem, since FERC has never explained why buyer market power distorts wholesale electricity markets or offered proof that net buyers are exploiting their market power. The reality is thus that MOPRs constitute a step backwards towards the old practice of administrative pricing. In attempting to create ideally competitive markets, FERC has developed a resource procurement process that favors incumbent merchant generators and harms investor-owned utilities, member-owned cooperatives, and state-supported resources.

It is ironic, then, that a market intervention that was designed to support competition is now preventing resources from competing with each other. A superior approach is to break up vertically integrated electric utilities and prohibit the types of contracts that facilitate market power abuses. Alternatively, FERC could bring aggressive enforcement actions against buyers that manipulate electricity markets.

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I. INTRODUCTION

Five years ago, Jay Morrison wrote in these pages that "buyer-side market power mitigation mechanisms"—a controversial policy in which administrative bodies, rather than market participants, determine the minimum price per kilowatt that generators can submit in capacity markets[1]—"are incapable of accomplishing the goals for which they were adopted."[2] Since then, a number of prominent voices in the energy community have joined Morrison's critique, including at least three

1. *See*, *e.g.*, Catherine Morehouse, *PJM MOPR Could Cost Market Consumers up to $2.6B Annually, Report Finds*, UTIL. DIVE (May 19, 2020), https://www.utilitydive.com/news/pjm-mopr-could-cost-market-consumers-up-to-26b-annually-report-finds/578183/.

2. Jay Morrison, *Capacity Markets: A Path Back to Resource Adequacy*, 37 ENERGY L. J. 1, 5 (2016).

FERC Commissioners,[3] multiple state public utility commissions,[4] legal and economic scholars who study electricity markets,[5] and even grid operators charged with implementing price mitigation rules.[6] Recent MOPR reforms are expected to cost consumers billions, keep unneeded generation in the market, and impede state decarbonization efforts.[7] And this opposition to MOPRs seems to have had an effect, as Chairman Richard Glick recently acknowledged that "[t]here's recognition that the MOPR process in general is just not sustainable."[8]

But given the strong opposition MOPRs have inspired, it is important to understand why this administrative intervention was initially developed and how it expanded during its short and controversial life. The standard defense of MOPRs is that they allow capital to compete in precisely engineered markets that match

3. For example, in December 2019, FERC Commissioner Richard Glick wrote that an intervention that was ostensibly designed to support competitive electricity markets would "[d]ramatically increas[e] the price of capacity . . . and slow[] the region's transition to a clean energy future." Glick was writing about a controversial policy called a "minimum offer price rule" (MOPR). Dissenting from an earlier MOPR Order, Commissioner LaFleur wrote that the Commission's proposal would enact "the most sweeping changes to the PJM capacity construct since the market's inception more than a decade ago." *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 F.E.R.C. ¶ 61,236 (2018) (June 2018 Order). And Chairman Bay registered his concern a year earlier. See *New York State Pub. Serv. Comm'n v. New York Indep. Sys. Operator, Inc.,* 158 F.E.R.C. ¶ 61,137 (Comm'r Bay, concurring) (2017).

4. *See*, *e.g.*, Catherine Morehouse, *Ditching PJM Capacity Market Could Cost New Jersey $386M Through 2022, Market Monitor Finds*, UTIL. DIVE (May 15, 2020), https://www.utilitydive.com/news/ditching-pjm-capacity-market-could-cost-new-jersey-386m-through-2022-mark/577998/ (discussing opposition to the PJM capacity market reforms in New Jersey, Illinois, and Maryland); *see also* Patrick Skahill, *CT Taking 'A Serious Look' at Exiting Regional Power Market*, THE CT MIRROR: ENV'T (Jan. 16, 2020), https://ctmirror.org/2020/01/16/conn-taking-a-serious-look-at-exiting-regional-power-market/ (quoting Katie Dykes, the Connecticut Commissioner of Energy and Environmental Protection, saying:

> We are at the mercy of a regional capacity market that is driving investment in more natural gas and fossil fuel power plants that we don't want and we don't need. . . . This is forcing us to take a serious look at the cost and benefits of participating in the ISO New England markets.

5. *See*, *e.g.*, Danny Cullenward & Shelley Welton, *The Quiet Undoing: How Regional Electricity Market Reforms Threaten State Clean Energy Goals*, YALE J. ON REGULATION (Nov. 8, 2019), https://www.yalejreg.com/bulletin/the-quiet-undoing-how-regional-electricity-market-reforms-threaten-state-clean-energy-goals/ (arguing that MOPRs "present a serious threat to states' autonomy over their energy mix"); *see also* Sylwia Bialek & Burcin Unel, *Efficiency in Wholesale Electricity Markets: On the Role of Externalities and Subsidies*, CESifo Working Paper No. 8673, at 27 (Nov. 2020), https://papers.ssrn.com/sol3/Delivery.cfm/8673.pdf?abstractid=3727748&mirid=1 (arguing that "generation subsidies do not lead to price suppression in the capacity markets" and that MOPRs "are not supported by economic theory"); Michael Goggin & Rob Gramlich, *A Moving Target: An Update on the Consumer Impacts of FERC Interference with State Policies in the PJM Region*, Grid Strategies, LLC, 2-3, 5-6, 8-9 (May 2020), https://gridprogress.files.wordpress.com/2020/05/a-moving-target-paper.pdf (projecting the costs of MOPR reforms in PJM); *Comments of the Institute for Policy Integrity at New York University School of Law re: Cricket Valley Energy Ctr. v. N.Y. Indep. Sys. Operator, Inc.*, FERC Docket No. EL21-7-000, 10 (Nov. 18, 2020) ("Not only is evidence of capacity market price suppression absent from the Complaint, our own analysis of mechanisms underlying electricity markets identifies affirmative evidence that the effects of state policies play out in *energy* markets rather than putting downward pressure on capacity prices.") (emphasis in original).

6. *See*, *e.g.*, *Request for Rehearing and Request for Clarification of PJM Interconnection, L.L.C. re: Calpine Corp. v. PJM Interconnection, L.L.C. Decision*, FERC Docket Nos. ER18-1314-000, 4 (Jan. 21, 2020) (PJM, the grid operator charged with serving sixty-five million Mid-Atlantic electricity consumers, complaining that the December 2019 MOPR reform in its region "may have paradoxically unintended consequences over time and may result in less economic efficiency").

7. *See infra* Part III. *See also* Morehouse, *supra* note 1.

8. Arianna Skibell, *FERC: Glick Unveils Environmental Justice, Climate Plans*, E&E NEWS (Feb. 12, 2021), https://www.eenews.net/stories/1063725039.

physical power flows to system needs.[9] Buyer-side market power mitigation rules emerged, as the name implies, to prevent net buyers from abusing their market power.[10]

Since 2006, price mitigation rules have expanded both in scope and in restrictiveness, applying to ever-more resources and granting energy regulators evermore control over the terms and conditions of capacity market participation. This transformation occurred in three stages. First, in the mid-2000s, FERC and grid operators created offer floors to prevent net buyers of capacity from manipulating capacity markets, though the Commission did not explain why buyer market power was a problem or offer proof that buyers were abusing their market power.[11] Second, in 2011, electricity regulators eliminated screens that ensured that price floors applied only to resources that had both the incentive and the ability to manipulate capacity markets.[12] In that period, FERC continued to cite buyer market power to justify price mitigation rules, though the Commission never explained the connection between state subsidies and buyer market power.[13] Third, by 2018, buyer-side market power mitigation became something of a misnomer. Recent capacity market reforms treat all revenue that does not originate in FERC-regulated wholesale markets as problematic. At this point, FERC largely abandoned the buyer market power justification and began to argue that MOPRs maintain ideally competitive markets.

The history of MOPRs, in other words, is a story of administrative creep. Early MOPRs claimed to protect competitive electricity markets, and they did so by administratively pricing bids submitted by net buyers of capacity.[14] Today's MOPRs also claim to protect competitive electricity markets, and they do so by

9. *N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,211 at PP 103-106 (2008). S*ee also, e.g.*, *id*. at P 103:

> Markets require appropriate price signals to alert investors when increased entry is needed. By allowing net buyers to artificially depress prices, these necessary price signals may never be seen. While a strategy of investing in uneconomic entry and offering it into the capacity market at a low or zero price may seem to be good for customers in the short-run, it can inhibit new entry, and thereby raise price and harm reliability, in the long-run.

10. Net buyers are firms that both buy and sell electricity in wholesale markets, but that purchase more electricity than they sell. Net buyers have an incentive to offer to sell capacity at a loss because doing so can reduce the price they pay for capacity. To date, buyer-side market mitigation rules have only been used in capacity markets. However, as discussed in Part IV, *infra*, the type of market manipulation to which FERC has responded can also occur in energy markets. *See PJM Interconnection, L.L.C.*, 135 F.E.R.C. ¶ 61,022 at PP 75-76, 86, 88-90 (2011).

11. *PJM Interconnection, L.L.C.*, 117 F.E.R.C. ¶ 61,331 at PP 1, 105, 140-41 (2006) (approving PJM's MOPR); *Devon Power, L.L.C.*, 115 F.E.R.C. ¶ 61,340, at P 1 (2006) (approving ISO-NE's alternative price rule); *N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C.¶ 61,211, at P 1 (approving NYISO's net buyer mitigation rules).

12. *N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C ¶ 61,211, at PP 64-70 (discussing these changes that occurred in 2008 in NYISO).

13. Part I, *supra*, explains how states can, in certain limited circumstances, act as net buyers of capacity. *See also* Delia Patterson & Harvey Reiter, *Chasing the Uncatchable: Why Trying to Fix Mandatory Capacity Markets is Like Trying to Win a Game of Whack-a-Mole*, STINSON LLP 2 (June 2016), https://www.stinson.com/assets/htmldocuments/Chasing%20the%20Uncatchable.pdf.

14. *See* Joshua C. Macey & Jackson Salovaara, *Rate Regulation Redux*, 168 UNIV. PA. L. REV. 1181, 1189 n.39, 1244-45, 1249 (2020) (discussing that other elements of wholesale electricity markets contain elements of administrative pricing); William Boyd, *Ways of Price Marking and the Challenge of Market Governance in U.S. Energy Law*, 105 MINN. L. REV. 739, 799-801, 800 n.285 (2020); Joshua C. Macey, *Zombie Energy Laws*, 73 VANDERBILT L. REV. 1077, 1095-96, 1105, 1118-19 (2020).

administratively repricing a significant percentage of resources that participate in east coast electricity markets.

MOPRs have had the opposite of their intended effect. FERC created MOPRs to facilitate the development of precisely engineered markets that match physical power flows to system needs in a competitive procurement process. Yet modern MOPRs disincentivize innovation, force consumers to pay for capacity they do not need, reduce generators' incentive to compete for cheaper labor and more favorable financing, and freeze in a region's generation mix years in advance.[15]

Given the outrage prompted by recent MOPR reforms, it is worth considering when, if ever, generator bidding strategies pose a threat to restructured electricity markets.[16] Despite its increasingly aggressive use of MOPRs, FERC has never provided a plausible account of why certain resources should be mitigated. Granted, the Commission has asserted that both buyer market power and state subsidies undermine competitive markets and threaten resource adequacy, but it has not explained how this distortion occurs.[17] To evaluate the legitimacy of price mitigation rules, it is therefore important to develop an account of why and in what ways buyer market power and state subsidies do (or do not) distort competitive electricity markets.

15. We are not the first to critique recent MOPR reforms or to trace the history of buyer side market power mitigation rules. Others have argued that MOPRs raise costs and lead to unjust and unreasonable prices. To date, commentators have focused on the undesirable *effects* of MOPRs—that they are anticompetitive, raise costs, encourage excess capacity to remain in the market, and lead to rates that are both arbitrary and capricious as well as unjust and unreasonable. However, while we share these concerns, our focus in this Article is not on the problems MOPRs generate, but rather on whether MOPRs have any justification at all and when—if ever—MOPRs are resolving a market failure. *See infra* Parts III-IV; *see also* Morrison, *supra* note 2, at 9-11, 21-22, 27-43 (tracing much of the same MOPR history and arguing (correctly, in our view) that centralized capacity constructs and MOPRs are ill-equipped to meet resource adequacy goals); Patterson & Reiter, *supra* note 13, at 4 (arguing that MOPRs are anticompetitive); Harvey Reiter, Jonathan Schneider, & Abraham Silverman, *Restoring Consensus and Balance to FERC's Market Policies*, 1 E.B.A. BRIEF 16, 16 (Fall 2020), https://www.eba-net.org/assets/1/6/EBA_Brief_-_Volume_1_Issue_2.pdf (proposing that FERC focus on "two core fundamentals: (1) respect for competitive resource adequacy markets (as opposed to the chase for an elusive perfect market); and (2) respect for state demands for a greener grid"); Todd S. Aagaard & Andrew N. Kleit, *A Road Paved with Good Intentions?: FERC's Illegal War on State Electricity Subsidies*, 33 ELEC. J. 1, 3-4, 6-7 (2020) (arguing that MOPR reforms lead to unjust and unreasonable rates); Richard B. Miller, Neil H. Butterklee, & Margaret Comes, *"Buyer-Side" Mitigation in Organized Capacity Markets: Time for a Change?*, 33 ENERGY L.J. 449, 450 (2012) (arguing that "FERC should not intervene in capacity markets in order to establish what it believes to be a just and reasonable rate").

16. "Restructured electricity markets" are markets in which service is provided through open competition among electric utilities and their competitors. Throughout the nineteenth century, electricity needs were historically met by vertically integrated utilities that provided generation, transmission, and distribution services. *See* U.S. GOV'T ACCOUNTABILITY OFFICE, RESTRUCTURED ELECTRICITY MARKETS: THREE STATES' EXPERIENCES IN ADDING GENERATING CAPACITY 1, 5 (May 2002), https://www.gao.gov/products/gao-02-427.

17. Today, it seems that FERC is trying to promote an idealized vision of markets in which suppliers compete free of outside influence, though historically, FERC has been more accommodating of state resource goals. If this is indeed FERC's goal, it is a quixotic vision that fails on its own terms. Wholesale electricity markets are highly regulated constructs that provide a structural advantage to certain resources. For more details, see the work of Jacob Mays, who has written extensively on this issue. *See, e.g.*, Jacob Mays, David P. Morton & Richard P. O'Neill, *Asymmetric Risk and Fuel Neutrality in Capacity Markets*, 4 NATURE ENERGY 948, 948-54 (2019), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3330932; Jacob Mays, *Missing Incentives for Flexibility in Wholesale Electricity Markets*, 149 ENERGY POLICY 1, 2-4 (2021), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3623962.

That is the task this Article takes up. The history of price mitigation in east coast electricity markets presents an opportunity to study (a) when, if ever, price suppression distorts competitive electricity markets, (b) why buyer market power poses challenges for restructured electricity markets, and (c) how state and federal policies should (or should not) be permitted to interact with each other.

Price suppression, caused by vertically integrated utilities that possess market power, does distort competitive electricity markets, but it does so for one—and only one—reason: because it gives vertically integrated utilities the ability, in theory, to engage in predatory pricing.[18] The real concern is that the threat of future market manipulation could prevent independent power producers from entering the market because they know that net buyers will continue to suppress the market clearing price, such that their competitors cannot earn a profit from wholesale market revenues.[19] This is a classic market for lemons problem in which a market failure (here, buyer market power) drives high-quality suppliers to exit the market.[20] But whether, and to what extent, this type of behavior is occurring remains an open question, since FERC has never provided any evidence that net buyers are engaging in predatory pricing.[21]

State subsidies do not distort markets in the same way. When a generator receives a payment for providing a service that the state values, it is able to sell electricity and a capacity at a lower price. Assuming the subsidized resource is not a vertically integrated utility, it has no incentive to submit a bid that will not permit it to recover its costs because it does not stand to benefit from selling electricity or capacity at a loss.[22] Thus, unlike price suppression caused by predatory pricing strategies, state subsidies do not threaten to drive independent power producers out of wholesale electricity markets. They simply generate a price signal that affects suppliers' behavior. Wholesale markets can easily accommodate such policies.

Buyer-side market power mitigation rules should therefore be used rarely, if ever, and only to mitigate buyer market power. FERC should be cautious about

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18. While there is a rich literature on seller market power in wholesale electricity markets, less has been written on buyer market power. *See* David B. Spence, *Can Law Manage Competitive Energy Markets?*, 93 CORNELL L. REV. 765, 789-94 (2008); David B. Spence, *Naïve Energy Markets*, 92 NOTRE DAME L. REV. 973, 977 (2017); David B. Spence & Robert Prentice, *The Transformation of American Energy Markets and the Problem of Market Power*, 53 B.C.L. Rev. 131, 132-33 (2012) (arguing that the securities model is inappropriate for market power abuses in energy markets). *See also* William Boyd, *Public Utility and the Low-Carbon Future*, 61 U.C.L.A. L. REV. 1614, 1617-20 (2014).

19. *See infra* Part IV. *See also* Boyd, *supra* note 18, at 1667-69; Michael Milligan et al., *Marginal Cost Pricing in a World without Perfect Competition: Implications for Electricity Markets with High Shares of Low Marginal Cost Resources,* NAT'L RENEWABLE ENERGY LAB. OF THE U.S. DEP'T OF ENERGY: TECH. REPORT NREL/TP-6A20-69076, at v-vi (Dec. 2017), https://www.nrel.gov/docs/fy18osti/69076.pdf.

20. *See* George A. Akerlof, *The Market for "Lemons": Quality Uncertainty and the Market Mechanism*, 84 Q. J. ECONOMICS. 488, 488 (1970).

21. *See infra* Part II. *See also* Morrison, *supra* note 2, at 31-34.

22. This assumes that the subsidized resource is not a vertically integrated utility. A vertically integrated utility has an incentive to submit below-cost bids, but that has nothing to do with the state subsidy. The utility's incentive is to drive its competitors to exit the market so that it can use its monopoly over transmission and distribution to expand its market share in markets for electricity and capacity. *See* Macey & Salovaara, *supra* note 14, at 1240-41; U.S. FED. TRADE COMM'N, COMPETITION AND CONSUMER PROTECTION PERSPECTIVES ON ELECTRIC POWER REGULATORY REFORM (July 2000), https://www.ftc.gov/reports/competition-consumer-protection-perspectives-electric-power-regulatory-reform.

imposing a system of administrative pricing to mitigate what remains an entirely theoretical problem. And, given the many problems associated with MOPRs, net buyers that are exercising market power should be broken up and prohibited from entering into the types of contracts that facilitate market power abuses.[23] In addition, rather than determine by regulatory fiat which resources are able to participate in capacity markets, FERC should instead bring enforcement actions against electric suppliers that abuse their market power. A second-best solution would be to scale back MOPRs so that they apply only to firms that have both the incentive and ability to abuse their market power, as was the case in the mid-2000s.

This Article proceeds in five parts. Part II provides background on electricity markets. Part III traces the history of buyer-side market power mitigation rules in east coast electricity markets. It shows how rules that were originally intended to protect markets from buyer market power have evolved into a system of administrative pricing in markets that are designed to determine resource entry and exit. It also describes the narrow circumstances in which states are capable of manipulating capacity market prices. Part IV explains how price mitigation rules are generating unnecessary costs, leading to oversupply, and impeding state decarbonization efforts. Part V responds to FERC's arguments about why MOPRs do not in fact prevent all resources from selling electricity at their preferred prices. Part VI argues that buyer market power poses a distinct market for lemons problem, that preventing net buyers from abusing their market power is the only legitimate justification for price mitigation rules and explains how recent decisions to expand price mitigation rules exceed FERC's delegated authority.

II. A History of Price Mitigation Rules

FERC has always thought of price mitigation as a tool that can encourage the development of competitive electricity markets. However, when FERC, PJM, and ISO-NE first developed these rules in 2006, they argued that buyer market power—and only buyer market power—was what distorted wholesale markets, though neither the Commission nor the grid operators explained why buyer market power presented an existential threat to competitive electricity markets.[24] Today, however, the three east coast grid operators treat price suppression as inherently problematic—regardless of whether it was caused by market manipulation or by state subsidies. This Part first explains why price mitigation rules emerged and how they function. The next Part describes the history of price mitigation rules in PJM, NYISO, and ISO-NE.

A. Restructured Electricity Markets

In the United States, policymakers have traditionally treated the generation, transmission, and distribution of electricity as a natural monopoly. Regulators granted utilities exclusive franchises and instructed them to provide nondiscriminatory service at regulated rates. In the latter half of the twentieth century, state

23. Our concern is with large distribution utilities that are in a position to exercise market power, not with small government utilities or rural co-ops.

24. *PJM Interconnection, LLC*, 117 F.E.R.C. ¶ 61,331, at PP 3, 23 (2006); *Devon Power LLC*, 115 F.E.R.C. ¶ 61, 340, at PP 27, 45, 83, 121-123, 135-137, 145-147 (2006). *See also N.Y. Indep. Sys. Operator, Inc.*, 122 F.E.R.C. ¶ 61,211, at P 1 (NYISO followed suit in 2008).

and federal policymakers in much of the country engaged in a concerted effort to expose generators to market forces.[25]

By the mid-2000s, however, just as market participants were adjusting to a restructured electricity sector, regulators became concerned that competitive markets were not creating a strong enough price signal.[26] They worried that not enough new generation was being built to meet demand.[27] Regulators and grid operators felt that they needed to develop additional revenue sources to incentivize construction of new generation. PJM, NYISO, and ISO-NE created capacity markets to meet the expected revenue shortfall in their regions.[28]

Capacity markets compensate generators for being available to provide electricity.[29] This contrasts with energy markets, which compensate generators for selling electricity.[30] In energy markets, grid operators determine how much electricity is needed to meet demand, and they dispatch the generators that are able to meet that demand at least cost.[31] If, for example, four generators each offer to sell 100 MWh of electricity and only 300 MWh are needed to meet demand, the grid operator will dispatch the three generators that submit the lowest bids. Each generator is paid the price offered by the highest bidder to clear. Thus, if one generator offers to sell 100 MWh for $200, another for $400, another for $1,000, and another for $2,000, and only three generators are needed to meet demand in that period, then the first three generators will clear the market. The three generators that clear the energy auction will each receive $1,000 for selling 100 MWh of electricity.[32] The generator that offered to sell 100 MWh of electricity for $2,000 will not be paid and will not provide electricity in that time period.

25. These changes can be traced to a rich scholarly debate critiquing rate regulation. *See* Harvey Averch & Leland L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, 52 AM. ECON. REV. 1052, 1052 (1962); William J. Baumol & Alvin K. Klevorick, *Input Choices and Rate-of-Return Regulation: An Overview of the Discussion*, 1 BELL J. ECON. & MGMT. SCI. 162, 163 (1970); Alvin K. Klevorick, *The Behavior of a Firm Subject to Stochastic Regulatory Review*, 4 BELL J. ECON. MGMT. SCI. 57, 60-68 (1973); Paul L. Joskow, *The Determination of the Allowed Rate of Return in a Formal Regulatory Hearing*, 3 BELL J. ECON. & MGMT. SCI. 632, 633-34 (1972) (describing the challenges public utilities commissioners face in determining a proper rate of return in light of informational asymmetries). For an excellent history of restructuring, *see also* Harvey L. Reiter, *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation Under the Federal Power and Natural Gas Acts*, 18 LAND & WATER L. REV. 1, 1-3 (1983); Macey & Salovaara, *supra* note 14, at 1194-1203.

26. Peter Cramton & Steven Stoft, *The Convergence of Market Designs for Adequate Generating Capacity with Special Attention to the CAISO's Resource Adequacy Problem*, WHITE PAPER FOR THE ELEC. OVERSIGHT BD. 43-46, 60-61 (Apr. 25, 2006), http://www.cramton.umd.edu/papers2005-2009/cramton-stoft-market-design-for-resource-adequacy.pdf.

27. *Id*. at 31-39.

28. 117 F.E.R.C. ¶ 61,331 at PP 12, 14-19; 115 F.E.R.C. ¶ 61,340, at PP 1-2.

29. Sylwia Bialek & Burcin Unel, *Capacity Markets and Externalities: Avoiding Unnecessary and Problematic Reforms*, INST. FOR POLICY INTEGRITY N.Y. UNIV. SCH. L.: ELEC. POLICY INSIGHTS, at 4 (Apr. 2018), https://policyintegrity.org/files/publications/Capacity_Markets_and_Externalities_Report.pdf.

30. *Id*. at 3-4.

31. *Id*.

32. Bialek & Unel, *supra* note 29, at 4-6; *see also* INDEP. SYS. OPERATOR N.E., DAY-AHEAD AND REAL-TIME ENERGY MARKETS (2021), https://www.iso-ne.com/markets-operations/markets/da-rt-energy-markets/ (noting that, in reality, there are day-ahead markets and real-time energy markets (markets that allow resources to buy and sell electricity in real time), where most resources submit bids a day in advance).

Generators in energy markets typically will bid their marginal costs of production.[33] If a generator offers to sell electricity for less than its marginal costs, it risks being dispatched when the costs of generating electricity exceed the revenue it receives from the energy market.[34] If it offers to provide electricity for more than its marginal costs, it risks not being dispatched at times when the clearing price is high enough for the generator to make a profit selling electricity.[35]

In theory, energy markets can create an adequate incentive for new generators to enter the market when they are needed.[36] Although most generators have an incentive to bid their marginal costs, that does not apply to peaking plants (also known as "peakers"), which operate when demand is high.[37] These plants generally have high operating costs and operate only a few hours a day. In some cases, they operate only a few times a year.[38] Since peakers provide electricity when supply is scarce, they can submit above-marginal-cost bids.[39] Peakers are not concerned that they will be displaced by power plants with more expensive operating costs, because there are few, if any, other generators in the market that could displace them.[40] They can therefore set the market clearing price, which creates an incentive to submit very high bids.[41] The revenue generated in those periods is theoretically sufficient to induce market entry.

However, peakers can also exercise market power. The ability to drive energy prices to very high levels can—and has—led market participants to devise strategies to manipulate energy market prices.[42] To prevent peakers from manipulating energy markets, every grid operator in the United States has implemented offer caps to limit the price at which generators can offer to sell electricity in energy markets.[43] In that way, offer caps limit the ability of peakers to raise prices during scarcity conditions and thus disincentivize manipulative behavior.

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33. Marginal costs are the costs a firm incurs for producing one additional unit of a product or service. In electricity, those costs consist primarily of operating costs and fuel costs. OFFICE OF ELEC. DELIVERY & ENERGY RELIABILITY, U.S. DEP'T OF ENERGY, *United States Electricity Industry Primer*, (July 2015), https://www.energy.gov/sites/prod/files/2015/12/f28/united-states-electricity-industry-primer.pdf.

34. Milligan et al., *supra* note 19, at 23-25..

35. Bialek & Unel, *supra* note 29, at 4 n.11.

36. Paul L. Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design*, 16 UTIL. POLICY 159, 159-60, 159 n.1 (2008); William W. Hogan, *On an "Energy Only" Electricity Market Design for Resource Adequacy*, SCHOLARS OF HARVARD (Sept. 23, 2005) (unpublished manuscript), https://scholar.harvard.edu/whogan/files/hogan_energy_only_092305.pdf.

37. Bethel Afework et al., *Peaking Power*, ENERGY EDUC. ENCYCLOPEDIA (Sept. 2018), https://energyeducation.ca/encyclopedia/Peaking_power; Hogan, *supra* note 41, at 2-6.

38. Bialek & Unel, *supra* note 29, at 4-5.

39. Milligan, *supra* note 19, at 24-25.

40. Peter Cramton, *Electricity Market Design*, 33 OXFORD REV. ECON. POL'Y 589, 597 (2017).

41. *Id*.

42. *See* Richard A. Oppel Jr. & Jeff Gerth, *Enron Forced Up California Prices, Documents Show*, N.Y. TIMES (May 7, 2002) ("Electricity traders at Enron drove up prices during the California power crisis through questionable techniques that company lawyers said 'may have contributed' to severe power shortages.").

43. *See, e.g.*, PJM, ENERGY OFFER VERIFICATION FAQ, https://www.pjm.com/-/media/markets-ops/energy/energy-offer-verification/offer-verification-faqs.ashx?la=en (describing PJM's process for complying with FERC Order 831's offer cap requirements); 16 TEX. ADMIN. CODE § 25.505(g)(6) (setting ERCOT's system-wide offer cap at $9,000/MWh).

But offer caps introduce inefficiencies of their own. In limiting the amount of money that generators can earn in energy markets, offer caps can prevent generators from recovering their fixed and capital costs and deter prospective generators from building new power plants.[44] Offer caps can therefore prevent generators that are needed to meet demand from entering the market.[45] This is known as the "missing money problem."[46]

In the early 2000s, PJM, ISO-NE, and NYISO had all implemented offer caps.[47] At the same time, they all feared that not enough capacity was expected to enter the market to meet future demand.[48] FERC and the east coast grid operators developed capacity markets to provide additional revenue that was needed to encourage the construction of new generation.[49] By compensating generators for being available to provide electricity, capacity markets provide revenue to generators that can commit to supplying electricity—regardless of whether the generator clears the market and actually sells electricity.[50] In that way, capacity markets ensure that there is enough supply to meet a region's demand for electricity.[51]

In a capacity market, a grid operator determines how much capacity is needed to meet peak demand over a period of time and selects the lowest-cost bidders that are able to meet that demand.[52] As in energy markets, each generator that clears a capacity auction receives the same compensation for the capacity it provides.[53] For example, if a region needs 300 MW of power, and if four 100 MW generators each offer to sell their capacity to the region, then the three least expensive bids will clear the capacity auction and the fourth will not.[54] Thus, if one generator

44. David Newbery, *Missing Money and Missing Markets: Reliability, Capacity Auctions and Interconnectors 3,* ENERGY POL'Y RESEARCH GRP., (Working Paper No. 1508) (2015), https://www.eprg.group.cam.ac.uk/wp-content/uploads/2015/03/1508_updated-July-20151.pdf.

45. *Id.*

46. James Bushnell, Michaela Flagg & Erin Mansur, *Capacity Markets at a Crossroads*, (Working Paper No. 278) (2017), https://hepg.hks.harvard.edu/files/hepg/files/wp278updated.pdf.

47. Final Rulemaking, *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, 81 Fed. Reg. 87,770 (2016) (codified at 18 C.F.R. pt. 35) (describing offer caps in all six RTOs/ISOs).

48. 117 F.E.R.C. ¶ 61,331, at PP 3-4 (describing conditions that led to development of PJM's Reliability Pricing Model, including that "the addition of new generating units to the system will lag dramatically behind the anticipated growth in demand").

49. *See* 117 F.E.R.C. ¶ 61,331, at PP 1-3; 115 F.E.R.C. ¶ 61,340, at PP 1-15; *New York Independent System Operator, Inc.*, 103 F.E.R.C. ¶ 61,201 at PP 1–10 (2003).

50. Bushnell, *supra* note 46, at 28.

51. Other areas of the country do not use capacity markets. *See, e.g.* ERCOT, RESOURCE ADEQUACY, http://www.ercot.com/gridinfo/resource#:~:text=RA%20in%20Texas-Resource%20Adequacy,grid%20reliability%20if%20shortfalls%20occur (last visited Mar. 3, 2021).

52. PJM, UNDERSTANDING THE DIFFERENCE BETWEEN PJM'S MARKETS, (Mar. 6, 2019) https://learn.pjm.com/-/media/about-pjm/newsroom/fact-sheets/understanding-the-difference-between-pjms-markets-fact-sheet.ashx.

53. *See* PJM MANUAL 18: PJM CAPACITY MARKET (May 28, 2020), https://www.pjm.com/~/media/documents/manuals/m18.ashx.

54. In reality, capacity markets are more complicated than the examples above. They generally compensate generators for providing an amount of capacity per day while also "derating" capacity such that a generator's capacity payment reflects the frequency with which it is available to meet peak demand. *See*, *e.g.* PJM RELIABILITY PRICING MODEL RESULTS, https://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-base-residual-auction-report.ashx (PJM BRA Results); ISO-NE FORWARD CAPACITY AUCTION RESULTS, https://www.iso-ne.com/static-assets/documents/2018/05/fca-results-report.pdf

offers to sell 100 MW of capacity for $100, another for $1,000, another for $10,000, and another for $20,000, then the first three generators clear the auction. Each is paid $10,000. The fourth generator does not clear and need not participate in the region's energy market during the capacity commitment period. As in energy markets, generators typically will not have an incentive to submit below-cost capacity bids. If a generator submits a below-cost bid, it risks being forced to operate even if it would lose money doing so. An above-cost bid risks not clearing an auction even when it would be profitable for the generator to operate.

B. The Origins of Buyer-Side Market Power Mitigation Rules

But capacity markets, like energy markets, are vulnerable to market power abuses. Load Serving Entities (LSEs), which purchase electricity from generators and transport it to consumers,[55] have an incentive to submit artificially low capacity bids. Generators that are owned by LSEs can offset the losses their generators incur *selling* capacity in the form of lower prices their distribution assets *pay* for capacity.[56] A below-cost bid will displace a more expensive offer that would have been needed to meet the region's capacity needs.[57] Since the higher-cost bid no longer clears the capacity auction, it no longer sets the clearing price. That, in turn, drives the capacity price down. Since all generators that clear capacity auctions are paid the same price for capacity, below-cost bids that are at the margin reduce the revenue all generators receive from capacity markets and, in that way, reduce the price that the LSE is required to pay for capacity. Preventing this type of market manipulation was the sole purpose of buyer-side market power mitigation rules in the mid-2000s.[58]

Unlike independent power producers, LSEs have both the incentive and the ability to submit below-cost capacity bids. Imagine if, in the example above, a fifth 100 MW generator enters the market and is owned by the LSE that is required to purchase capacity from the capacity auction. Imagine, too, that this generator needs $15,000 from the capacity market to cover its costs. If it bids $15,000, it will not clear the market because the $100, $1,000, and $10,000 generators will provide all the capacity that the region needs. If, however, the generator offers to provide capacity for $0, it will clear the market. The generator will incur a $15,000 loss, but the generator's $0 bid will save the LSE $27,000. That is because the generator's $0 bid means that the $10,000 generator is no longer needed. The LSE's generator, the $100 generator, and the $1,000 generator can provide all the capacity the region needs. As a result, the LSE's decision to submit a below-cost bid means that the $1,000 generator—not the $10,000 generator—will set the

(ISO-NE FCA Results); NYISO INSTALLED CAPACITY AUCTIONS RESULTS, http://icap.nyiso.com/ucap/public/auc_view_monthly_detail.do (NYISO).

55. New Jersey Bd. Pub. Util. v. FERC, 744 F.3d 74, 82 (3d Cir. 2014).

56. *Id.* at 101. *See also* 117 F.E.R.C. ¶ 61,331, at P 104 (stating that PJM's MOPR is a "reasonable method of assuring that net buyers do not exercise monopsony power by seeking to lower prices through self-supply"); 115 F.E.R.C. ¶ 61,340, at P 113 (finding that ISO-NE's APR will address incentives that new self-supplied capacity may have to depress the auction price).

57. This is only the case if the generator that submitted a below-cost bid would not have cleared the capacity auction if it had submitted a bid that reflected its actual costs.

58. *See Devon Power LLC*, 115 F.E.R.C. ¶ 61,340; *see also PJM Interconnection LLC*, 117 F.E.R.C. ¶ 61,331.

clearing price. Without its artificially low bid, the LSE would have paid $30,000 for capacity. The LSE's below-cost bid means it has to pay only $3,000. The $27,000 it saves by suppressing the price it pays for capacity offsets the $14,000 its generator incurs by selling capacity at a loss. Note, though, that the LSE's bid also means that every other generator that clears the capacity auction receives $1,000 instead of $10,000. As a result, the LSE's price-suppressive bid will reduce the incentive for new generators to enter the market.[59]

Still, when FERC and grid operators developed price mitigation rules in 2006, they seem to have done so to prevent net buyers from engaging in this type of behavior. For example, in the Order approving ISO-NE's capacity market, FERC expressed concern that net buyers would "artificially suppress the auction's clearing price below the price needed to elicit new entry when new entry is needed."[60] Similarly, in approving the New York City capacity market,[61] FERC noted that a net buyer could "reduce the market price for capacity and lower the net buyer's total capacity bill."[62] The Commission further explained that, "[i]f the newly added capacity represents only a portion of the net buyer's total capacity needs, the reduction in the buyer's total capacity bill caused by the lower prices could more than offset the loss on the newly added capacity investment."[63]

FERC also suggested that buyer market power could create resource adequacy problems. Despite the fact that buyer market power will never lead to a revenue shortfall,[64] FERC worried that such "artificially depressed prices"[65] would hinder the ability of the capacity market to send "appropriate price signals to alert investors when increased entry is needed"[66] and deny market participants a "reasonable opportunity to recover the costs of needed investment."[67]

FERC has never provided proof that net buyers are engaging in this type of predation. It is therefore an open question if net buyers are manipulating capacity market prices, or if this problem is purely theoretical. Still, despite being undertheorized, the Commission's primary concern was initially that net buyers would manipulate capacity markets in order to reduce their own costs and, in that way,

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59. When he was a judge on the First Circuit, Justice Breyer expressed concern that aggressive prohibitions on predatory pricing would create more problems than they would solve. *See* Barry Wright Corp. v. ITT Grinnell Corp., 724 F.2d 227, 234 (1st Cir. 1983) ("The antitrust laws very rarely reject such beneficial 'birds in hand' [an immediate price cut] for the sake of more speculative 'birds in the bush'" [preventing exit and thus preventing increases in price in the future].). Justice Breyer has found support among some prominent antitrust scholars. *See, e.g.* Einer Elhauge, *Why Above-Cost Price Cuts To Drive Out Entrants Are Not Predatory - and the Implications for Defining Costs and Market Power*, 112 YALE L.J. 681 (2003). However, Aaron Edlin has offered a powerful critique of this view, showing that "there is no bird in hand because entry cannot be presumed." *See* Aaron Edlin, *A New Theory of Predatory Pricing, in* RESEARCH HANDBOOK ON THE ECONOMICS OF ANTITRUST LAW, (Einer Elhauge ed., 2012). Edlin asks why an "entrant [that] anticipates being outcompeted or predated post entry would ever . . . enter." *Id.* at 8. Based on that observation, he concludes that the "'bird in hand' view presumes entry, and thus is just as speculative a proposition as the fear of high prices post exit." *Id.*

60. 115 F.E.R.C. ¶ 61,340, at P 115.

61. 122 F.E.R.C. ¶ 61,211, at P 101.

62. *Id.*

63. *Id.*

64. *See infra* Part IV.

65. 122 F.E.R.C. ¶ 61,211, at P 103.

66. *Id.*

67. *Id.* at P 105.

prevent the capacity market from providing sufficient revenue to induce the requisite level of market entry.[68]

III. The History of Buyer-Side Market Power Mitigation Rules

Although the specifics of buyer-side market power mitigation rules vary by region,[69] they generally set a floor below which resources subject to mitigation cannot offer to sell capacity. For example, if, in the example above, the LSE's generator had been subjected to a $15,000 price floor, it would have been unable to submit a below-cost bid that suppressed the price of capacity. In that way, price floors prevent net buyers from submitting below-cost bids.[70]

Though similar in many respects, the three eastern RTOs that have adopted buyer-side market power mitigation rules have relied on slightly different approaches since they first began mitigating capacity market bids in the mid-2000s. Despite these differences, all three initially focused on buyer market power, and all three have since begun to focus on promoting ideally competitive markets by mitigating offers from any resource that receives out-of-market support. This Part traces the history of buyer-side market power mitigation rules in PJM, NYISO, and ISO-NE.

A. History of Price Mitigation in PJM

PJM adopted a minimum offer price rule (MOPR) in 2006 to curb buyer market power abuses. Then, in 2011, FERC expanded PJM's MOPR to include resources that receive state subsidies. At the time, the Commission continued to defend price mitigation on the ground that it would curb market power abuses. By 2017, FERC had abandoned the market power justification altogether and began arguing that price suppression is inherently problematic. The Commission did not, however, explain how price suppression distorts the PJM capacity market.

1. The Origins of Price Mitigation in PJM

PJM implemented its MOPR in 2006 when it first created a capacity market. Specifically, PJM adopted a Reliability Pricing Model, which is PJM's name for

68. 115 F.E.R.C. ¶ 61,340 at PP 28, 71, 113 (approving settlement agreement establishing the Forward Capacity Market (FCM) with an Alternative Price Rule (APR) to address market power held by buyers); 122 F.E.R.C ¶ 61,211 at P 100 (accepting, subject to conditions, NYISO proposal for buyer-side mitigation in order to prevent uneconomic entry that would reduce prices in the New York City capacity market below just and reasonable levels); 117 F.E.R.C. ¶ 61,331, at PP 7, 104 (approving settlement concerning PJM's Reliability Pricing Model (RPM) and Minimum Offer Price Rule (MOPR) as a reasonable method of assuring that net buyers do not exercise monopsony power); *PJM Interconnection, L.L.C.*, 128 F.E.R.C.¶ 61,157, at P 91 (2009) ("The lower prices that would result under MPC's proposal would undermine the market's ability to attract needed investment over time. Although capacity prices might be lower in the short run, in the long run, such a strategy will not attract sufficient private investment to maintain reliability. The MOPR is the mechanism that restricts the ability of an LSE from using its position as dominant buyer in the market to suppress market clearing prices for at-risk investors, and is analogous to the way market power mitigation rules restrict dominant at-risk investors from using their market position to raise market clearing prices by creating an artificial scarcity. The MOPR does not punish load, but maintains a role for private investment so that investment risk will not be shifted to captive customers over time.").

69. Note that ISO-NE did initially adopted a clearing price reset mechanism, not a price floor. *See infra* Part I.B.

70. *PJM Interconnection, LLC*, 117 F.E.R.C. ¶ 61,331, at P 103.

its capacity market, because it felt that the region's energy markets had failed to provide sufficient revenue to induce market entry. PJM's MOPR was designed to prevent LSEs from abusing their market power. PJM's MOPR set a minimum bid amount below which resources subject to mitigation could not offer to sell capacity. For example, if a resource was willing to sell 100 MW of capacity for $10,000, and if the price floor prohibited resources of that type from offering to sell 100 MW of capacity for less than $15,000, then the resource would have been required to bid $15,000 despite its willingness to bid $10,000. If the capacity market ended up clearing at a price that compensated 100 MW generators $12,000, then the resource would not clear the market. It would, however, have cleared had it been allowed to bid $10,000.

The 2006 MOPR applied only to net buyers that had both the incentive and ability to suppress capacity prices.[71] Specifically, the price floor did not apply when (1) the offer actually affected the market clearing price (the impact screen),[72] (2) the seller had a "net short position" (the net buyer screen),[73] and (3) the offer was below the bid floor (the conduct screen).[74] These three screens ensured that PJM only mitigated bids that actually reduced the capacity price, were below the expected costs of constructing a power plant, and were submitted by a bidder that was in a position to benefit from selling capacity at a loss.

The impact screen ensured that the PJM MOPR applied only to bids that could affect capacity prices.[75] Specifically, if a bid did not suppress the capacity market price by (a) $25 dollars per MW per day, or (b) more than twenty percent, it was not subject to the PJM price floor. Thus, a below-cost bid that did not in fact benefit the bidder by meaningfully reducing the price it paid for capacity was not mitigated. Such bids harm below-cost bidders but do not affect other market participants. A bid that does not actually affect the clearing price does not reduce the price that LSEs pay for capacity and therefore does not affect other market participants. In such circumstances, an LSE's affiliated generator incurs a loss from selling below-cost capacity but, because the bid does not affect the capacity price, the LSE would not be able to offset the generator's loss by reducing the amount it pays to purchase capacity. And, because the LSE's bid does not suppress the market clearing price, the other generators that clear the capacity auction receive the same revenue that they would have received if the LSE's affiliated generator had not participated in the auction.

The second two conditions served a similar purpose. For example, the net buyer screen exempted from mitigation companies that did not have a financial incentive to suppress capacity prices.[76] Companies that sell more capacity than they purchase rely on electricity markets to make a profit. They therefore have no incentive to suppress capacity prices to a level that would cause them to incur a

71. *PJM Interconnection, LLC*, 119 F.E.R.C. ¶ 61,318, at PP 165-72 (2007).

72. *Id.* at P 166.

73. *Id.* Specifically, the net short position had to be equal or greater than five or ten percent of the Locational Deliverability Area's reliability requirement.

74. *Id.*

75. *Id.* at PP 167.

76. *See* 117 F.E.R.C. ¶ 61,331 at PP 103-04; 135 F.E.R.C. ¶ 61,022 at P 75.

loss. For that reason, FERC and PJM felt, in 2006, at least, that they could trust net sellers to determine for themselves their profit-maximizing bid strategy.

The third condition, which exempted from mitigation bids that were above the price floor, allowed net buyers to sell capacity when the grid operator determined that the bid reflected the market price of capacity. Specifically, since 2006, price floors in PJM have been based on a resource's Cost of New Entry (CONE), which represents an administrative assessment of the revenue that a power plant needs in order to recover its capital investment and fixed costs.[77] To calculate the offer floor, PJM determines the *net* Cost of New Entry (net CONE), which represents the revenue that a generator needs to receive from the capacity market in order to cover its capital investment and fixed costs.[78] Net CONE is calculated by first determining the CONE for that type of resource and then subtracting the revenue that the resource can expect to make from the energy and ancillary services markets.[79] For example, if PJM determines that a certain type of resource needs $1,000,000 a year in order to recover its fixed and capital costs, its CONE will be $1,000,000. If it can expect to recover $700,000 from energy and ancillary services markets, its net CONE will be $300,000.[80]

Notably, both CONE and net CONE are calculated based on asset class—not based on the individual generator's actual costs. Thus, when a combined cycle gas plant is subject to an offer floor, PJM calculates the revenue that it expects is necessary to construct a combined cycle gas plant.[81] If a specific resource's price floor is higher than the price needed to clear a capacity auction, then the resource will not clear—even if, for whatever reason, the resource had been willing to sell capacity for a lower price.

Finally, PJM's 2006 MOPR included two additional qualifications that exempted resources from mitigation. First, the seller was given an opportunity to demonstrate that its offer was cost-justified.[82] PJM described this process as the

77. *See* THE BRATTLE GRP., PJM COST OF NEW ENTRY: COMBUSTION TURBINES AND COMBINED-CYCLE PLANTS WITH JUNE 1, 2022 ONLINE DATE 21 (2018) https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

78. PJM and NYISO adopted slightly different price floors. In PJM, the net CONE was 80% of the applicable net asset class CONE. 119 F.E.R.C. ¶ 61,318, at P 166. NYISO, by contrast, gave resources slightly more discretion by setting the floor at 75% CONE. 122 F.E.R.C. ¶ 61,211, at P 107.

79. 117 F.E.R.C. ¶ 61,331, at P 26.

80. These examples are illustrative. The Net CONE value for the 2022/2023 BRA in PJM was $110,459/ICAP MW-year or $321.57 UCAP/MW-day based on a Gross CONE of $135,309/ICAP MW-year and net energy and ancillary services of $24,851/ICAP MW-year, reflecting the dispatch of a new General Electric Frame 7HA turbine, plus a 10% cost adder. PJM, *2022/2023 RPM Base Residual Auction Planning Period Parameters*, http://www.pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2022-2023/2022-2023-planning-period-parameters-for-base-residual-auction-pdf.ashx (last visited Mar. 26, 2020).

81. PJM's recent compliance filing provided illustrative average CONE and net CONE estimates for several planned resource types. PJM estimates gross CONE for planned nuclear at $2,000/MW-day, while net CONE is estimated at $1,483/ICAP MW-day. For a planned combined cycle resource, PJM estimated an average Gross CONE of $320/MW-day and net CONE of $152/ICA MW-day. For intermittent resources, PJM adjusts net CONE values to reflect average output levels. As a result, PJM estimated a gross CONE for planned offshore wind of $1,155/MW-day and net CONE of $3,146/ICAP MW-day, based on an expected average output level of 26.0%. *PJM Compliance Filing*, 64-65 (Docket Nos. EL16-49, ER18-1414, EL18-178) (Mar. 18, 2020).

82. In fact, even when the seller was subjected to an offer floor, PJM would conduct a sensitivity analysis to determine if the offer should be increased to a specified alternative default level, with the adjustment taking effect only if the sensitivity analysis showed specific effects on market clearing prices. *See id.* at 171.

unit-specific resource exemption, though the grid operator has since changed the name to resource-specific resource exemption. The unit-specific exemption allows a resource to demonstrate that its bid reflects its actual costs, in which case it is permitted, at least in theory, to submit a bid that reflects those costs.[83] Second, resources that received state subsidies were also exempted from mitigation.[84] The FPA reserves to the states authority to control their own generation assets.[85] PJM initially refrained from mitigating bids submitted by resources that enjoyed state support in order to accommodate state policy preferences.[86]

In sum, price mitigation in PJM emerged to mitigate market power abuses by net buyers of capacity. Not only did PJM list buyer market power as the singular goal of its 2006 price mitigation rule, but it also included a number of screens that limited mitigation to entities that had both the incentive and ability to manipulate the price of capacity.

2. A Broader View of Market Power Abuses

PJM expanded its MOPR in 2011, and it did so across two dimensions. First, PJM expanded the scope of mitigation by eliminating the impact screen and the net short requirement, and by extending the MOPR to resources that received state support.[87] Second, PJM made MOPRs more restrictive by revising the conduct screen such that it applied to bids below ninety percent net CONE instead of eighty percent net CONE.[88]

a. Eliminating PJM's Net Short Requirement

In 2011, PJM began to worry about the feasibility of developing a definition of the net short requirement.[89] PJM and FERC felt that the process of developing a precise definition of "net buyer" was like playing "whack-a-mole."[90] The specific problem, according to the Commission, was that "the net-short requirement

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83. As Part III shows, it does not appear that the unit-specific exemption has allowed resources to avoid a system of administrative pricing.

84. 2006 RPM Settlement Order, 117 F.E.R.C. ¶ 61,331, at P 104.

85. 16 U.S.C. § 824(b)(1); Matthew Christiansen & Joshua C. Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1363 (2021); Jim Rossi, *The Brave New Path of Energy Federalism*, 95 TEX. L. REV. 399, 413 (2017); William Boyd & Ann E. Carlson, *Accidents of Federalism: Ratemaking and Policy Innovation in Public Utility Law*, 63 UCLA L. REV. 810, 813 (2016); Jim Rossi & Thomas Hutton, *Federal Preemption and Clean Energy Floors*, 91 N. CAR. L. REV. 1283, 1286 (2013).

86. 2006 RPM Settlement Order, 117 F.E.R.C. ¶ 61,331, at P 104.

87. 135 F.E.R.C. ¶ 61,022, at P 101.

88. *Id.* at PP 3, 86 (accepting PJM's proposal to eliminate the net short requirement and the net impact screen); aff'd 137 F.E.R.C. ¶ 61,145, at P 61 (2011) (denying rehearing requests). PJM also increased net CONE from eighty to ninety percent. *Id.* at P 66. ("[W]e accept PJM's proposal to raise the conduct screen to 90 percent of Net CONE, from the current 80 percent threshold, as a reasonable level. This level reasonably balances the need to prevent uneconomic entry, the inherent vagaries of cost estimation, and the administrative burdens entailed by having to provide data to justify a generator-specific lower threshold.").

89. 135 F.E.R.C. ¶ 61,022 at PP 1, 2, 75–79.

90. Delia Patterson and Harvey Reiter first used the phrase "whack-a-mole" to describe FERC's attempts to use MOPRs to fix centralized capacity markets. *See*, Delia Patterson & Harvey Reiter, *FERC Chasing the Uncatchable: Trying To Fix Mandatory Capacity Markets Like Trying To Win Whack-a-Mole*, PUB. UTIL. FORTNIGHTLY (May 2016), https://www.fortnightly.com/fortnightly/2016/05/ferc-chasing-uncatchable.

can be gamed, and the evasion can come in a variety of forms."[91] FERC provided two examples to illustrate how net buyers could suppress capacity prices without triggering the MOPR. First, FERC pointed out that net buyers could rely on bilateral contracts to exercise market power.[92] Second, FERC was concerned that state subsidies could manipulate capacity markets in a similar manner.[93]

Though FERC did not fully explain how LSEs could use bilateral contracts to abuse their market power, the Commission was correct that, in limited circumstances, net buyers can use bilateral contracts, particularly contracts for differences, to drive down the cost of capacity. In a contract for differences, a buyer and seller agree that the seller will participate in a market, but the parties agree to pay the difference between the settlement price and the market clearing price. For example, an LSE and a generator might agree that the generator will participate in a capacity market but will receive \$100,000 a year to provide 100 MW of capacity regardless of the market clearing price.[94] If the capacity market pays 100 MW generators \$80,000, then the buyer will make up the difference and pay the generator \$20,000. But if the capacity market pays 100 MW generators \$120,000, then the generator will remit \$20,000 to the buyer. This contract allows each party to hedge against capacity market volatility by stabilizing the price at \$100,000.

However, contracts for differences can be used to manipulate the price of capacity. These contracts give the seller an incentive to offer to sell capacity for \$0. A \$0 bid will ensure that the seller clears the capacity market and therefore guarantees that, in the example above, the seller will receive \$100,000 for selling capacity. FERC seems to have been concerned that LSEs would enter into contracts for differences not to hedge against price volatility, but rather to lower the price they pay for capacity. Even if the contract guarantees the seller an above-market rate, the LSE might be willing to pay this premium to reduce the price of capacity. Because the seller will receive \$100,000 regardless of the market clearing price, it will bid \$0 to ensure that it clears.

At the same time, the buyer might be willing to enter into the contract—even if it is overpaying for capacity—because, in doing so, it can drive down the price of capacity by ensuring that its counterparty offers to sell capacity for \$0. Because the buyer and seller are not affiliated with each other, PJM's 2006 MOPR would have exempted the bid from mitigation. Hence FERC's concern that "the net-short requirement's narrow focus may enable a net buyer, or an entity acting on behalf of a net buyer, to evade mitigation by structuring a new entry transaction in such a way that achieves the same price-lowering effect without triggering the MOPR."[95] In the paper hearing that led up to FERC's 2011 PJM MOPR Order, the Commission received a number of comments explaining that LSEs could use bilateral contracts to manipulate capacity prices.[96] The challenge for a regulator

91. 135 F.E.R.C. ¶ 61,022, at P 88.

92. *Id.* at P 204.

93. *Id.* at P 187.

94. *See*, *e.g.*, N.J. Bd. Pub. Util. Final Proposed Form Standard Offer Capacity Agreement § 4 (Mar. 1, 2011), https://www.nj.gov/bpu/pdf/energy/FinalProposedFormSOCA.pdf.

95. *PJM Interconnection, LLC*, 119 F.E.R.C. ¶ 61,318, at PP 87–88.

96. For example, PJM pointed out "that a buyer wishing to reduce the clearing price below a competitive level for the benefit of its load could achieve that result through the terms of its power purchase agreement with the new entrant, even though the buyer is neither the seller nor an affiliate of the seller." *Id.* at P 87. According

is therefore to distinguish between legitimate price hedges and illegitimate attempts to manipulate the price of capacity.

FERC also worried that state subsidies could be used to manipulate capacity markets. The Commission explained that "the net-short requirement allows a state-supported seller that does not itself serve load to make an uncompetitively low offer that will not trigger the MOPR, as the seller would not be in a 'net-short' position."[97] It is not immediately clear from FERC's statement how state subsidies generate the same problems as market manipulation by net buyers.[98] By definition, state subsidies provide a separate source of revenue that allows subsidized resources to submit lower capacity market bids. State subsidies reduce the price all resources pay for capacity. When new entry is needed, the price of capacity will increase, which will prompt new suppliers to enter the market.[99] As Part V explains, that type of price suppression is valuable, even absent environmental goals, because it means that the price of capacity declines.

The most generous interpretation of the Commission's decision to eliminate PJM's net buyer requirement is that FERC believed that doing so was necessary to prevent LSEs and states from manipulating capacity market prices, though, as Part V explains, unlike net buyers that wield market power, states have neither the incentive nor the ability to use contracts for differences to manipulate wholesale prices. That is perhaps the best explanation of the Commission's cryptic assertion that "the net-short requirement allows a state-supported seller that does not itself serve load to make an uncompetitively low offer that will not trigger the MOPR, as the seller would not be in a 'net-short' position."[100]

It thus appears that, by 2011, FERC believed that states had an incentive to manipulate capacity market prices, even though states by definition cannot take a

to the grid operator, "[s]uch a buyer could simply commit to cover the seller's costs and direct in the contract that the seller offer the new plant's capacity at a low price, and such a transaction would not trigger the current MOPR." *Id.*

97. *Id.*

98. Part III explains how a contract-for-difference, the contract used in these transactions, actually does generate unique problems and can be understood as an attempt by states to manipulate capacity markets. But the Commission did not explain this reasoning in this Order.

99. *See* INST. FOR POLITICAL INTEGRITY AT N.Y. UNIV. SCHOOL OF LAW, *Comments on PJM MOPR Filing*, (Oct. 2, 2018), https://policyintegrity.org/documents/Policy_Integrity_Comments_EL18-178.pdf.

100. In fact, FERC received a number of comments that likened state contracts for differences to market manipulation by net buyers of capacity. For example, the Pennsylvania Commission submitted comments arguing "that [PJM's] net-short requirement allows a state-supported seller that does not itself serve load to make an uncompetitively low offer that will not trigger the MOPR, as the seller would not be in a 'net-short' position." 135 F.E.R.C. ¶ 61,022, at P 87. P3, involving an industry group that represents independent power producers, explicitly connected state subsidies to buyer market power, pointing to Maryland and New Jersey natural gas subsidies as evidence that "buyer market power has proven to be a recurring and pervasive problem in organized capacity markets." *Id.* at P 20. The Pennsylvania Public Utility Commission made a similar argument, claiming that the net-short requirement created an "unwarranted loop hole giving a state-supported seller that does not itself serve load the incentive to make an uncompetitively low offer that cannot render the seller net-short." *Id.* at P 80. The New England Power Generators Association (NEPGA) made a similar observation in arguing against an exemption from mitigation for state-supported resources, arguing that "states are not neutral arbiters but instead represent interests on the buyer side of the capacity market." *ISO New England, Inc.*, 135 F.E.R.C. ¶ 61,029, at P 114.

net-short position (states, after all, technically are not buyers of capacity).[101] However, despite FERC's decision to mitigate all uneconomic entry, regardless of the entrant's incentives,[102] FERC and PJM continued to insist that its concern was ensuring that the MOPR was effective at protecting consumers from buyer market power.[103] The Commission also insisted that its examples were merely illustrative, and that "the evasion of the net-short requirement can come in a variety of forms, some unforeseen, and attempting to revise this provision to account for those scenarios may simply lead to further opportunities for gaming."[104]

The solution, according to FERC and PJM, was to eliminate the net short requirement altogether. The Commission pointed out that it would be irrational for a resource to submit a below-cost bid unless it thereby reduced the price it paid for capacity.[105] This logic persuaded the Commission that it could eliminate the net short requirement without interfering with the behavior of independent generators.[106] The fact that firms had managed to circumvent the net buyer screen convinced FERC that "providing this [net buyer] exemption from the MOPR based on perceived incentives of an entity will be ineffective at protecting against buyer market power."[107] For these reasons, FERC concluded that the net-short requirement was "ineffective and unnecessary."[108]

b. Eliminating the Impact Screen

In the same Order, FERC eliminated the impact screen, which had exempted from mitigation bids that did not affect the price of capacity.[109] By 2011, FERC concluded that uneconomic capacity bids could deter generator entry even if the bid did not affect the capacity price.[110] The Commission offered two reasons to

101. The PJM Internal Market Monitor appeared to endorse a similar idea in supporting the proposal to eliminate the net-short requirement, arguing that the New Jersey statute circumvented the net-short requirement and violated the "spirit and intent of the MOPR, given that the sell offer at issue could in fact be regarded as net-short when taking into account the status of New Jersey ratepayers (the buyers)." 135 F.E.R.C. ¶ 61,022, at P 81.

102. FERC indicates that natural gas and coal are especially vulnerable to price suppression. *See id.* at P 39.

103. *Id.* at P 88.

104. *Id.* at P 90.

105. 135 F.E.R.C. ¶ 61,022, at P 49. As discussed in more detail in Part III, PJM conflated below-cost bids with below-CONE bids. Generators have legitimate reasons to submit below-CONE bids if they have other sources of revenue, whereas below-cost bids are more likely to indicate a market power problem. .

106. *Id.* at P 89.

107. *Id.* at P 88.

108. *Id.* at P 86. This decision was also a response to a complaint submitted by the PJM Power Providers Group (P3), which also proposed eliminating the net short requirement. *See id.* at PP 76-77; 103 F.E.R.C. ¶ 61,201, at PP 28-29.

109. Specifically, PJM did not mitigate capacity market bids unless they decreased the capacity price either by (a) $25 MW per day, or (b) at least 20%. If a resource failed the conduct screen, PJM would rerun the capacity auction without the auction without the resource to determine if the resource actually suppressed capacity prices. The magnitude of price suppression required to trigger PJM's impact screen differed by region because PJM applied a different impact screen to different parts of the market. In some capacity zones, a bid failed the impact screen if it suppressed the price by 20%. In other zones, a bid would not fail the impact screen unless is suppressed the capacity price by 30%. *See* 135 F.E.R.C. ¶ 61,022, at PP 91, 101.

110. *Id.* at P 101 (explaining that eliminating the impact screen would have "the ancillary benefit of simplifying the mitigation process.").

justify this decision.[111] First, FERC argued that "even a small change in the clearing price from a below-cost offer can harm competition."[112] And second, the Commission was concerned about "the joint effect of multiple below-cost offers."[113] FERC explained that "even if one were to accept that a below-market offer with no material effect on prices should not be mitigated because it does no harm, such a position provides no comfort as the combined effects of several such offers might well affect prices."[114]

FERC was thus concerned that multiple below-cost bids could displace a resource that otherwise would have cleared the capacity market—and raised the clearing price—if the LSE had not submitted below-cost bids. As with its decision to eliminate the net short requirement, FERC's decision to eliminate the impact screen was motivated by concern that the test was under-inclusive and failed to deter market power abuses by net buyers of capacity.

c. Conduct Screen

The Commission further limited the discretion afforded to market participants by increasing the conduct screen from 80% to 90% of net CONE.[115] PJM argued, and the Commission agreed, that an 80% conduct screen "institutes an unreasonable tolerance for below-cost offers that can evade the MOPR and suppress prices to a considerable degree."[116] Once again, FERC was concerned that the previous mitigation rule failed to curb market power abuses, here claiming that bids that are slightly below net CONE could prevent capacity markets from incentivizing needed market entry. The Commission recognized that "estimating project costs is a complex process and that the PJM-determined estimates are, like all estimates, imperfect."[117] Nonetheless, FERC's anxiety about buyer market power convinced it that its previous Order had given market participants too much discretion. It therefore accepted ISO-NE's proposal to increase the conduct screen to ninety percent net CONE reflected "a reasonable balance of interests."[118]

On its own, the decision to increase the conduct screen to 90% net CONE might not have had a dramatic effect on the PJM capacity market. After all, until the 2011 Order, the PJM MOPR applied only to net buyers.[119] However, by simultaneously eliminating the net buyer requirement and increasing the conduct screen, the Commission left many independent power producers—the entities that are supposed to compete to provide low-cost service—with little discretion to enter the market based on their own assessment of whether it would be profitable for them to participate in the PJM market.

111. FERC offered only eight paragraphs to explain its initial Order and five when it denied petitions for rehearing. *Id.* at PP 101-09; *PJM Interconnection, L.L.C.*., 137 F.E.R.C. ¶ 61,145, at PP 61-64.

112. 137 F.E.R.C. ¶ 61,145, at P 62.

113. 135 F.E.R.C. ¶ 61,022, at P 106.

114. *Id.*

115. *See id*. at P 66 ("[W]e accept PJM's proposal to raise the conduct screen to 90 percent of Net CONE, from the current 80 percent threshold.").

116. 135 F.E.R.C. ¶ 61,022, at P 67.

117. *Id.* at P 68.

118. 135 F.E.R.C. ¶ 61,022, at P 73.

119. *Id.* at P 87.

d. Extending the MOPR to State-Subsidized Resources

PJM's 2011 price floor reforms also extended the MOPR to resources that had previously been exempted from mitigation. Prior to the 2011 filings, PJM's MOPR did not apply to planned resources that were developed in response to state mandates.[120] PJM and FERC eliminated this exemption because, as discussed above, they concluded that states could manipulate capacity market auctions.

Once the Commission determined that states, like net buyers, had both the incentive and ability to manipulate capacity markets, it extended PJM's MOPR to state-subsidized resources that were able to suppress the price of capacity.[121] The Commission reiterated that "[t]he very purpose of the MOPR . . . is to hinder such uneconomic entry, i.e., to ensure that an offer that may be the result of buyer market power does not clear at its artificially low level, thereby injecting uneconomic supply into the market."[122] According to the Commission, market manipulation "has the effect of disrupting the competitive price signals that PJM's RPM [reliability pricing model] is designed to produce, and that PJM as a whole, including other states, rely on to attract sufficient capacity."[123]

FERC was explicit that its decision to eliminate the state policy exemption was based on its (erroneous) view that states were themselves exercising buyer market power.[124] Because the Commission was concerned about market power abuses—not price suppression itself—it continued to exempt from mitigation certain facilities that received state support, including wind, solar, and demand response aggregators.[125] The Commission pointed out that, because these resources are intermittent and have unusual cost structures, they are limited in the amount of capacity that they can sell into the market.[126] As a result, these resources were "a poor choice for any entity attempting to suppress capacity prices."[127] Thus, although the Commission extended the PJM MOPR to some resources that received state support, it declined to mitigate resources that could not be used to manipulate capacity market prices.

e. Cumulative Effects of PJM's 2011 Changes

Before 2011, FERC assumed that only resources that had a clear interest in and demonstrated ability to suppress capacity prices should be mitigated. By 2011, FERC expanded the scope of mitigation across a variety of metrics, including the net short requirement, the impact screen, the conduct screen, and the state-mandated exemption, while simultaneously limiting the discretion afforded to resources subject to mitigation.[128] Note, though, that the 2011 PJM reforms were not designed to shield wholesale markets from state policy preferences or protect

120. *Id.* at P 124.
121. *Id.* at P 139.
122. *Id*. at 104.
123. 137 F.E.R.C. ¶ 61,145, at P 3.
124. 135 F.E.R.C. ¶ 61,022, at PP 127, 139.
125. *Id.* at P 152.
126. *Id.* at P 153.
127. 137 F.E.R.C. ¶ 61,145, at P 110.
128. 135 F.E.R.C. ¶ 61,022.

an idealized vision of wholesale markets in which resources compete free of outside influence, but rather to serve the more mundane goal of preventing market power abuses by net buyers of capacity. That is why FERC reiterated, time and again, that "[t]he very purpose of the MOPR . . . is to hinder such uneconomic entry, i.e., to ensure that an offer that may be the result of buyer market power does not clear at its artificially low level, thereby injecting uneconomic supply into the market."[129]

3. From Market Power to Price Suppression

In 2018 and 2019, FERC further expanded the PJM MOPR, determining that PJM should mitigate bids submitted by any resource that received state support.[130] The Commission abandoned the theory that price suppression was problematic merely as a means of facilitating market power abuses and instead began treating every bidding strategy or state policy that suppressed capacity prices as problematic.[131]

Specifically, in June 2018, FERC found that the two capacity market reforms PJM had proposed were unjust and unreasonable.[132] PJM had already laid the groundwork for FERC's Order in 2017 when it asked FERC to approve proposed revisions to its capacity market.[133] PJM explained that the reforms were needed not to mitigate market power abuses, but rather to address "the evolving circumstances presented by resources that receive out-of-market support."[134] FERC rejected both of PJM's proposals, finding that they failed to "protect the integrity of competition in the wholesale capacity market against unreasonable price distortions and cost shifts caused by out-of-market support."[135] For the first time, the Commission did not link price suppression in PJM to market manipulation.[136] In fact, the Commission expressly rejected the market power justification that had previously formed the basis of FERC's mitigation orders, stating that "state-subsidized resources—not just entities exercising buyer-side market power—can cause significant price suppression."[137]

129. *Id.* at P 104; *see also id.* at PP 70, 86 ("We find persuasive PJM's assertion that the revised 90 percent threshold strikes a reasonable balance between protecting against unreasonable exercises of market power and recognizing the imperfection of administrative estimates and the burden of the cost justification process.") ("We accept PJM's proposal to eliminate the net-short requirement. The purpose of this provision is to focus the MOPR on entities with the incentive to exercise buyer market power.").

130. *Calpine Corp. v. PJM Interconnection, L.L.C.*, 163 F.E.R.C. ¶ 61,236, at P 5 (2018) ("Although the role of the MOPR, in PJM, originally was limited to deterring the exercise of buyer-side market power, its role subsequently expanded to address the capacity market impacts of out-of-market state revenues.") (citing 135 F.E.R.C. ¶ 61,022, at PP 139–43).

131. *Id.*

132. *Id.* at P 6.

133. *Id.* at P 14.

134. 163 F.E.R.C. ¶ 61,236, at P 32. FERC rejected PJM's MOPR-Ex proposal in part because it provided a categorical exemption for renewable resources developed pursuant to a state Renewable Portfolio Standard (RPS). *See id.* at PP 100, 105 ("PJM's justifications do not adequately support the disparate treatment between resources receiving out-of-market support through RPS programs and other state-supported resources.").

135. *Id.* at P 150.

136. *Id.* at P 106.

137. *Id.*

This set the stage for FERC's December 19, 2019 Order, in which the Commission directed PJM to submit a replacement rate that extended the "old" MOPR to include virtually all resources that receive non-wholesale market compensation.[138] The MOPR continued to mitigate new natural-gas fired resources because those resources "remain able to suppress capacity prices."[139] What changed was that the Commission determined that the PJM MOPR should now apply to "all new and existing, internal and external, State-Subsidized Resources that participate in the capacity market, regardless of resource type."[140] Moreover, FERC defined subsidy broadly to mean "[a] direct or indirect payment, concession, rebate, subsidy, non-bypassable consumer charge, or other financial benefit that is a result of any action, mandated process, or sponsored process of a state government, a political subdivision or agency of a state, or an electric cooperative formed pursuant to state law."[141]

The Commission adopted such an expansive definition of subsidy because it felt that price suppression—whether a result of market manipulation or not—could undermine capacity markets and prevent the PJM market from procuring sufficient resources.[142] FERC explained that all "subsidized resources distort prices in a capacity market that relies on competitive auctions to set just and reasonable rates."[143] For that reason, the Commission claimed that it was necessary to mitigate any resource that receives a state subsidy so that the "capacity market [is able] to send price signals on which investors and consumers can rely to guide the orderly entry and exit of economically efficient capacity resources."[144]

The December 2019 PJM MOPR differs from the 2006 and 2011 versions in at least two respects. First, the Commission described price suppression as problematic in its own right and not simply as a means of exercising market power. The Commission has, at different times, offered different explanations of why it is concerned about price suppression.[145] For example, when FERC initially argued that aggressive mitigation was needed in eastern capacity markets (in ISO-NE), it claimed that price suppression undermined "investor confidence."[146] Then, when FERC rejected both of PJM's proposals in 2018, it explained that additional mitigation was needed to protect "market integrity."[147] By December 2019, FERC asserted, without offering an explanation, that state subsidies "reject the premise of the capacity market[s]."[148] In fact, since the FPA reserves to states authority over generation facilities, if any tension does exist, it stands to reason that capacity markets—not state subsidies—are in need of reform.

138. *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 F.E.R.C. ¶ 61,239 at P 2 (2019).

139. *Id.* at P 42.

140. *Id*. at P 50.

141. *Id*. at 67.

142. *Id.* at P 68.

143. 169 F.E.R.C. ¶ 61,239, at P 5.

144. *Id.* at P 41.

145. *Id.* at P 15 (As discussed in Part V, price suppression is only problematic when it is used by net buyers to engage in market manipulation).

146. This phrase appeared in the ISO-NE proceeding, discussed later in this Part. *ISO New England Inc.*, 162 F.E.R.C. ¶ 61,205, at P 21 (2018).

147. 169 F.E.R.C. ¶ 61,239, at PP 15-16.

148. *Id.* at P 17.

Second, the 2019 reforms subjected a larger percentage of resources to mitigation than did previous PJM MOPRs. According to Commissioner Glick, the "sweeping definition of subsidy . . . will potentially subject much, if not most, of the PJM capacity market to a minimum offer price rule."[149] By defining "subsidy" to include "any resource that receives any financial support for a state"[150]—regardless of whether the subsidy supports a goal that is within the state's sphere of jurisdiction or was designed to offload costs onto other states—the Commission has ensured that a significant percentage of resources that would like to enter the PJM market will not receive capacity market revenue unless the market price rises above the administratively-determined price floor.

PJM's 2019 MOPR reform is even more significant in light of the increasing role that capacity markets play in determining resource entry and exit. By design, capacity markets are supposed to make sure that there is sufficient revenue to attract the resources that are needed to ensure the reliable provision of electricity. For example, the Commission has described PJM's capacity market as creating the "price signals on which investors and consumers rely to guide the orderly entry and exit of capacity resources."[151] Similarly, the PJM Market Monitoring Unit (MMU), which is an independent body that conducts periodic reviews of PJM markets,[152] has stated that capacity market revenue plays a "critical role" in covering total costs for certain resources, such as natural gas combined cycle units, in PJM markets.[153]

B. History of Price Mitigation in NYISO

NYISO adopted its own buyer mitigation rule in 2008.[154] Like PJM, NYISO first limited mitigation to net buyers of capacity that had both the incentive and ability to suppress capacity market prices, though over time NYISO has extended mitigation to most resources that submit bids that are below their CONE.

1. The Origins of Price Mitigation in NYISO

NYISO adopted a price mitigation rule in response to concerns that net buyers that distributed electricity to New York City customers would submit below-

149. *Id.*

150. *Id.* at P 15.

151. *Id.* at P 156.

152. *See* PJM, MARKET MONITORING UNIT, https://www.pjm.com/committees-and-groups/committees/mmuac.

153. MONITORING ANALYTICS, LLC, STATE OF THE MARKET REPORT FOR PJM 328 (2020), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume2.pdf (Mar. 12, 2020). Similarly, in 2017, PJM noted that a "diminishing energy market returns for supply resources" had "resulted in a shift to the capacity market for the greater proportion of returns for generating units' recovery of their total investment costs." PJM, PROPOSED ENHANCEMENTS TO ENERGY PRICE FORMATION 7, https://wired.pjm.com/-/media/library/reports-notices/special-reports/20171115-proposed-enhancements-to-energy-price-formation.ashx?la=en.

154. *NYISO*, 124 F.E.R.C. ¶ 61,301, at P 8 (2008).

cost capacity bids to lower the price of capacity, and that such bids would discourage needed generation from entering the market.[155] To prevent this from happening, NYISO followed PJM's lead in 2008 and imposed a price floor on net buyers of capacity.[156]

In 1998,[157] to restructure the power sector, the state of New York ordered ConEd, one of the two utilities that had previously provided both generation and transmission services to virtually all New York City customers,[158] to divest itself of most of its generation assets.[159] New York's goal was to shift away from cost-of-service rate regulation and towards a market in which generators competed with each other to provide low-cost electricity.[160]

However, just a year later, ConEd and the New York Power Authority (NYPA), the other large buyer in New York City, each procured 500 MW of capacity via bilateral contracts.[161] These acquisitions sparked concern that the two utilities would use their newly acquired generation assets to drive down the price of capacity. As in PJM, the Commission observed that "[l]arge net buyers may have both the incentive and the ability to depress prices through uneconomic entry."[162] The Commission claimed that this type of market manipulation could undermine the "price signals" needed "to alert investors when increased entry is needed."[163] That, in turn, could "inhibit new entry, and thereby raise prices and harm reliability, in the long-run."[164]

NYISO's buyer market power rule was simpler than PJM's. Resources subject to mitigation were required to enter the NYISO capacity auction by offering to sell capacity "at a price at or above the applicable offer floor until their capacity clears 12 monthly auctions."[165] NYISO set the price floor at 75% net CONE.[166] This meant that, with limited exceptions,[167] net buyers in the New York region could not offer to sell capacity for less than 75% of whatever cost NYISO expected

155. *Id.* at PP 2, 3, 4 (describing buyer and seller market power in New York City). As of fall 2020, New York's BSM applies only in the New York region, though in October 2020, a group of generators requested that FERC expand BSM to the entire state.

156. *Id.* at P 21. To this day, NYISO's buyer mitigations rules apply primarily in the New York City area.

157. *Id.* at P 2.

158. 124 F.E.R.C. ¶ 61,301, at P 2.

159. *Id.* at P 2 ("In 1998, Consolidated Edison of New York, Inc. (ConEd) divested most of its generators in three bundles – creating a high degree of market concentration for generation in New York City").

160. *Id.*

161. *NYISO,* 122 F.E.R.C. ¶ 61,211, at P 5 (2008).

162. *Id.* at P 101 ("A large net buyer could acquire new capacity that is not needed in the market and whose costs exceed the market price. Such an investment would be inefficient, the net buyer would lose money on the capacity, and no rational seller would knowingly make such an investment. But the investment could benefit the net buyer because the additional capacity could reduce the market price for capacity and lower the net buyer's total capacity bill. If the newly added capacity represents only a portion of the net buyer's total capacity needs, the reduction in the buyer's total capacity bill caused by the lower prices could more than offset the loss on the newly added capacity investment. As a result, a large net buyer could have an incentive to make such an inefficient investment.").

163. *Id*. at 103.

164. *Id*.

165. *NYISO*, 170 F.E.R.C. ¶ 61,121, at P 2 (2020).

166. 122 F.E.R.C. ¶ 61,211, at P 107.

167. *Id*. at P 94 (See infra discussion of Special Case Resources).

that type of generator to need from capacity markets until they had cleared the capacity market for a year.[168] In NYISO, the price floor applied to all new entry unless (1) the market clearing price in the first year was higher than the offer floor (known as Part A of the NYISO mitigation exemption test), or (2) the average post-entry market clearing prices in the first three years after entry is higher than the new unit's entry cost (known as Part B of the NYISO mitigation exemption test).[169]

These two exceptions operated like the impact and conduct screens PJM adopted in 2006 and abandoned in 2011.[170] By definition, a bid below the price floor will not affect the market clearing price when the average clearing price is higher than the price floor. Similarly, when the average market clearing price is higher than the unit's cost of entry, then the resource *should* enter the market. The high capacity price signals the need for new generation, and the fact that the unit could recover its costs from the capacity market would indicate that the resource is able to sell capacity at a profit.

As in PJM, FERC's concern was initially limited to net buyers.[171] According to the Commission, net buyers are "the only market participants with an incentive to sell their capacity for less than its cost."[172] The Commission reasoned that, unlike net buyers, net sellers would enter the market only when they could expect to make a profit.[173] Because other market participants had no incentive to offer to sell capacity at a loss, FERC felt that bids submitted by net sellers could be trusted to reflect sellers' actual views about their own costs and the profitability of entering the NYISO electricity market.[174]

NYISO also initially did not mitigate bids if it was difficult to calculate the resource's cost of entry or if the resource was unlikely to facilitate market power abuses.[175] To that end, NYISO created an exemption for Special Case Resources (SCRs). Special Case Resources refer to demand response resources, which describe firms that curtail electricity use in exchange for compensation.[176] Special Case Resources used to be permitted to determine for themselves their capacity market bids.[177] For example, when FERC first approved NYISO's MOPR, it pointed out that "[t]here is no basis to establish an offer floor for demand response resources based on the cost of new generation entry because there is not necessarily any connection between net CONE by generation and net CONE by demand

168. *Id*. at P 98.

169. 122 F.E.R.C. ¶ 61,211, at PP 98, 117.

170. These exceptions have not been abandoned, but FERC has rejected a recent NYISO proposal to modify these exemptions to better accommodate New York's decarbonization goals. See, *NYISO*, 172 F.E.R.C. ¶ 61,206, at PP 4-5, 14 (2020).

171. 122 F.E.R.C. ¶ 61,211, at P 106 ("NYISO must specify in its proposed tariff language that the mitigation of uneconomic entry applies only to net buyers").

172. *Id.*

173. *Id.*

174. *See* 122 F.E.R.C. ¶ 61,211, at P 106 ("New capacity offered by net sellers of capacity would not profit from this strategy, and so would not enter the ICAP market with uneconomic capacity; it will only enter the market when the market sends the price signal indicating that profit can be earned by entering the market.").

175. *Id*. at P 120.

176. *Id.*

177. 122 F.E.R.C. ¶ 61,211, at P 120.

response resources."[178] Though the Commission did not go into detail, one can imagine the challenges of examining every single bidder and trying to determine the opportunity costs it incurs in reducing electricity at a given moment. The Commission was therefore correct that "it is not clear, nor is it proposed here, how NYISO would determine the cost of SCR [special case resource] entry or if that entry was uneconomical."[179]

2. Tailoring the Rule to Monopsony Abuses

Shortly after instructing NYISO to limit mitigation to net buyers, FERC reversed itself on rehearing and approved NYISO's proposal to extend buyer mitigation to "all uneconomic entry."[180] Like PJM, NYISO was concerned that the net buyer requirement was under-inclusive and failed to prevent utilities from manipulating capacity prices.[181] Thus, in 2008, three years before PJM eliminated its net buyer requirement, FERC accepted NYISO's view "that limiting uneconomic entry mitigation measures to net buyers could undermine enforcement because buyers may behave strategically to avoid categorization as net buyers."[182]

NYISO adopted its buyer-side market power mitigation rule after ConEd and the NYPA entered into bilateral contracts which, as discussed in the previous subpart, could be used to manipulate capacity prices. Both utilities procured long-term capacity contracts for differences. Their counterparties therefore had an incentive to offer to sell capacity for $0, regardless of the capacity market price. Since the two New York City utilities had entered into precisely the type of contract that could be used to manipulate capacity prices, the Commission was concerned, as it was two years later in PJM, that New York City buyers were behaving strategically to "evade mitigation measures."[183]

Since 2008, FERC and NYISO have steadily, though unevenly, increased the number of resources that are exempted from NYISO's buyer side mitigation rule. Since 2008, FERC has issued at least ten Orders directing NYISO to reform its buyer side mitigation power rule.[184] FERC's first intervention came in March

178. *Id*.

179. *Id*.

180. *New York Indep. Sys. Operator, Inc.*, 131 F.E.R.C. ¶ 61,170, at PP 52–54 (2010) (finding that NYISO complied with the Commission's September 30, 2008 order directing NYISO to reflect its ruling that application of the MOPR should not be limited to net buyers).

181. 124 F.E.R.C. ¶ 61,301, at P 28.

182. *Id.*

183. *Id.*

184. 122 F.E.R.C. ¶ 61,211, at P 120 (exempting SCRs from mitigation); 124 F.E.R.C. ¶ 61,301, at P 41 (determining that SCRs should be subject to mitigation); 131 F.E.R.C. ¶ 61,170, at PP 106-07, 137 (approving NYISO's definition of mitigation and proposed mitigation period and excluding subsidized resources from mitigation); 150 F.E.R.C. ¶ 61,208, at P 31 (reversing decision to exclude subsidized payments from mitigation); 153 F.E.R.C. ¶ 61,022, at P 105 (denying complaint challenging extension of buyer-side market power mitigation rules to SCRs); 158 F.E.R.C. ¶ 61,137, at P 30 (finding that application of buyer-side mitigation rules to SCRs was unjust, unreasonable or unduly discriminatory); 170 F.E.R.C. ¶ 61,118, at P 19 (denying requests for clarification and rehearing on order denying complaint seeking to extend mitigation to resources retained pursuant to a Reliability Support Service Agreement); 170 F.E.R.C. ¶ 61,119, at PP 36–37 (denying complaint challenging application of buyer-side market power mitigation rules to electric storage resources); 170 F.E.R.C. ¶ 61,120, at P 16 (approving application of buyer-side mitigation rules to SCRs and initiating a hearing to determine whether payments from certain retail-level demand response programs should be excluded from offer floor calculation);

2008, when the Commission broadly exempted SCRs from mitigation in order to avoid "erect[ing] a barrier to entry of demand response into the markets," and because it lacked a "basis to establish an offer floor for demand response resources."[185]

Just six months later, however, in September 2008, the Commission reversed course and found that "it is appropriate for NYISO's in-City market mitigation rules to apply to SCRs."[186] The Commission directed NYISO "to impose appropriate market power mitigation measures when conduct departs significantly from what would be expected under competitive market conditions."[187] The Commission did not explain why it felt that it was now possible to calculate the cost of entry for demand response resources when, just six months earlier, it had said that it was unable to do so. NYISO and FERC spent two year formalizing a rule that would mitigate SCRs, but in 2011, FERC accepted NYISO's price floor.[188] At that point, NYISO's buyer-side market power mitigation had very few exceptions and applied to nearly all resources that entered the New York City capacity market.

NYISO's expansive buyer-side market power mitigation rule lasted until 2015, when the Commission began directing NYISO to exempt from mitigation resources that lacked either the incentive or the ability to suppress capacity market prices.[189] FERC found that some resources—especially renewables and demand response resources—were unable to suppress capacity market prices.[190] To that end, between 2015 and 2017, the Commission issued three Orders instructing NYISO to exempt such resources from mitigation.[191]

The first came in February 2015, when FERC instructed NYISO to create a "competitive entry exemption" that would "allow for private investors, relying solely on market revenues, to enter the capacity market unmitigated upon certifying that they are a purely merchant investment, with no out of market subsidy."[192] This requirement can be understood as a more limited version of the net buyer requirements.[193] Both net buyer requirements and competitive entry exemptions are supposed to ensure that mitigation is limited to resources that have an incentive to mitigate capacity market prices. However, competitive entry exemptions are more restrictive than net buyer requirements because they mitigate only resources that receive revenue through subsidies or retail markets. Thus, under NYISO's competitive entry exemption, resources whose revenues depend entirely on wholesale markets are permitted to bid below the price floor, but resources that enjoy

170 F.E.R.C. ¶ 61,121, at P 16 (accepting in part and rejecting in part proposed renewable resource exemption and self-supply exemption rules).

185. 131 F.E.R.C. ¶ 61,170, at P 44.

186. 124 F.E.R.C. ¶ 61,301, at P 41.

187. *Id.*

188. The Commission rejected a few elements of the NYISO rule. For example, it rejected NYISO's proposal that resources that reenter the capacity market after a period of absence be mitigated a second time. NYISO amended, and the Commission approved, new performance measurement standards for SCRs a year later. See 124 F.E.R.C. ¶ 61,301, at P 99.; *NYISO Inc.*, 135 F.E.R.C. ¶ 61,020 at P 1 (2011).

189. *Consol. Edison Co. N.Y., Inc.,* 150 F.E.R.C. ¶ 61,139 (2015); *Consol. Edison Co. N.Y., Inc.,* 152 F.E.R.C. ¶ 61,110 (2015).

190. 150 F.E.R.C. ¶ 61,139, at P 45.

191. 150 F.E.R.C. ¶ 61,139, at P 2; 152 F.E.R.C. ¶ 61,110, at P 11; 158 F.E.R.C. ¶ 61,137, at P 1.

192. 150 F.E.R.C. ¶ 61,139, at PP 1, 4.

193. *Id.* at P 3.

revenue streams from other sources, such as from state subsidies or retail markets, remain subject to mitigation.

Shortly after FERC directed NYISO to develop a competitive entry exemption, in October 2015, the Commission instructed NYISO to carve out another exemption for resources such as wind and solar that "have limited or no incentive and ability to exercise buyer-side market power to artificially suppress ICAP market prices."[194] Then, in 2017, when the Commission ordered NYISO to adopt a blanket exemption for new SCRs, FERC again explained that mitigation should not extend to resources that "have limited or no incentive and ability to exercise buyer-side market power."[195]

As the Commission explained,

> [B]ecause a purely merchant generator places its own capital at risk when it invests in a new resource, any such resource will have a strong incentive to bid its true costs into the auction, and it will clear the market only when it is cost effective. As such, a bid from a merchant project below Net [cost of new entry (CONE)] likely represents the economics of that resource, and if it does not, the resource will not be able to recover its costs. The purpose of the MOPR, however, is not to protect a merchant resource from making a poor investment decision with its own capital.[196]

FERC therefore recognized that buyer-side market power mitigation rules substituted an administrator's view about the cost of entering the NYISO market for the merchant's assessment of its own costs.[197] To reduce the magnitude of this intervention, between 2015 and 2017, FERC sought to rein in NYISO's buyer mitigation rule so that resources that were not in a position to exercise buyer market power were able to participate in the NYISO capacity market on their own terms.

In those years, FERC repeatedly argued that it was unnecessary, and perhaps even beyond the Commission's delegated authority, to mitigate resources that lacked the incentive and ability to manipulate capacity auctions. For example, when FERC created a competitive entry exemption in 2015, the Commission found "that NYISO's current buyer-side mitigation rules are unjust and unreasonable because they are unnecessarily applied to unsubsidized, competitive entrants who have no incentive to inappropriately suppress capacity market prices."[198] Similarly, in October 2015, the Commission declared it "unjust, unreasonable, or unduly discriminatory or preferential to apply NYISO's buyer-side market power mitigation rules to certain narrowly defined renewable and self-supply resources that have limited or no incentive and ability to exercise buyer-side market power."[199] The Commission explained that its ruling "is consistent with the Commission's generally-applied minimum offer price rule policy; specifically, that buyer-side market power mitigation rules are intended to address market power exhibited by certain entities seeking to lower capacity market prices."[200] FERC

194. 153 F.E.R.C. ¶ 61,022, at P 2. The Commission also directed NYISO to exempt certain self-supply resources for similar reasons.

195. 158 F.E.R.C. ¶ 61,137, at P 31.

196. 150 F.E.R.C. ¶ 61,139, at P 3 (quoting *PJM Interconnection, L.L.C.*, 143 F.E.R.C. ¶ 61,090, at P 57 (2013)).

197. *Id.*

198. 150 F.E.R.C. ¶ 61,139, at P. 45.

199. 153 F.E.R.C. ¶ 61,022, at P. 2.

200. *Id.* at P 10.

cautioned against "the unnecessary mitigation of resources that derive limited or no benefit from lower prices."[201]

Thus, for a short period in the mid-2010s, FERC felt that buyer-side market power mitigation rules in NYISO had become excessively intrusive, and it took steps to tailor NYISO's MOPR to resources that could actually abuse their market power. In fact, as recently 2017, FERC Chairman Norman Bay observed in a concurrence that the label "buyer-side market power" had become "imprecise and somewhat of a misnomer, for it has come to have a broader meaning than what the name might otherwise suggest."[202] Bay argued that "the MOPR suffers from a troubling lack of coherence that calls into question the soundness of its underlying rationale."[203] He therefore urged the Commission to develop a more coherent approach to buyer-side market power mitigation rules.

3. Abandoning the Market Power Justification

FERC's attempts to pare back mitigation in the NYISO market proved short-lived. On February 20, 2020, the Commission issued four separate Orders, each of which directed NYISO to expand its buyer-side market power mitigation rule.[204] FERC directed NYISO to mitigate the very resources that, just three years earlier, it had found were unable to facilitate market power abuses.[205] Among other things, FERC instructed NYISO to impose a cap on the renewables exemption[206] and extend mitigation beyond net buyers to demand-side resources that had previously been exempted[207] and to storage resources.[208]

The Commission continued to refer to NYISO's MOPR as a buyer-side mitigation rule, but the logic it marshaled to defend the 2020 reforms suggests that the FERC has become more concerned about price suppression than market power. In all four Orders, FERC explained that its primary concern is "protect[ing] the capacity market from the price suppressive effects of resources receiving out-of-market support."[209] Although the Commission asserted that its decision recognized "the need to protect NYISO's ICAP markets from the potential for SCRs to exercise buyer-side market power,"[210] FERC did not discuss whether SCRs are buyers at all—in fact, the Order mitigates bids submitted by net sellers as well as bids submitted by net buyers—and instead is based entirely on the ability of SCRs

201. 158 F.E.R.C. ¶ 61,137, at P. 30.

202. 158 F.E.R.C. ¶ 61,137 (Bay, Comm'r, concurring).

203. *Id*.

204. *See* 170 F.E.R.C. ¶ 61,118; 170 F.E.R.C. ¶ 61,119; 170 F.E.R.C. ¶ 61,120; 170 F.E.R.C. ¶ 61,121.

205. *Compare* 158 F.E.R.C. ¶ 61,137, *with* 170 F.E.R.C. ¶ 61,118.

206. New York State Public Service Commission, et al. v. New York Independent System Operator, Inc., FERC Docket No. EL16-92.

207. 170 F.E.R.C. ¶ 61,119.

208. *Id.*; FERC also declined to expand the NYISO buyer-side mitigation rule to resources that are retained for reliability reasons. *See Indep. Power Producers of New York, Inc. v. New York Indep. Sys. Operator, Inc.*, F.E.R.C. ¶ 61,214 (2015).

209. *New York State Pub. Serv. Comm'n and New York State Energy Research and Dev. Auth. v. New York Indep. Sys. Operator, Inc*., 170 F.E.R.C. ¶ 61,119, at P 37 (2020).

210. *New York State Pub. Serv. Comm'n v. New York Indep. Sys. Operator, Inc.*, 170 F.E.R.C. ¶ 61,120 at P 19 (2020).

to suppress capacity market prices.[211] Nor did the Commission explain why resources that it had previously declared unable to manipulate capacity markets should now be subject to mitigation.

While the Commission's NYISO Orders have proceeded haphazardly, over the past decade, NYISO's buyer side mitigation rule has extended to resources that, by the Commission's own admission, cannot be used to manipulate capacity market prices. Unlike PJM, NYISO adopted a highly restrictive buyer mitigation rule as early as 2008. The Commission then narrowed the scope of mitigation in 2015, and again in 2017, because it felt that the NYISO buyer mitigation rule was being applied to resources that could not be used to manipulate capacity market prices. The Commission reversed course in February 2020, expanding the scope of NYISO's buyer market power rule and mitigating the very resources that the Commission had previously stated were unlikely to facilitate market power abuses.[212] And, in October 2020, two gas generators filed a complaint against NYISO asking FERC to increase the restrictiveness of buyer side mitigation and extend the price floor to the entire state.[213] In NYISO, as in PJM, the Commission now treats price suppression as problematic in its own right and not because it can occasionally enable market power abuses.

C. History of Price Mitigation in ISO-NE

While NYISO and PJM have relied on MOPRs to mitigate buyer market power since they first adopted capacity markets, ISO-NE originally relied on a different mechanism to address buyers' incentive to submit below-cost-capacity bids. Over the past decade, however, ISO-NE's buyer-side market power mitigation rule has converged with its neighbors in New York and the mid-Atlantic.[214]

1. ISO-NE's Alternative Price Rule

In 2006, the same year FERC approved PJM's capacity market, ISO-NE adopted something called an Alternative Price Rule (APR) to prevent net buyers from abusing their market power.[215] This rule was triggered when new capacity sought to enter the market at a price below the administratively-determined CONE (known as the "reference price").[216] But rather than administratively reprice *bids*

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211. *Id.* at P 20; *see also id.* at P 1 (Glick, Comm'r, dissenting) ("Today the Commission issues a series or orders addressing buyer-side market power mitigation rules in the NYISO capacity market. Notably, none of the orders is actually focused on buyers with market power.").

212. *See Calpine Corp. Dynegy, Inc., v. PJM Interconnection, LLC,* 169 F.E.R.C. ¶ 61,239, at P 161 (2019).

213. *See* FERC Docket No. EL21-7-000 at 1, 35 (Oct. 14, 2020).

214. *Devon Power LLC*, 115 F.E.R.C. ¶ 61,340, at P 113. Again, though, the buyer-side market power mitigation rule was designed to prevent LSEs from submitting bids that would "reduce the prices they must pay for existing capacity procured in the auction." *Id*.

215. *Id.* at PP 109-110.

216. *Id.* at P 17. Technically, ISO-NE subtracted a cent from that price at which the last bid from new capacity was withdrawn minus one cent or CONE, whichever was lower. As in NYISO, this was 75% of CONE. *Id.* at P 109 ("The rule applies when at least some of the offers from new capacity or imports are below .75 times CONE and the Market Monitor concludes that such low offers are not consistent with long run average costs, opportunity costs, or other reasonable economic measures. Capacity submitting such bids is deemed to be "out-of-market." When any submitted bids are deemed out-of-market, the capacity clearing price will be reset when the following conditions are met . . . If these conditions are met, the clearing price for the applicable capacity

submitted by resources subject to mitigation, the APR administratively reset the *clearing* price.[217] ISO-NE would thus reset the capacity market clearing price when "(1) new capacity is needed, either system-wide or in an import-constrained zone; (2) there is adequate supply in the auction; and (3) at the auction clearing price, purchases from 'out-of-market' capacity are greater than the required new entry."[218] "Out of market" resources (ISO-NE uses the acronym OOM to describe them) describe all resources that receive a payment outside of ISO-NE's energy, capacity, and ancillary services markets.[219] OOM resources include resources that offer to enter ISO-NE's capacity market at a price that is below those resources' long-run average costs.[220] ISO-NE's internal market monitor, which is a department within ISO-NE, determines whether a resource receives out of market compensation. Absent a mitigation rule, resources that received state subsidies or that had entered bilateral contracts with an LSE were able to factor those revenues into their capacity bids. Thus, ISO-NE's APR was triggered only when ISO-NE faced a capacity shortfall and when OOM resources were sufficient to meet that shortfall.

The APR reset the clearing price to the price at which the market would have cleared had the mitigated bid not participated in the capacity auction.[221] If, for example, a net buyer submitted a bid that caused the clearing price to decline from $100,000 per 100 MW of capacity to $50,000 per 100 MW of capacity, the APR would reprice the capacity clearing price to $100,000.[222] By setting a new price for capacity, ISO-NE's APR removed the incentive for resources to manipulate ISO-NE's capacity market.

While ISO-NE did not, as NYISO and PJM did, include a net buyer requirement that limited the capacity repricing rule to net buyers, the rule was designed such that only net buyers would be affected.[223] In fact, when FERC accepted the *Devon Power* settlement, it explained that the APR was designed to prevent net buyers—and only net buyers—from abusing their market power:

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zone will be set to the lower of 1) the price at which the last bid from new capacity was withdrawn, minus $0.01 or 2) CONE.")

217. *Id.* at P 109. Of course, in one sense price floors also reprice the capacity market clearing price, because the decision to exclude a less expensive bid and replace it with a more expensive bid increases the clearing price. *See also id.* at P 19.

218. *Devon Power, LLC*, 115 F.E.R.C. ¶ 61,340, at P 109. The first condition was if the Installed Capacity Requirement (ICR) exceeded the amount of existing capacity. The second condition was met when the total amount of capacity offered into the FCA at the beginning of the auction was adequate to meet the ICR. The final condition was met when the amount of out-of-market capacity exceeded the need for new capacity and no new capacity cleared the market. *See ISO New England, Inc. & New England Power Pool Participants Committee*, 131 F.E.R.C. ¶ 61,065, at P 38 (2010).

219. 131 F.E.R.C. ¶ 61,065, at P 7.

220. *See* ISO-NE, INTERNAL MARKET MONITOR, https://www.iso-ne.com/markets-operations/market-monitoring-mitigation/internal-monitor/.

221. *Id.* at P 16. *Specifically*, ISO-NE reset the price such that it equaled the lower of (1) the estimated cost of entry, or (2) the amount bid by a generator not affiliated with the LSE that would have cleared but for the LSE's price suppressive bid. *See id.* at PP 84, 86.

222. *Id.* at P 39. *Technically*, ISO-NE would reprice the clearing price to the lower of $99,999.99 or the net CONE for that resource.

223. 131 F.E.R.C. ¶ 61,065, at P 76; *See also* 169 F.E.R.C. ¶ 61,239, at PP 6, 23; 115 F.E.R.C. ¶ 61,340, at P 153.

> In the absence of the alternative price rule, the price in the FCA could be depressed below the price needed to elicit entry if enough new capacity is self-supplied (through contract or ownership) by load. That is because self-supplied new capacity may not have an incentive to submit bids that reflect their true cost of new entry. New resources that are under contract to load may have no interest in compensatory auction prices because their revenues have already been determined by contract. And when loads own new resources, they may have an interest in depressing the auction price, since doing so could reduce the prices they must pay for existing capacity procured in the auction.[224]

To understand how the APR deterred market manipulation, imagine that two resources submit bids below their net CONE. One is affiliated with an LSE and the other is an independent generator that believes it can construct a power plant for less than whatever price ISO-NE's market monitor calculated to be that resource's CONE. The APR would disincentivize the LSE from submitting a below-cost bid because, by administratively increasing the price of capacity, the APR would force the LSE to pay the amount that it would have had to pay absent a bid from its generator. Generators that relied on capacity market revenues would benefit when the APR raised the price of capacity because doing so would increase the revenue they earned from the capacity market. Thus, while ISO-NE's APR initially differed from the MOPRs adopted in PJM and NYISO, it, too, was designed to prevent market power abuses by net buyers of capacity.[225]

2. Buyer-Side Market Power and Price Suppression

ISO-NE's APR lasted less than four years. Just two years after FERC instructed ISO-NE to develop an APR, a coalition of independent generators filed a complaint arguing that the APR was unjust and unreasonable because it failed to deter resources that received OOM support from clearing the ISO-NE capacity market.[226]

FERC agreed, finding that ISO-NE's APR was defective because it failed to mitigate market power abuses.[227] Specifically, FERC determined that the APR would likely never be triggered because OOM resources would enter the market even when the region did not need any additional capacity.[228] In ISO-NE's first two capacity auctions, 4,034 MW of new capacity cleared the market, and ISO-NE's internal market monitor determined that 3,351 MW of the capacity that entered the market was OOM.[229] The entry of so much capacity when the grid operator did not reprice the capacity market price ensured that the region had enough generation to meet the region's demand and therefore forestalled the need to trigger the APR.[230] For that reason, the Commission concluded that "sponsors of

224. *Devon* Power, *LLC,* 115 F.E.R.C. ¶ 61,340, at PP 27, 113 (explaining that the APR would "address high concentrations of market power.").

225. 115 F.E.R.C. ¶ 61,340, at P 27.

226. *ISO New England, Inc. and New England Power Pool Participants Committee*, 135 F.E.R.C. ¶ 61,029, at 13–20 (2011).

227. *Id.* at P 19.

228. *Id.* at PP 58-59.

229. 131 F.E.R.C. ¶ 61,065, at P 39 ("The APR was not triggered because, in each FCA, the amount of existing capacity exceeded the ICR. In addition, the IMM states that none of the capacity that was identified as OOM affected the prices in the first three FCAs.").

230. *Id.*

OOM resources that represent a large share of the load could circumvent the application of the APR for several years by investing in sufficient OOM resources to maintain a continuous surplus of capacity over that period that avoids the need for new in-market capacity."[231]

FERC was therefore concerned that OOM resources would facilitate market power abuses even when the APR was not triggered. The Commission noted that "OOM resources can affect prices even when no new capacity is needed, by displacing what would otherwise be the marginal, price-setting existing resource."[232] In doing so, "[a] new OOM resource can suppress the market clearing price even when no new capacity is needed, by displacing a marginal existing resource that would otherwise have set the market price."[233] This, the Commission claimed, meant that the "existing APR triggering conditions . . . may overlook situations in which an OOM resource may be used as an instrument of buyer market power."[234] FERC's concern was supported by ISO-NE's experience administering the APR. In its short four-year life, ISO-NE never applied the APR.[235]

FERC's fear that ISO-NE's APR had failed to prevent market power abuses led to a related concern, which was that the entry of OOM capacity would force consumers to pay for capacity they did not need. By increasing the price of capacity, the APR would therefore procure a resource that would otherwise not have cleared. At the same time, because the APR would not prevent the OOM resource from clearing, it would ensure that an additional supplier would clear: the OOM supplier would clear and the resource that cleared only because ISO-NE reset the capacity price would now clear. Only one of these resources was needed, but the APR ensured that both would enter the market. For that reason, FERC determined that ISO-NE's APR contributed to bloated reserve margins.[236] It explained that "ISO-NE has not offered a persuasive reason why . . . it is just and reasonable to require customers to incur unnecessary costs in order to purchase more capacity than the FCM was established to procure and that is needed for reliability."[237]

Based on these concerns, FERC rejected ISO-NE's APR and, in 2010, instructed the grid operator to develop a buyer market power mitigation rule "akin to those in PJM and NYISO."[238] FERC explained that a price floor "would deter

231. *Id*. at P 72.

232. *Id*. at P 70.

233. *Id*. at P 76.

234. 131 F.E.R.C. ¶ 61,065, at P 76.

235. *Id*. at P 45.

236. *See ISO New England, Inc. & New England Power Pool Participants Committee*, 135 F.E.R.C. ¶ 61,029 at PP 157–165 (2011).

237. *Id*. at P 163.

238. *Id*. at P 165.

the exercise of buyer-side market power"[239] and "spare customers the cost of procuring capacity in excess of the ICR—excess capacity that is not needed to meet ISO-NE's reliability objectives."[240]

Still, FERC continued to justify buyer-side market power mitigation rules as necessary to mitigate buyer market power, reasoning that a price floor would "deter the exercise of buyer-side market power and the resulting suppression of capacity market prices associated with uneconomic entry" by "preventing new resources from offering at prices that are significantly below their true net cost of entry."[241]

Although FERC ordered ISO-NE to develop a MOPR in 2011, it was not until 2013 that the grid operator proposed, and FERC accepted, ISO-NE's proposed reforms.[242] In February 2013, FERC accepted ISO-NE's proposal to adopt a price floor.[243] ISO-NE initially created an "asset-class specific minimum offer price rule" that created an "offer review trigger price" (ORTP, which is ISO-NE's acronym for net CONE) that applied to new resources that sought to enter ISO-NE's capacity market.[244] ISO-NE set the offer review trigger price at 100% of the estimated cost of new entry.[245] This meant resources subject to the price floor were not given any discretion whatsoever to deviate from the administratively determined price.[246]

Although FERC's 2013 ISO-NE Order was expansive, the Commission quickly recognized that this MOPR was excessively broad, and that it mitigated resources that were not in a position to exercise market power. Thus, as in NYISO, FERC accepted revisions that tailored the rule to resources that could exercise market power.[247] To that end, in 2014, FERC accepted ISO-NE's proposed Renewable Technology Resource (RTR) exemption on the ground that renewables were incapable of exercising market power.[248]

3. ISO-NE's Shift Toward Price Suppression

Four years later, however, price suppression replaced market power as the primary reason for mitigating capacity market bids. In 2018, ISO-NE submitted

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239. *Id.* at P 166. "First, if the offer floor is set at a level that approximates the net cost of entry of a new resource, offer-floor mitigation would deter the exercise of buyer-side market power and the resulting suppression of capacity market prices associated with uneconomic entry. By preventing new resources from offering at prices that are significantly below their true net cost of entry, new resources would not be able to lower the price of capacity significantly below competitive levels. As a result, there would be no financial reward for subsidizing new resources for the purpose of exercising buyer-side market power."

240. *Id.* at P 167.

241. 135 F.E.R.C. ¶ 61,029, at P 166. Unlike PJM and NYISO, FERC did not require ISO-NE to develop a test to determine whether a particular resource had the incentive or ability to exercise buyer-side market power, instead simply focusing on whether a resource's offer could "lower the price of capacity significantly below competitive levels."

242. *Id.*

243. *Id.* at P 372.

244. 142 F.E.R.C. ¶ 61,107, at P 7.

245. *Id.*

246. *See id.* at PP 15, 39.

247. *Id.*

248. *ISO New England Inc. & New England Power Pool Participants Committee*, 147 F.E.R.C. ¶ 61,173, at PP 83–84 (2014).

proposed tariff revisions that would include a new capacity auction process, called Competitive Auctions with Sponsored Policy Resources (CASPR).[249] Under CASPR, the annual capacity auction would consist of two stages. The first would maintain the then-existing process but would extend the MOPR to all resources that received state support.[250] At the end of the first auction, ISO-NE would run a substitution auction, which would permit existing resources that acquired capacity supply obligations in the primary auction to "offer a demand bid . . . indicating a willingness to permanently retire from all ISO-NE markets at a certain price."[251] Because the MOPR would not apply in the substitution auction, it would allow state-supported resources to "account for out-of-market revenues and offer at the lowest price at which they are willing to accept a capacity supply obligation."[252] The first step excluded every resource that was subject to mitigation. The second step allowed mitigated resources to offer to buy out resources that cleared the market.

When FERC accepted ISO-NE's proposal, it explained that, "[a]bsent a showing that a different method would appropriately address state policies, we intend to use the MOPR to address the impacts of state policies on the wholesale capacity market."[253] To a greater extent than the PJM and NYISO MOPRs, ISO-NE seems to be trying to strike a balance between accommodating state policy preferences and mitigating resources that receive out-of-market support. Still, like PJM and NYISO, the Commission has begun to treat non-wholesale market revenues as a threat to ideally competitive markets that should be dealt with through mitigation. The result is a highly complex process that requires new electricity providers to buy out incumbents before they are allowed to enter the market.

Thus, in all three east coast electricity markets, FERC now uses the MOPR to protect some sort of ideal market process and "produce a level of investor confidence that is sufficient to ensure resource adequacy at just and reasonable rates."[254] Doing so, however, has led to a series of highly intrusive administrative interventions in which an administrative body—not market participants—determines the minimum bid amount that generators can submit in auctions for capacity. As the next part shows, this transformation has turned MOPRs into aggressive interventions that counteract state energy policies.

IV. ADMINISTRATIVE PRICING

The Commission's recent orders have drawn criticism from FERC Commissioners, clean energy advocates, and state and federal policymakers.[255] Commissioner Glick, for example, described the December 2019 PJM MOPR Order as "a

249. *See ISO New England, Inc.,* 162 F.E.R.C. ¶ 61,205, at P 1 (2018). In November 2020, FERC denied rehearing while modifying the discussion in the initial CASPR order and reaching the same result. ISO New England Inc., 173 F.E.R.C. ¶ 61,161, at P 2 (2020).

250. 162 F.E.R.C. ¶ 61,205, at P 7.

251. *Id.*

252. *Id.* at P 9.

253. *Id.* at P 22.

254. *Id.* at P 21.

255. *See, e.g.*, *New York State Pub. Serv. Comm'n v. New York Indep. Sys. Operator, Inc.*, 158 F.E.R.C. ¶ 61,137 (2017) (Bay, Comm'r, concurring) ("Despite the best intentions of the Commission, in my view, the MOPR has turned out to be unsound in principle and unworkable in practice."); *New England States Committee*

bailout, plain and simple" and asserted that "[f]rom the beginning, this proceeding has been about two things: Dramatically increasing the price of capacity in PJM and slowing the region's transition to a clean energy future."[256] At least four states have announced that they are considering exiting capacity markets altogether as a result of the 2019 PJM MOPR Order.[257] And industry analysts have estimated that these mitigation rules will cost consumers billions of dollars a year.[258]

Given the stakes of these orders, it is worth considering how, precisely, MOPR reforms have undermined competitive electricity markets. The Commission has justified MOPR reforms as necessary to preserve "market integrity"[259] and protect "investor confidence."[260] In reality, however, FERC's orders do just the opposite. They are restoring elements of the administrative pricing system that used to characterize the electric power system. In doing so, they are leading to higher electricity prices, causing excess capacity to remain in the market, stifling innovation by locking in existing resources when cheaper or cleaner alternatives have also been developed, and impeding state decarbonization programs. Many of these critiques have been discussed in news articles and FERC proceedings. Nonetheless, before considering when, if ever, buyer-side market power mitigation rules are justified, it is first worth describing the many ways MOPRs are undermining principles of competition in regions that have ostensibly restructured the electric power sector.

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on Electricity v. ISO New England Inc., 142 F.E.R.C. ¶ 61,108 (Norris, Comm'r, and Wellinghoff, Chairman, dissenting) ("ISO-NE chose to broadly apply its MOPR to all new resources. The New England States Committee on Electricity (NESCOE) and others have raised significant concerns about whether this broad application of the MOPR will impinge on legitimate state policy goals. In particular, they assert that such broad mitigation will unfairly inhibit state efforts to diversify their fuel mix and procure new renewable resources."); SYLWIA BIALEK & BURCIN UNEL, CAPACITY MARKETS AND EXTERNALITIES: AVOIDING UNNECESSARY AND PROBLEMATIC REFORMS 25 (2018) ("[T]he MOPR-Ex would cause all the standard problems that have been raised related to any MOPR. In particular, it will cause excess capacity because it disregards some of the already existing capacity in the market.").

256. *See* FERC, COMMISSIONER RICHARD GLICK DISSENT REGARDING FERC DIRECTING PJM TO EXPAND MINIMUM OFFER PRICE RULE, https://www.ferc.gov/news-events/news/commissioner-richard-glick-dissent-regarding-ferc-directing-pjm-expand-minimum#.

257. *See* Robert Walton, *New Jersey Looks To Exit PJM Capacity Market, Worried MOPR Will Impede 100% Carbon-Free Goals*, UTIL. DIVE (Mar. 31, 2020), https://www.utilitydive.com/news/new-jersey-looks-to-exit-pjm-capacity-market-worried-the-mopr-will-impede/575160/; SPG GLOB. MKT. INTELLIGENCE, FERC ASKED TO REVISIT MOPR ORDER; CONNECTICUT MAY DECIDE TO PULL OUT OF ISO-NE (Jan. 23, 2020), https://www.spglobal.com/marketintelligence/en/news-insights/trending/k-hm4ghdtgdjafllnhbcbq2.

258. ROB GRAMLICH & MICHAEL GOGGIN, TOO MUCH OF THE WRONG THING: THE NEED FOR CAPACITY MARKET REPLACEMENT OR REFORM, GRID STRATEGIES 10-11 (2019).

259. 163 F.E.R.C. ¶ 61,236, at P 150 (2018).

260. 162 F.E.R.C. ¶ 61,205, at P 21 (2018). The Commission's skepticism of state subsidies stands in stark contrast to its recent endorsement of carbon pricing. Both state subsidies are designed to promote state policy preferences. But in the context of carbon pricing, FERC said that "it is the policy of this Commission to encourage efforts to incorporate a state-determined carbon price in RTO/ISO markets." *See Carbon Pricing in Organized Wholesale Electricity Markets*, 173 F.E.R.C. ¶ 61,062, at P 7 (2020).

A. Excess Capacity

Extending MOPRs to resources that receive state subsidies will force customers to pay for capacity twice.[261] MOPRs are designed to procure a predetermined amount of capacity that is expected to meet a region's expected demand.[262] Capacity markets therefore assume that no other resources will contribute to a region's reliability.

But when other resources enter the market, they provide capacity that supports resource adequacy. Today, resources that do not clear a capacity market auction—either because they were mitigated or for some other reason—will often enter the market anyway, and they will do so for one of two reasons. First, many eastern states have adopted renewable portfolio standards that require LSEs to procure a certain amount of carbon-free electricity.[263] These requirements apply regardless of whether or not zero-carbon resources clear the capacity market auction. Thus, when MOPRs prevent carbon-free generators from clearing the market, they often do not prevent LSEs from purchasing electricity from resources that do not clear capacity auctions. Instead, they force LSEs to pay for the capacity needed to meet regional reliability in the capacity auction, and then again for additional capacity in order to comply with state renewable policies.[264] The result is more capacity than is needed to meet the region's reliability goals.[265]

The second reason that capacity markets procure too much capacity is that they fail to adjust when resources experience price declines in the years between the capacity auction and the capacity commitment period.[266] In the past decade, the average price of lithium-ion batteries has declined eighty-seven percent, from

261. *See, e.g.*, *ISO New England Inc. & New England Power Pool Participants Committee*, 158 F.E.R.C. ¶ 61,138 (2017) (Bay, Comm'r, concurring) ("Instead, the MOPR not only frustrates state policy initiatives, but also likely requires load to pay twice — once through the cost of enacting the state policy itself and then through the capacity market."); *New York Public Service Commission v. New York Independent System Operator, Inc.,* 153 F.E.R.C. ¶ 61,022, at P 61 (2015) (discussing self-supply exemption to buyer-side mitigation rules as a means of "eliminat[ing] the risk of effectively requiring load serving entities to pay twice for capacity in the event that a self-supplied resource does not clear the capacity market."); *ISO New England Inc. and New England Power Pool Participants Committee*, 147 F.E.R.C. ¶ 61,173, at P 65 (2014) (discussing proposed renewable resource exemption from MOPR as a means to "reduce the double payment burden borne by customers who otherwise must pay both for renewable resources to satisfy state renewable resource obligations and for the same amount of capacity to satisfy the ICR, which could have been fulfilled in the first place by renewable resources"); PJM Interconnection, L.L.C., 143 F.E.R.C. ¶ 61,090, at P 69 (discussing proposed self-supply exemption from MOPR as a means to avoid the problem of customers being "required to pay twice" for capacity).

262. *See* NORTH AM. ELEC. REL. CORP., *Methods To Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning* at 3 (Mar. 2011), https://www.nerc.com/files/ivgtf1-2.pdf.

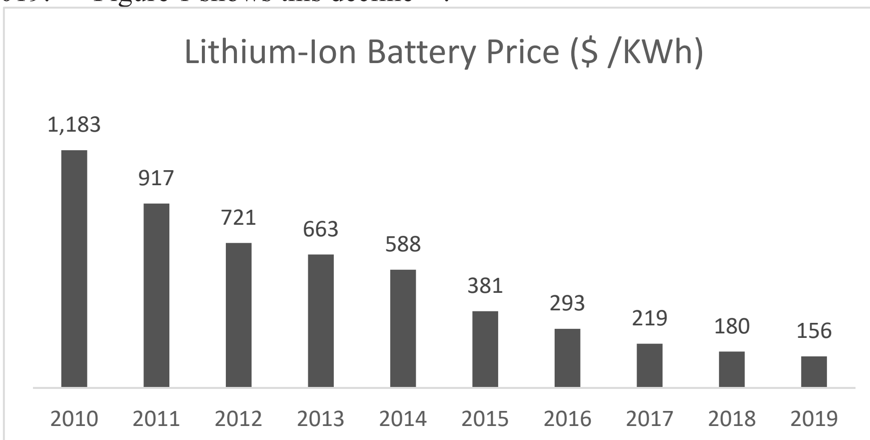
263. *See* NAT'L CONF. OF STATE LEGS., *State Renewable Portfolio Standards and Goals* (Apr. 17, 2020), https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

264. *See* GRAMLICH & GOGGIN, *supra* note 258, at 10-11.

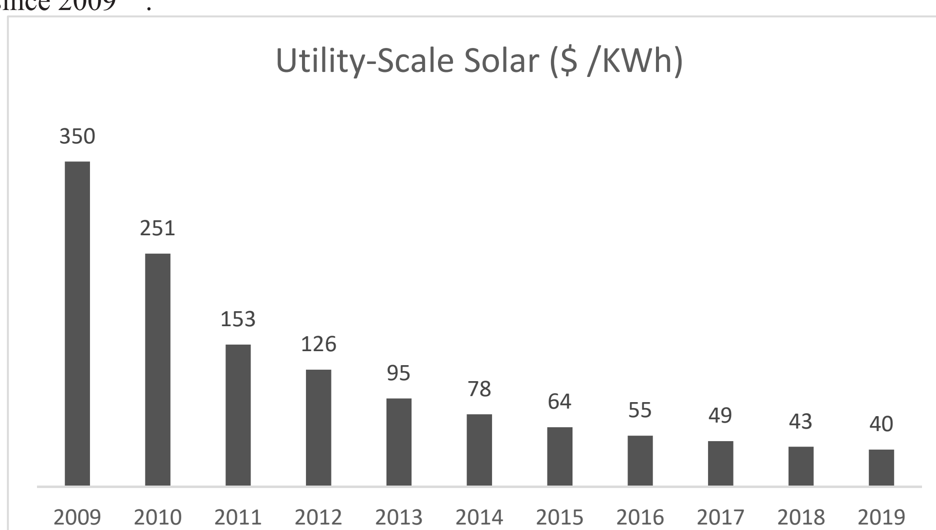
265. *Id.* Municipal utilities and electric cooperatives have long voiced this complaint. *See, e.g.*, Letter from the American Public Power Assoc. & the Nat'l Rural Electr. Coop. Assoc. to FERC (Mar. 5, 2018).

266. The three-year commitment period applies to PJM and ISO-NE, but not to NYISO, which runs its Capability Period Auctions much closer to the commitment period. *See* NYISO Manual 4, Installed Capacity Manual (June 2020), https://www.nyiso.com/documents/20142/2923301/icap_mnl.pdf/234db95c-9a91-66fe-7306-2900ef905338 ("A Capability Period Auction will be conducted no later than thirty (30) days prior to the start of each Capability Period in which Unforced Capacity will be purchased and sold for the entire duration of the Capability Period.").

an average price of $1,183 per kWh in 2010 to an average price of $156 per kWh in 2019.[267] Figure 1 shows this decline[268]:



Solar prices have experienced a similar trend, declining eighty-nine percent over the past decade.[269] Figure 2 shows the average price of utility-scale solar since 2009[270]:



267. *See* Rob Day, *Low-Cost Batteries Are About To Transform Multiple Industries*, FORBES (Dec. 3, 2019), https://www.forbes.com/sites/robday/2019/12/03/low-cost-batteries-are-about-to-transform-multiple-industries/#56ac26f01054

268. *See* Logan Goldie-Scot, *A Behind the Scenes Take on Lithium-Ion Prices*, BLOOMBERG NEF (Mar. 5, 2019), https://about.bnef.com/blog/behind-scenes-take-lithium-ion-battery-prices/.

269. *See* John Weaver, *Solar Price Declines Slowing, Energy Storage in the Money*, PV MAGAZINE (Nov. 8, 2019), https://pv-magazine-usa.com/2019/11/08/sola-price-declines-slowing-energy-storage-in-the-money/#:~:text=Solar%20power's%20utility%20scale%20price,per%20year%20over%20the%20period.

270. *See* LAZARD, 2019 LEVELIZED COST OF ENERGY (Nov. 2019), https://www.lazard.com/media/451086/lazards-levelized-cost-of-energy-version-130-vf.pdf.

When a resource expects its price to decline, the resource may be willing to enter a regional electricity market even if it does not receive revenue from the capacity market. If revenue from energy and ancillary services markets is sufficient for the resource to recover its costs, the resource will enter the market even if it does not receive a capacity payment.

These two phenomena—that state policies will cause resources to enter the market regardless of whether they clear the capacity market, and that some resources can make a profit from energy and ancillary services markets alone—have contributed to the bloated reserve margins that have proven endemic in east coast electricity markets.[271] The three east coast grid operators have set a goal of procuring 13.5% reserve margins, yet NYISO, ISO-NE, and PJM each have reserve margins that hover around thirty percent.[272] In each of PJM's capacity auctions, more resources have offered to sell capacity at the market clearing price than the grid operator determines is necessary for reliability.[273] This is partly due to the fact that capacity markets procure the reserves needed in those regions without recognizing that capacity will enter the market regardless of whether or not it clears a capacity auction.[274] Recall that FERC declared ISO-NE's APR "unjust and unreasonable" for forcing consumers to pay for capacity twice.[275] Yet MOPRs do just that.

B. Overcharge Consumers

MOPRs also force consumers to pay too much for capacity. This happens both because, as discussed above, MOPRs require consumers to pay for capacity they do not need, and also because MOPRs retain costly resources even after those resources are no longer needed to meet demand. Because capacity auctions in PJM and ISO-NE procure capacity three years before the capacity commitment period, they do not adjust to evolving market conditions.[276] Consumers are forced to pay for resources that may have been able to provide the least expensive capacity three years ago, but which today could be replaced with cheaper alternatives.

One industry report found that the cost of procuring excess capacity could add up to $45 billion over the next decade.[277] Although the expected costs vary

271. A reserve margin is the amount of capacity in the region above the region's expected peak demand. A 15% reserve margin means that the region can expect a 15% buffer when demand for electricity is highest. https://www.eia.gov/todayinenergy/detail.php?id=39892#:~:text=The%20anticipated%20reserve%20margin%20considers,the%20summer's%20peak%20hourly%20load.

272. These numbers describe summer reserve margins. *See* NAT'L ELECTR. RELIABILITY CORP., 2020 RELIABILITY ASSESSMENT (June 2020), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2020.pdf.

273. For example, in the August 2010 FCA, when the price floor of $2.951/kW-month was reached, 5,374 MW of excess capacity, over 17%, remained in the auction. *ISO New England Inc.,* 133 F.E.R.C. ¶ 61,230, at P 4 (2010).

274. These are not the only reasons the regions have procured more supply than they need. Another reason is that the administratively determined demand curves are poorly designed. *See* Jacob Mays, *Quasi-Stochastic Electricity Markets* (Dec. 30, 2019), http://www.optimization-online.org/DB_FILE/2019/10/7414.pdf.

275. 135 F.E.R.C. ¶ 61,029, at P 9 (Apr. 13, 2011).

276. Adams James, *Explainer: How capacity markets work*, ENERGY NEWS NETWORK (June 17, 2013), https://energynews.us/2013/06/17/explainer-how-capacity-markets-work/.

277. *See* GRAMLICH & GOGGIN, *supra* note 258, at 28–29 (estimating the cost to consumers in PJM, NYISO, and ISO-NE if the MOPR is "fully imposed on resources that receive state incentives").

based on a variety of factors, the authors found that "[u]nder most scenarios, MOPR will result in billions or tens of billions of dollars in excess costs to electricity consumers across PJM."[278] The analysis estimated that, in the PJM region alone, these costs range from nearly $10 billion[279] to $24 billion[280] over the next nine years, depending on the default bid level that regulators select.

Two related problems are that MOPRs fail to reward marginal efficiencies, and that they do not permit resources to submit below-cost bids even when the supplier has a legitimate reason to do so. In ordinary markets, resources compete to reduce their own costs, secure favorable financing arrangements, hire cheap labor, and make accurate predictions about future market prices. A firm that does any of these things more efficiently than its rivals should be able to capture market share, reduce prices, and pass those savings onto consumers. But by design, MOPRs subject all resources to the same offer floor. As a result, capacity markets do not reward firms that offer superior services or prices than other generators in their same asset class.[281]

And cost differences among generators of the same type can be significant. Some municipal electric cooperatives enjoy tax-exempt status, for example, and are therefore able to secure more favorable financing than private, investor-owned utilities.[282] These entities can often construct new generation less expensively than other firms, yet they are not permitted to reflect those savings in their capacity bids.[283] Disputes about the appropriate offer floor for offshore wind is expected to prevent thousands of megawatts of offshore wind from clearing the ISO-NE and PJM capacity markets despite the fact that these generators would support the region's capacity needs and are expected to be built even if they do not clear the capacity auction.[284]

A related problem is that MOPRs do not allow firms to submit below-cost bids even when they have a legitimate reason to do so. Many resources are willing to sell a product at a loss, especially when they first enter a market, because they

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278. *See* Catherine Morehouse, *PJM MOPR could cost market consumers up to $2.5B annually, report finds,* UTIL. DIVE (May. 19, 2020), https://www.utilitydive.com/news/pjm-mopr-could-cost-market-consumers-up-to-26b-annually-report-finds/578183/. *But see* MONITORING ANALYTICS, POTENTIAL IMPACTS OF THE MOPR ORDER 2 (2020) (concluding that the expanded MOPR is "not expected to have an impact on the clearing prices and auction revenues in PJM's 2022/2023 capacity auction").

279. ROB GRAMLICH & MICHAEL GOGGIN, A MOVING TARGET: AN UPDATE ON THE CONSUMER IMPACTS OF FERC INTERFERENCE WITH STATE POLICIES IN THE PJM REGION, GRID STRATEGIES 3 (2020) (based on the lower default bid level for existing nuclear resources included in PJM's March 2020 compliance filing).

280. *Id.* at 7–8 (based on the higher default bid level for existing nuclear resources in PJM's October 2018 filing).

281. Because firms can compete on these dimensions in energy markets, east coast electricity still leaves some room for competition among generators of the same type.

282. *See* Statement of Patrick E. McCullar on Behalf of the Delaware Municipal Electric Corporation and the American Public Power Association, Nos. ER11-2875-001-022, No. EL11-20-001, at 3 (2011).

283. *See id*.

284. *See* Heather Richards & Arianna Skibell, *FERC Order Could Bar Offshore Wind from U.S. Power Market*, E&E NEWS (May 13, 2020), https://www.eenews.net/stories/1063120381.

believe that their profits will increase alongside their market share. This can happen either because their product enjoys economies of scale, or because production costs will decline as their market share increases.[285]

MOPRs' failure to accommodate legitimate below-cost bidding strategies is especially harmful to emerging resources. In 2019, a storage facility sought to enter the NYISO market but was unable to do so because the market monitor found that the resource's net CONE was above the market clearing price.[286] The resource appealed the market monitor's decision, challenging both the market monitor's calculations, and also arguing that it should be given some discretion to submit below-cost bids because it expected its costs to decline as it gained experience producing lithium-ion batteries.[287] Both the market monitor and FERC disagreed, stating that a generic estimate of the unit's costs that was based on publicly available data—not the resource-specific data provided by the generator—disproved the firm's argument and established that the resource should not enter the PJM market.[288] In another example, discussed in the next Part, FERC found that a NYPA resource should be subject to the MOPR because its *actual* capital costs were lower than the hypothetical, non-subsidized borrowing costs that formed the basis of CONE calculations in the region.[289]

C. *Favors Incumbents*

MOPRs require that east coast grid operators set one price floor for new resources and another for incumbents. In PJM, for example, resources that have previously cleared the capacity auction are subject to a low price floor (known as the "avoidable cost rate," or ACR), and resources that offer to sell capacity at that price are likely to clear.[290] Resources that seek to enter the market, by contrast, cannot bid below their net CONE.[291] In theory, both the ACR and net CONE are designed to measure the revenue a resource needs to earn from a capacity market in order to cover its costs.[292] Yet the ACR is calculated based on the lowest threshold necessary to remain in the market and counts only operating costs—not capital

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285. *See, e.g.*, Keith Head, *Infant Industry Protection in the Steel Rail Industry*, 37 J. INT'L ECON. 141, 141–45 (1994) (describing effect of the steel rail duty on the domestic steel rail industry). State governments may do so as well. New York, for example, has provided significant grants and tax credits to spur semiconductor manufacturing in the state. *See*, COMMITTEE ON COMPETING IN THE 21ST CENTURY: BEST PRACTICES IN STATE AND REGIONAL INNOVATION INITIATIVES, NAT'L RES. COUNCIL OF THE NAT'L ACAD. 156–61 (Charles W. Wessner, ed., 2013).

286. *See ISO New England Inc.,* 170 F.E.R.C. ¶ 61,132 (2020).

287. *Id*. at PP 31-34.

288. *Id.* at PP 44-45, 53.

289. *See Astoria Generating Company L.P. v. New York Independent System Operator, Inc*., 140 F.E.R.C. ¶ 61,189 (2012). Also concerning, is that FERC delayed issuing the rehearing of its ruling for three years before reversing course.

290. *See Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 F.E.R.C. ¶ 61,239, at P 138 (2019). The ACR reflects the annual operating expenses of those resources. *See* Joseph Browning & Ray Pasteris, *RPM Avoidable Cost Rate Development*, MONITORING ANALYTICS, (Nov. 8, 2006), http://www.monitoringanalytics.com/reports/Presentations/2006/20061108-rpm-workshop-avoidable-cost-rate-dev.pdf.

291. 169 F.E.R.C. ¶ 61,239, at P 138 (2019).

292. *See* Adam Keech, *Capacity Market Minimum Offer Price Rule Order*, PJM (Jan. 8, 2020), https://www.pjm.com/-/media/committees-groups/committees/mic/2020/20200108/20200108-item-04a-ferc-order-on-mopr.ashx.

costs or maintenance expenses.[293] Net CONE, by contrast, includes operating costs, capital costs, maintenance costs, and fixed costs.[294] It is understandable that ACR excludes fixed costs. After all, incumbents have already completed construction.[295] But there is no reason to include capital and maintenance costs, which apply equally to new and existing resources, in one calculation and not the other. Nor does it make sense to defer to the "lower threshold" of expected costs when assessing incumbent bids while applying a more exacting standard to new offers.

This unequal treatment creates "a noncompetitive bias in favor of existing resources and against new resources of all types, including new renewables and new gas fired combined cycles."[296] It also means that existing resources are likely to remain in the market even if it is more expensive to operate those resources than it is to replace them.

D. Increase Seller Market Power

MOPRs also entrench *supplier* market power.[297] Electricity markets are already characterized by a high degree of seller concentration, and market monitors have routinely found that supplier market power is endemic in wholesale markets.[298] Even though RTOs and market monitors have adopted a number of rules to ensure the competitiveness of market outcomes,[299] capacity markets have remained vulnerable to the exercise of market power.[300]

MOPRs exacerbate seller market power both (1) by reducing the number of resources that submit competitive bids, and (2) by changing the opportunity cost of withholding capacity. New entry increases competition. Because MOPRs create barriers to new entry, they hamstring investment that would weaken incumbent

293. *Id*. at 7.

294. THE BRATTLE GRP., PJM COST OF NEW ENTRY: COMBUSTION TURBINES AND COMBINED-CYCLE PLANTS WITH JUNE 1, 2022 ONLINE DATE 1 (2018), https://www.pjm.com/~/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-cost-of-new-entry-study.ashx.

295. *Id. Even* that argument is speculative, as resource depreciation schedules generally extend beyond the first capacity commitment period.

296. 169 F.E.R.C. ¶ 61,239, at P 49 (quoting Reply Brief of the Internal Market Monitor for PJM, Nos. EL16-49-000, ER18-1314-000, -001, EL18-178-000 (Nov. 6, 2018) at 4).

297. *See 2011 Quarterly State of the Market Report for PJM*: *January through March*, MONITORING ANALYTICS 134, https://www.monitoringanalytics.com (finding "serious market structure issues, measured by the three pivotal supplier test results, by market shares and by Herfindahl-Hirschman Index (HHI), but no exercise of market power in the PJM Capacity").

298. *See id*.

299. *See PJM Interconnection, L.L.C.,* 154 F.E.R.C. ¶ 61,151, at PP 3–5 (describing PJM's seller-side market power mitigation rules).

300. *See* Reply Comments of the Inst. for Policy Integrity at N.Y Univ. Sch. of Law, Calpine Corporation v. PJM Interconnection, LLC, Docket Nos. EL16-49-000, EL18-178-000 at 14 [hereinafter Institute for Policy Integrity Comments]. MONITORING ANALYTICS, 2018 STATE OF THE MARKET REPORT FOR PJM 251 (2019). In PJM, for example, the Market Monitoring Unit found that the outcome of the 2021/2022 RPM Base Residual Auction "was not competitive as a result of participant behavior which was not competitive, specifically offers which exceeded the competitive level." *Calpine Corporation v. PJM Interconnection, L.L.C., supra* note 6, at P 56.

suppliers' market power.[301] That, in turn, contributes to ongoing concentration of supplier market power.[302]

In addition, by increasing the price of capacity, MOPRs create a windfall for generators that are able to extract monopoly rents by withholding supply. By artificially increasing the price of capacity, FERC has increased the money available to suppliers that exercise market power. The existence of the MOPR means that suppliers can increase their bids "secure in the knowledge that they will still outbid the mitigated offers."[303] If sellers are artificially inflating the price of capacity, then the entry of additional suppliers would drive down electricity prices counteract the price increases caused by supplier-side market power.[304] Eliminating the MOPR would therefore reduce sellers' incentives to manipulate capacity markets and mitigate the harms associated with seller market power abuse.[305]

E. Thwart Decarbonization Policies

MOPRs harm renewables for three reasons. First, resources that seek to enter the market are generally less carbon-intensive than resources that already participate in electricity markets.[306] In providing a windfall to incumbents, MOPRs give carbon emitting resources a competitive advantage that is unavailable to the resources that seek to displace them.

Second, MOPRs prevent clean electricity providers from receiving revenues from capacity markets. Eleven of the fourteen states that participate in PJM have passed renewable portfolios standards.[307] New York, the only state that participates in NYISO, recently passed one of the country's most ambitious clean energy laws.[308] All six states that participate in ISO-NE have passed renewable energy

301. Institute for Policy Integrity Comments, *supra note* 300, at 15. According to the Institute for Policy Integrity, such price decreases would only counteract, not completely nullify, increases caused by supplier-side market power.

302. *Id.*

303. FERC, COMMISSIONER RICHARD GLICK DISSENT REGARDING FERC DIRECTING PJM TO EXPAND MINIMUM OFFER PRICE RULE, https://www.ferc.gov/news-events/news/commissioner-richard-glick-dissent-regarding-ferc-directing-pjm-expand-minimum#.

304. Institute for Policy Integrity Comments, *supra note* 300, at 15. According to the Institute for Policy Integrity, such price decreases would only counteract, not completely nullify, increases caused by supplier-side market power.

305. *Id.*

306. Today, the least cost resources are gas, solar, and wind. The entry of these resources tends to support decarbonization efforts because they displace coal and relatively higher-carbon emitting gas plants. This is not always the case, however, as some storage resources support coal-fired power plants by allowing coal to generate electricity at night, when prices are low, but sell it during the day, when wholesale prices rise. *See* Sonia Aggarwal, et al., *Wholesale Electricity Market Design for Rapid Decarbonization*, ENERGY INNOVATION POLICY & TECH. LLC (June 2019).

307. Emma Nix, *State Energy Policy Scan*, PJM (July 26, 2019), https://www.pjm.com/-/media/committees-groups/task-forces/cpstf/20190726/20190726-item-06a-energy-and-environmental-policy.ashx.

308. *See* NYSERDA, NEW YORK STATE ANNOUNCES PASSAGE OF ACCELERATED RENEWABLE ENERGY GROWTH AND COMMUNITY BENEFIT ACT AS PART OF 2020-2021, https://www.nyserda.ny.gov/About/Newsroom/2020-Announcements/2020-04-03-NEW-York-State-Announces-Passage-Of-Accelerated-Renewable-Energy-Growth-And-Community-Benefit-Act-As-Part-Of-2020-2021-Enacted-State-Budget. FERC recently also rejected as unduly discriminatory NYISO's attempt to accommodate New York's clean energy goals by evaluating Public Policy Resources (energy storage, solar, wind, or other zero-emitting resources) ahead of non-

standards.[309] As discussed in Part I, today capacity markets account for around thirty percent of generator revenues in PJM, ISO-NE, and NYISO.[310] MOPRs often exclude state-subsidized resources from capacity markets. In this way, MOPRs counteract, at least to some extent, the revenues clean sources of electricity receive as subsidies for their low-carbon attributes.

Third, MOPRs give resources that clear the *capacity* market an advantage in *energy* markets. Generators must receive enough revenue to cover their costs. A generator that receives a large capacity payment need not receive as much revenue from energy markets. Granted, generators will not offer to sell electricity in energy markets at a price that is lower than its marginal costs, because doing so would commit it to operating even when it would lose money doing so. But absent significant capacity market payments, generators that operate on the margin may not be able to remain in the market because the profits they receive from energy markets are insufficient to cover their fixed and capital costs. In increasing capacity revenues for fossil fuel generators, capacity markets retain resources that would otherwise retire and likely be replaced by cleaner resources.

F. Administrative Pricing All Over Again

It should by now be clear that MOPRs recreate many of the inefficiencies that are associated with administrative pricing. In restructured electricity markets, investors, at least in theory, receive a return on their investment only if they offer lower-cost services than their competitors. This creates an incentive to reduce costs and develop superior products. But by selecting which resources enter and exit the market, MOPRs resemble the system of utility rate regulation—and its accompanying inefficiencies—despite the fact that this system was supposed to have been rejected when policymakers restructured electricity markets in the 1990s and 2000s. The irony, of course, is that in attempting to promote an ideally competitive market free from outside payments, FERC has imposed an intrusive form of administrative pricing. [311]

And there is one other way that MOPRs recreate the inefficiencies that are generally associated with cost-of-service rate regulation. Cost-of-service rate regulation is circular. The value of an asset depends on the firm's expected future cash flows, yet expected future cash flows are based on a regulator's assessment of the asset's value.[312] MOPRs recreate this circularity in some respects. Regulators calculate price floors by looking at the cost of capital, labor, and land. These

Public Policy Resources when conducting the "Part A" mitigation exemption test. *See* 172 F.E.R.C. ¶ 61,206 at PP 8, 29 (Sept. 4, 2020).

309. ISO NEW ENGLAND, RESOURCE MIX (Jan. 20, 2020), https://www.iso-ne.com/about/key-stats/resource-mix/.

310. MONITORING ANALYTICS, 2019 PJM STATE OF THE MARKET REPORT 16 (2019), https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2019/2019-som-pjm-volume1.pdf; ISO NEW ENGLAND, 2019 ANNUAL MARKETS REPORT 4 (2019), https://www.iso-ne.com/static-assets/documents/2020/05/2019-annual-markets-report.pdf.

311. This is especially ironic in light of a recent PURPA rule, Order No. 872, where FERC endorsed a competitive bidding process to discover avoided capacity costs precisely because it found that administratively-determined avoided cost rates could result in utilities being required to purchase more capacity than necessary. *See* 172 F.E.R.C. ¶ 61,041, at PP 411, 416, 420–24 (2020).

312. *See, e.g.,* Missouri ex rel. Southwestern Bell Tel. Co. v. Public Serv. Comm'n, 262 U.S. 276, 292 (1929) (Brandeis, J., concurring); Helmsley v. Borough of Fort Lee, 78 N.J. 200, 213-14, 394 A.2d 65, 71 (1978).

price floors determine which resources can sell capacity at their preferred price. The administratively-set demand curve, in turn, determines how much revenue generators earn from capacity markets. A generator's cost of capital, however, will depend in large part on a generator's expected revenue. The result is that at least one of the inputs that goes into calculating net CONE is itself partly determined by the administrative decision about how to calculate net CONE for that resource.

V. RESOURCE-SPECIFIC EXEMPTIONS

FERC has at times acknowledged that price mitigation rules resemble administrative pricing,[313] and it has countered that MOPRs do not disfavor new entry because the existence of the resource-specific exemption allows resources to avoid mitigation where their costs are below CONE. The purpose of the resource-specific review, according to FERC, is to "operate[] as a safety valve that helps to avoid over-mitigation of resources that demonstrate that their offers are economic based on a rational estimate of their expected costs and revenues without reliance on out-of-market financial support through State Subsidies."[314] The Commission has explained that "[t]rigger prices form a screen: offers at or above the trigger price are accepted into the FCA with no further review; offers below the trigger price may nevertheless be accepted into the FCA if they are justified with the IMM during the unit-specific review process."[315] Thus, FERC has argued that MOPRs do not unfairly discriminate against new resources because generators can use the resource specific exemption to determine their own costs.

But the resource-specific review process does not appear to allow resources to enter capacity markets on their own terms. Only a small amount of capacity that has entered capacity markets has taken advantage of the resource-specific exemptions. Despite FERC's insistence that resource-specific exemptions permit resources to compete on a level playing field, the resource specific exemption does not offer a viable alternative to mitigation even for resources that can submit competitive bids.

A. The Unit-Specific Exemption

In PJM, a resource seeking to qualify for the resource-specific exemption must submit a request to do so, along with "documentation to support the fixed development, construction, operation, and maintenance costs of the planned generation resource, as well as estimates of offsetting net revenues."[316] The Market Monitoring Unit (MMU) determines whether the offer is acceptable.[317] PJM then performs its own review, and may calculate an acceptable offer based on the data

313. *Id.*

314. 169 F.E.R.C. ¶ 61,239, at P 16. *See also* 135 F.E.R.C. ¶ 61,022, at P 102 ("In response to those who argue that the impact screen should be retained as a check on "over-mitigation," we note that, as discussed later, a new resource whose actual competitive costs are below the offer floor will not be mitigated, as such a resource can verify its actual competitive costs with the IMM.").

315. 142 F.E.R.C. ¶ 61,107, at P 38 (2011).

316. PJM OATT Attachment DD § 5.14(h)(5)(i)-(ii).

317. *Id.* at § 5.14(h)(5)(iv). The MMU must do this at least 90 days prior to the offer period for the auction. *See id.*

and documentation provided by the resource.[318] Finally, the seller must notify both the MMU and PJM of the minimum offer to which it agrees at least sixty days before the auction opens.[319]

ISO-NE has developed a similar process. The market monitor reviews offers that are below the Offer Review Trigger Price for that asset class.[320] Resources can submit documentation that, in theory, should allow the Internal Market Monitor to determine whether an offer is consistent with the resource's costs. This calculation excludes out-of-market revenues.[321] If the Internal Market Monitor determines that the requested offer price is consistent with its own estimate, the resource may submit a bid at the requested price.[322] The Internal Market Monitor may also calculate its own New Resource Offer Floor Price that differs both from the ORTP and the resource's requested price.[323]

NYISO takes a different approach. It compares unit-specific net CONE to the three-year ICAP forecast to determine whether a unit is exempt from mitigation under its "Part B" mitigation exemption test.[324] If the unit-specific net CONE is lower than the three-year ICAP forecast, the unit is exempt from mitigation.[325]

B. *The Unit-Specific Exemption Has Been Used Rarely*

One reason to be skeptical about the unit-specific resource exemption is that only a small amount of capacity has entered the PJM and ISO-NE capacity auctions through these processes.[326] In the 2021/2022 auction, which took place in 2018, PJM granted 4,344.0 MW of the 7,276 ICAP MW of unit-specific exception requests,[327] which is just over 2% of the 192,449.2 capacity that the market monitor found eligible to participate in the auction. In the 2020/2021 BRA, which took place in 2017, no resource requested a unit-specific exception.[328] In the five most recent ISO-NE capacity auctions, the Internal Market Monitor reviewed 460 new supply offers totaling approximately 16,400 MW of qualified capacity.[329] The Internal Market Monitor mitigated approximately 56% of the offers it reviewed, or about 64% of new capacity, resulting in an average increase in offer price of

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318. *Id.*
319. *Id.*
320. ISO-NE, Market Rule 1, § III.A.21.2
321. *Id.* § III.A.21(b).
322. *Id.* § III.A.21(b)(v).
323. *Id.* § III.A.21(b)(vi).
324. *See* NYISO, Services Tariff, § 23.4.5.7.2.
325. *Id.*
326. This fact is not dispositive. It could also indicate that the net CONE calculation is highly precise, and that resources do not take advantage of the unit-specific resource exemption because the net CONE reflects their actual costs. The next subpart suggests this alternative explanation is unconvincing.
327. MONITORING ANALYTICS, 2019 PJM STATE OF THE MARKET REPORT 280, 282 (2019). Monitoring Analytics' report does not state whether the requests granted resulted in offers at the price originally requested by the resource or whether the offers were mitigated upward.
328. *Id.*
329. ISO-NE, 2019 ANNUAL MARKETS REPORT 184. Over 1 million MW of capacity cleared the five most recent capacity auctions. *Id.* at 13.

$3.23/kW-month.[330] For reference, that increase amounts to an additional $3,876,000 per year for a relatively small, 100 MW generator.[331] As in PJM, unit-specific exception requests represent a small portion of total capacity: the 16,400 MW that asked for a different price floor is less than one percent of the 200,000 MW that qualified to participate in the auctions.[332]

C. The Unit-Specific Exemption Has Entrenched Administrative Pricing

The resource-specific exception bears many of the hallmarks of administrative pricing. Publicly available data about the application process, though rare, indicates that the price floor that applies to resources that attempt to use the exemption ultimately reflects the market monitor's assessment of the resource's costs and not the resource's assessment of its own costs.

1. DEMEC

Take, for example, Delaware Municipal Electric Corporation's (DEMEC), which attempted to enter the PJM 2014 base residual auction. PJM's MOPR required DEMEC to submit evidence showing why it should be allowed to offer to sell capacity at less than ninety percent net CONE.[333] PJM calculated that the CONE for this type of resource was $247.52/MW-day. DEMEC's analysis showed that its costs were only "a small fraction" of that figure (approximately forty percent net CONE).[334]

The IMM disagreed. It said that it was "opposed to almost every point" in DEMEC's initial calculation of its cost.[335] In particular, the IMM challenged DEMEC's assessment of its financing costs. The IMM "felt that DEMEC's access to tax-exempt financing as a not-for-profit public power system constituted a "subsidy," even though this subsidy reflected DEMEC's "actual cost of financing."[336] As a result, the IMM increased DEMEC's financing rate by 2%.[337] Because DEMEC felt that this upward adjustment would prevent it from clearing the auction, it appealed the IMM's decision to FERC.[338] Ultimately, the IMM and DEMEC settled on an offer floor that was "substantially higher" than that initially proposed by DEMEC.[339]

330. *Id.* at 185. The price increased from an average submitted price of $2.90/kW-month to the IMM-determined price of $6.13/kW-month. *Id.* Some mitigated resources were also able to elect the then-existing Renewable Technology Resource exemption from ISO-NE's MOPR. *Id.*

331. ($3.23*100,000*12). One MW is 1,000 KW.

332. *See* ISO-NE, FORWARD CAPACITY AUCTION TOTALS FLOW DIAGRAM, https://www.iso-ne.com/static-assets/documents/2018/05/fca-flow-diagram.pdf.

333. Statement of Patrick E. McCullar on Behalf of the Delaware Municipal Electric Corporation and the American Public Power Association, Docket Nos. ER11-2875-001, -022, No. EL11-20-001, at 3 (2011) [hereinafter McCullar Statement].

334. *Id.*

335. *Id.*

336. *Id.*

337. *Id.*

338. McCullar Statement, *supra* note 333.

339. *Id.*

The unit-specific review process thus resulted not in an offer floor that reflected DEMEC's assessment of its own costs, but rather an administrative compromise that landed somewhere between DEMEC's cost-based calculation and the market monitor's own estimate.[340]

2. Able Grid

This problem is not limited to PJM. In 2019, a company called Able Grid sought to use lithium-ion batteries to support grid reliability in New England. Able Grid found itself caught in a battle between ISO-NE's two market monitors (ISO-NE has both an "internal" and an "external" market monitor). In its informational filing for the 2023-2024 Capacity Commitment Period, ISO-NE included details about which resources would be allowed to participate in the capacity auction and which would not.[341] The External Market Monitor claimed that the Internal Market Monitor over-mitigated energy storage resources, and that it did so because it relied on unreasonably low estimates of the revenue those resources would earn in energy and ancillary services.[342] The External Market Monitor asked FERC to direct the Internal Market Monitor to re-estimate the net revenues, and to use the External Market Monitor's methodology.[343] Able Grid, which had proposed two battery storage projects that were rejected under the Internal Market Monitor's methodology, intervened, claiming that although it had provided documentation to support its proposed offer floor prices, the IMM denied its submissions and instead substituted a different offer floor.[344] Like the External Market Monitor, Able Grid argued that the IMM relied on unreasonably low estimates about future energy market revenues.[345]

Able Grid also claimed that it had provided documentation that countered the IMM's analysis of its fixed and capital costs.[346] But according to the IMM, Able Grid's evidence was irrelevant, because the IMM instead relied on publicly available data that analyzed projects on a generic basis.[347] Able Grid also stated that the IMM relied on a FERC-approved cost of new entry study to calculate Able Grid's cost of capital, rather than the calculations that Able Grid provided.[348] In other words, disagreement about future energy and ancillary services revenues, and about whether it is more appropriate to use information that a generator sub-

340. This process resembles a phenomenon Anthony Casey and Julia Simon-Kerr identified as occurring when judges value assets. Casey and Simon Kerr find that, rather than rely on accurate valuation methods, judges often "eschew expertise and valuations grounded in research and mathematical models in favor of the middle ground." Anthony J. Casey & Julia Simon-Kerr, *A Simple Theory of Complex Valuation*, 113 MICH. L. REV. 1176, 1177 (2016).

341. 170 F.E.R.C. ¶ 61,132, at PP 1-10 (2020).

342. *Id.* at PP 19–24.

343. *Id.* at P 24.

344. *Id.* at P 27.

345. *Id.* at P 34.

346. 170 F.E.R.C. ¶ 61,132, at P 29.

347. *Id.* at P 31. Further, Able Grid argued that the IMM used an overly conservative measure of salvage value.

348. *Id.* at P 33. The IMM argued that it was justified in rejecting Able Grid's requested offer floor prices because the values of those prices were driven by unreasonably high estimates of net energy and ancillary services revenue. *Id.* at P 44.

mits about the costs of its project or generic estimates about the costs of constructing generators of that type, was the reason Able Grid was unable to offer to sell capacity at the price it felt was justified.

As with DEMEC, FERC rejected Abel Grid's argument, agreeing with the IMM that Able Grid had not provided sufficient support for its estimates of total investment costs, salvage value, and capital costs. FERC also found that the IMM's estimate of net revenues was reasonable.[349] In particular, the Commission said that it was reasonable for the IMM to rely on a generic estimate of net revenues and other publicly available data, rather than resource-specific estimates.[350]

3. Astoria Energy II

Astoria Energy provides perhaps the most dramatic example of the extent to which the unit specific exemption is another form of administrative pricing. Astoria owned a 575 MW generating facility. In July 2011, NYISO permitted Astoria to offer into the July 2011 capacity auction without being subject to the offer floor.[351] At the time, a resource would not be subject to mitigation if the average capacity market prices across six capability periods was projected to be higher than the resource's net CONE.[352] In making the exemption determination, NYISO used Astoria II's actual cost of capital, which was based on favorable financing terms that resulted from a twenty-year power purchase agreement with the New York Power Authority (NYPA) and NYPA's good credit rating as a state-chartered entity. [353]

Two generators challenged this determination.[354] The complainants argued that the financing terms available to Astoria as the result of the power purchase agreement "were not the result of legitimate competitive advantage but rather are attributable to out-of-market payments."[355] They further alleged that the power purchase agreement was the result of discriminatory contracting process because it was limited only to new resources.[356] The generators felt that NYISO should have instead used the cost of capital figures for a proxy unit.[357]

FERC agreed.[358] It found that the use of actual cost of capital was inappropriate because the power purchase agreement was an out-of-market payment available only to Astoria II that allowed it to attract capital on more favorable terms "inconsistent with a competitive offer."[359] FERC also found that the power purchase agreement was discriminatory despite the fact that the request for proposals that culminated with the power purchase agreement had been open and transparent.[360] Citing a previous MOPR order, FERC determined that the financing costs

349. *Id.* at PP 51, 53.
350. *Id.*
351. *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, 140 F.E.R.C. ¶ 61,189, at P 37 (2012).
352. *Id.* at PP 3–6.
353. *Id.* at PP 126–27.
354. *Id.* at P 11.
355. *Id.* at P 123.
356. 140 F.E.R.C. ¶ 61,189, at P 123.
357. *Id.* at P 124.
358. *Id.* at P 134.
359. *Id.* at P 135.
360. *Id.*

associated with the power purchase agreement constituted an "irregular or anomalous" cost advantage "not in the ordinary course of business."[361] Accordingly, FERC required NYISO to ignore Astoria II's actual costs in favor of a proxy reference unit's costs.[362]

No one disputed that Astoria's actual costs fell below CONE, but FERC still denied, at least initially, Astoria's exemption request.[363] The unit-specific exemption thus as a practical matter seems to involve a great deal of administrative oversight and, even generating units whose costs are below the CONE have often failed to qualify for the exemption. The unit-specific exemption therefore does present a meaningful alternative to the MOPR, but rather another layer of administrative pricing for resources seeking to enter capacity markets at a price below the MOPR offer floors.

VI. When, If Ever, Are MOPRs Justified

Given the problems MOPRs generate, it is worth considering if price mitigation is ever justified. As Part I showed, FERC has insisted that MOPRs are needed to prevent price suppression. The central question this Article takes up is when price suppression harms wholesale electricity markets. This Part explains that price suppression is problematic when it is a means of exercising market power. Below-cost bids submitted by net buyers can create a market for lemons in which independent power producers are driven out of business. Price suppression is not problematic, however, when it is a consequence of state subsidies or of competitive bidding strategies.

A. State Subsides Do Not Undermine Capacity Markets

By itself, price suppression poses no harm to wholesale electricity markets. Grid operators aim to procure an amount of capacity that will maintain resource adequacy in their regions. The way they do this in the east coast electricity markets is to construct a downward sloping demand curve that provides for descending prices and corresponding increases in quantity supplied. This demand curve is an administrative construct and does not necessarily correspond to consumers' willingness to pay or an actual demand curve, though it is intended to approximate consumers' willingness to pay for various quantities of capacity.[364] The downward sloping demand curve is designed to estimate the demand for capacity resources

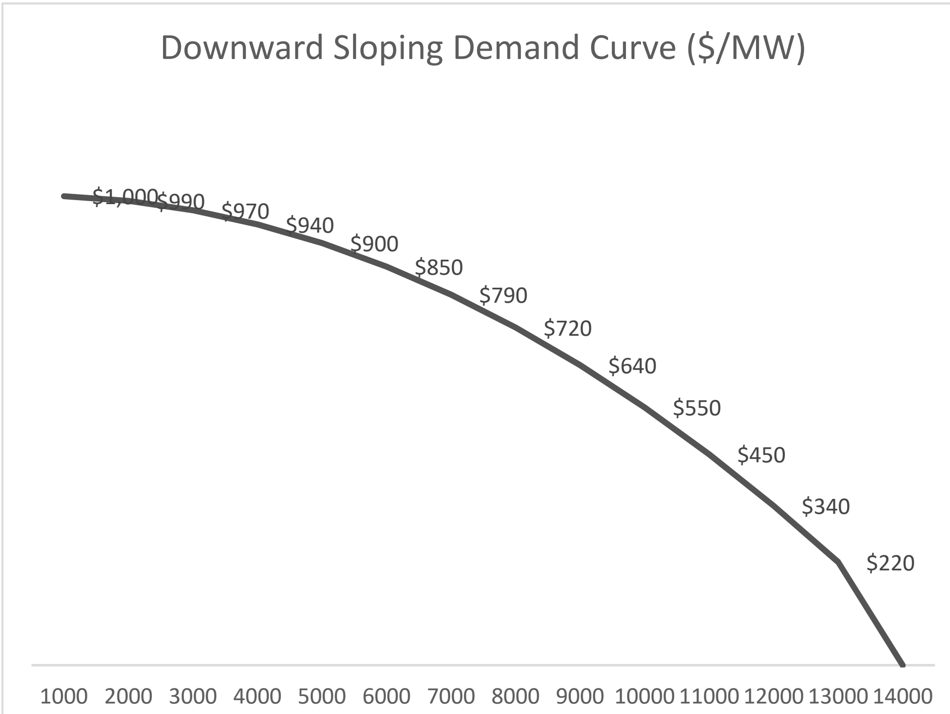
361. 140 F.E.R.C. ¶ 61,189, at P 135 (citing *PJM Power Providers Grp. v. PJM Interconnection, L.L.C.*, 137 F.E.R.C. ¶ 61,145, at P 245 (2011)).

362. *Id.* FERC ultimately reversed course in 2015 after a lengthy administrative process, finding that the agreement was not discriminatory and thus that Astoria could be exempted based on its own cost of capital. *Astoria Generating Co. v. New York Indep. Sys. Operator, Inc.*, 151 F.E.R.C. ¶ 61,044 (2015). Even so, FERC suggested that ISOs should be on the look-out for circumstances that would merit replacing actual costs with proxy costs.

363. *Id*. at P 78.

364. It is also worth mentioning that capacity market rules themselves favor certain resources and thus fail to create the type of level playing field that FERC claims to be protecting when it mitigates generator bids. *See* Jacob Mays, David Morton, & Richard O'Neill, *Asymmetric Risk and Fuel Neutrality in Capacity Markets*, https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3330932.

over a range of different prices.[365] Figure 3 models a downward-sloping demand curve for capacity[366]:



The downward sloping demand curve will result in more capacity entering the market when price decreases and less capacity when price increases. In the example above, if the price of capacity is $1,000 per MW, it will procure only 1000 MW of capacity. If the price of capacity is $220 per MW, it will procure 13,000 MW.

Thus, rather than lead to reliability problems, state subsidies actually support resource adequacy. State subsidies allow resources to rely on non-wholesale market revenues to cover some of their costs. They therefore drive the price of capacity down. In doing so, they shift the supply curve to the right, which causes supply to intersect demand at a lower price point. Imagine if, in the Figure above, the supply curve would intersect with the demand curve at $850 when the grid operator mitigates state-subsidized bids and $790 when it allows state-subsidized resources to participate in the auction. With mitigation, the capacity auction would procure 6,000 MW of capacity. Without mitigation, it would procure 7,000 MW

365. *See* ISO-NE, Downward Sloping Demand Curve, https://www.iso-ne.com/committees/key-projects/implemented/fcm-sloped-demand-curve. Grid operators today do not agree to procure a fixed amount of capacity regardless of price, though ISO-NE actually used a vertical demand curve from 2006 to 2010.

366. The grid operators' actual demand curves are slightly more complicated than the stylized example above. *See* ISO-NE, Regulatory Tariff, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_3/mr1_sec_13_14.pdf; PJM, VRR Curve, https://www.pjm.com/-/media/committees-groups/committees/mic/20180425-special/20180425-pjm-2018-variable-resource-requirement-curve-study.ashx.

of capacity. In other words, the use of a downward-sloping demand curve means that state subsidies will result in more capacity clearing the market and at a lower price.[367]

B. Buyer Market Power Can Harm Capacity Markets

Buyer market power, by contrast, can, at least in theory, harm wholesale electricity markets. But while FERC has asserted that buyer market power is a problem, it has never actually explained how market manipulation by net buyers distorts wholesale electricity markets. The problem with buyer market power in capacity markets is that it threatens to prevent independent power producers from entering the market. The issue is not simply that net buyers have an incentive to suppress capacity market prices. It is that they have an incentive to do so indefinitely. A net buyer will have an incentive to suppress capacity prices whenever competitors are in the market, because the firm may be able to raise prices and extract monopoly rents when its competitors exit the market. In fact, because even the threat of predation can deter market entry, net buyers will be less inclined to enter the market if they are concerned about predation.

Price suppression can benefit net buyers for two reasons. First, as explained in Part I, by suppressing wholesale market prices, net buyers can reduce the price they pay for capacity when competitors are in the market. Second, by capturing market share that would otherwise belong to independent power producers, net buyers can engage in predatory pricing. In setting prices below a competitive level, market manipulation could drive independent power producers to exit the market. And, if independent power producers know that they are competing against firms that have an incentive to suppress capacity market prices below competitive levels, they might fear that such market manipulation will continue to prevent capacity market prices from ever rising high enough to allow independent generators to cover their costs. This may drive independent firms to leave the market and deter prospective competitors from entering. The existence of an administratively-constructed demand curve will lead the region to continue to procure sufficient capacity, but only from net buyers that are able to benefit from extracting monopoly rents once their predatory pricing has driven their competitors out of the market.[368]

If buyers' anticompetitive conduct prevents independent power producers from entering the market, the only supply that will be left would be provided by firms that have agreed to sell capacity at a loss.[369] Market manipulation could drive independent power producers—the firms whose profits come from sales of electricity and that bring competition to electricity markets—out of the market. Ultimately, this could harm net buyers if they are forced to sell capacity at a loss.

367. One might argue that a problem with state subsidies is that they lead to too much supply, not too little, because they cause the supply curve to shift to the right and, in that way, procure more supply than is needed. One response to that is that the downward sloping demand curve reflects the value of capacity at different price points, and so the market should procure more capacity when price decreases. Moreover, even if this is problematic, MOPRs exacerbate—rather than mitigate—this issue by further bloating reserve margins. *See supra* Part II.C.

368. This is a variant on the Market for Lemons. *See,* Akerlof, *supra* note 20, at 488.

369. It will be problematic for these firms if they are required to continue to sell capacity at a loss. It would benefit them if they are then able to raise prices.

While net buyers benefit from predation when the price suppression reduces the amount that they must pay for capacity, it is possible that they would be forced to sell capacity at a loss if they successfully drive out their competitors. Presumably, though, net buyers expect to benefit from predatory pricing by raising prices after driving out their competitors. If the threat of predatory pricing drives out competitors, utilities may be able to extract monopoly rents from selling electricity. Thus, the justification for mitigation is not that a policy or bidding strategy suppresses wholesale prices, but that it does so in a manner that prevents resources from competing along price. If such behavior leads to vertical reintegration, it really would undermine competitive electricity markets.

There is at least some reason to be concerned that some net buyers of electricity are well-positioned to successfully predate. Ordinarily, courts are skeptical of predation claims.[370] Successful predation is difficult to execute. It generally requires that firms with market power sell a product at a loss. The period of losses naturally deters predatory pricing, because firms are reluctant to incur certain losses for the uncertain possibility of a future monopoly, especially since there is a risk that rivals will reenter the market once the firm raises prices back to a profitable level. In addition, it is extremely difficult to distinguish predatory pricing from other benign motivations for price cuts. Recognizing that firms are reluctant to sell at a loss[371] and that over-enforcement would deter efficient price cuts,[372] courts have created a high bar for successful predation claims.

But this logic does not apply to net buyers of capacity. As explained in Part II, net buyers in electric power markets actually profit while engaging in predatory pricing. While their generators incur a loss, net buyers recover those losses by reducing the price they pay to purchase capacity. As a result, unlike net buyers in other markets, price cuts do not erode the buyers' profits while it is predating. There is therefore reason to think that net buyers might engage in price cuts not simply because they can drive rivals out of the market (the standard explanation of predation), but also because predatory pricing is profitable even when the firm is engaged in predatory pricing. In other words, because net buyers of electricity benefit from price suppression, they have a strong additional incentive to predate.[373]

This is the most generous interpretation of FERC's MOPR, however, and it is at best theoretical. FERC does not appear to have offered any evidence that net buyers are purposefully manipulating capacity prices. Nor has the Commission explained why ordinary enforcement actions would fail to deter this type of

370. Brooke Grp. Ltd. v. Brown & Williamson Tobacco Corp., 509 U.S. 209 (1993).

371. *Id.* (quoting Matsushita Elec. Indus. Co. v. Zenith Radio Corp., 475 U.S. 574, 589 (1986) to the effect that "predatory pricing schemes are rarely tried, and even more rarely successful"). *See also* Aaron S. Edlin, *Stopping Above-Cost Predatory Pricing*, 111 YALE L.J. 941 (2002).

372. Barry Wright Corp. v. ITT Grinnell Corp., 724 F.2d 227 (1983) ("The antitrust laws very rarely reject such beneficial 'birds in hand' for the sake of more speculative (future lowprice) 'birds in the bush.'") (Breyer, J.).

373. In fact, vertically integrated utilities that can recover some of their generation costs in state ratemaking proceedings may have an additional incentive to submit below-cost bids. *See Fuel Adjustment Clauses & Other Cost Trackers*, ELEC. CONSUMERS RES. COUNCIL, https://Elcon.Org/Fuel-Adjustment-Clauses-cost-trackers/ ("A fuel adjustment clause (FAC) is a tariff provision which permits a change in rates to occur as a result of a change in the cost of fuel or a portion of purchased power expenses. These changes occur without the utility filing a formal rate case.").

behavior more directly. As a result, while there may be some reason to worry that net buyers are abusing their market power, it is not at all clear that MOPRs are an appropriate remedy.

In any event, none of this logic applies to resources that receive state subsidies. Unlike capacity offered by net buyers, subsidized resources benefit financially when capacity prices increase. Unlike net buyers, state-subsidized resources have no incentive to submit below-cost bids to manipulate capacity markets. Generators that receive a state subsidy will, like all resources, bid whatever price allows them to recover their costs. When a state subsidizes a resource, it is presumably compensating the generator for providing something of societal value, such as carbon-free electricity, and the payment allows the subsidized resource to operate even if it receives less revenue from wholesale markets.

But such subsidies do not prevent the capacity market from working. The capacity market is an administrative construct. When capacity is needed, the price of capacity will increase. This is axiomatic. The market is designed such that the capacity price increases whenever there is a capacity shortfall. This price increase will induce market entry whenever there are not enough resources available to meet expected peak demand.

There is therefore no reason for independent power producers to be concerned that the participation of state-subsidized resources will lead to the collapse of competition in capacity markets. A state subsidy reduces the price of capacity, but subsidized resources remain senstitive to the price signals generated by the wholesale market in which they operate, and the price of capacity will still increase whenever there is a capacity shortfall. Thus, resources that provide the lowest-cost service needed by the grid will clear the capacity auction. While subsidies may make some resources less likely to clear, they do so only because a state has agreed to accept some of the resource's costs.[374]

To the extent that buyer market power is a problem in east coast electricity markets, policymakers should target the source of the problem. This likely involves stronger ex post enforcement of market power abuses. Perhaps, also, regulators should consider requiring large transmission utilities to divest themselves of their generation assets.[375] Moreover, while contracts for differences do allow distribution companies to hedge against price volatility, so too do options and futures.[376] Since other hedging strategies are available to LSEs, FERC could prohibit

374. The one exception is a contract-for-differences which, as discussed in Part I.B, allows the state to act as a buyer. When a state instructs a utility to procure a certain type of resource through a contract for differences, it forces other ratepayers in other states to bear as much of the cost of the subsidy as possible. By contrast, rather than offload costs onto other states and market participants, ordinary state subsidies increase the amount of capacity that enters a market.

375. Full divestiture, however, could only be accomplished either if Congress granted FERC additional authority, or if states intervened more aggressively than they have in the past. *See* Matthew Christiansen & Joshua Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360 (2021). As noted, our concern is with large distribution utilities that are in a position to exercise market power, not with small government utilities or rural co-ops.

376. The Intercontinental Exchange lists over a hundred futures and options products that would allow LSEs to hedge against price volatility in capacity markets. *See e.g.*, https://www.theice.com/products/Futures-Options/Energy/Electricity.

LSEs that are in a position to exercise market power from entering into the type of contract that has left capacity markets vulnerable to market power abuses.

The main point, though, is that whatever economies of scale follow from vertically integrating generation and transmission does not justify the degree of administrative pricing that now characterizes east coast electricity markets—especially when those interventions continue to be justified as necessary to preserve competition. To date, FERC has only identified two situations in which capacity markets are vulnerable to buyer market power abuses: when net buyers build their own capacity, and when states or net buyers enter a contract for differences that gives the generator an incentive to offer to sell capacity for $0. Absent evidence that capacity markets are vulnerable to other types of buyer market power abuses, FERC should limit MOPRs to these two situations, and even then, the Commission should not impose administrative pricing until it has proof that such market power abuses are actually occurring—evidence that the Commission did not provide even when MOPRs ostensibly targeted market power abuses.

VII. CONCLUSION

For over a decade, FERC has used MOPRs to protect competitive electricity markets. It has justified these interventions by claiming that MOPRs enable perfectly competitive markets that match physical power flows to system needs. But as this Article has shown, the problem FERC diagnosed in the mid-2000s is a market power problem—not a price suppression problem. While FERC has lost sight of this original purpose, there does not appear to be any plausible reason to mitigate resources that do not exercise market power.

In expanding mitigation to resources that do not exercise market power, MOPRs have the opposite of their intended effect. They have led to a system of administrative pricing that has increased prices, contributed to bloated reserve margins, and hamstrung state de-carbonization efforts. FERC has also long claimed to be technology-neutral—that it breaks down barriers to entry and makes sure that resources are able to compete on a level playing field.[377] Yet, MOPRs treat incumbent merchant generators more favorably than other suppliers.

In order to promote competitive electricity markets, FERC should adopt a lighter regulatory touch. Rather than dictate the terms of electricity market participation, it should intervene only when there is clear evidence of market manipulation or market power abuse. Even then, aggressive enforcement would be preferable to administrative pricing. A better approach to buyer market power would prohibit vertical integration between distribution and generation facilities. If regulators are unable to do this, either because of jurisdictional limitations or political will, they should only mitigate bids when the bidder has the incentive and ability to exercise monopsony power.

377. *See e.g.*, *PJM Interconnection, L.L.C.*, 167 F.E.R.C. ¶ 61,058, at P 59 (2019) (endorsing "a technology-neutral approach ensures that no resource that can perform the same service is unnecessarily excluded from fast-start pricing treatment").

REDUCING CONFLICT AND RISK: WHY PARTIES BENEFIT FROM USING ENUMERATED ADJUSTMENT CLAUSES IN ENERGY CONSTRUCTION AND SERVICES AGREEMENTS

*S. Scott Gaille**

Synopsis: As the United States transitions to more renewable energy sources, spending under energy construction and services agreements is expected to double over the next decade. Each of these agreements contains an adjustment clause, which determines under what circumstances contractors are entitled to be paid more or receive additional time to complete their work. There are two principal types of adjustment clauses: (a) discretionary adjustment clauses, which do not allocate specific risks at the time of contract execution, largely leaving the determination to the parties (after a risk materializes) and (b) enumerated adjustment clauses, which expressly list certain risks and establish rules regarding when the contractor is entitled (or not) to adjustments for each such risk. Types of enumerated adjustments include: (i) owner changes; (ii) differing site conditions; (iii) owner-caused delay; (iv) owner's suspension of work; (v) force majeure; (vi) adverse weather; (vii) protester-caused delays; and (viii) effects of widespread disease. While contractors generally prefer discretionary clauses (and owners, enumerated clauses), this article concludes that the perceived benefits for contractors of discretionary clauses are outweighed by their uncertainties, inefficiencies, and other costs. It is better to agree *ex ante* on the rules for adjustments in enumerated clauses, which results in more complete agreements.

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I. INTRODUCTION

Construction and services agreements are living, dynamic documents. The price and completion date agreed at signing are just the starting points. Both may be adjusted dozens of times over the course of the work. What the owner ends up paying for a project can be substantially higher, and the completion deadline much later, than initially agreed.

As such, negotiating a construction or services agreement entails considering when the contractor should be paid more (or less) compensation and/or should have its schedule to complete the work lengthened (or shortened). Such variances are referred to as price and time adjustments, and collectively as adjustment clauses. The adjustment clause is arguably the most important term in a construction or services agreement. It can make or break an owner's budget. It can enrich or bankrupt a contractor.

This means that the first question every owner or contractor should ask is:

What kind of adjustment clause is in my contract?

Adjustment clauses generally fall into one of two categories:

- *Discretionary Adjustment Clauses.* Discretionary adjustment clauses set forth a general, often vague standard, such as "changed circumstances." The contractor may seek an adjustment for virtually any type of change it can think of, but the owner has considerable discretion to accept or reject the adjustment request.
- *Enumerated Adjustment Clauses.* Enumerated adjustment clauses list each and every circumstance for which the contractor is entitled to an adjustment (and the contractor is not entitled to an adjustment for any circumstance that is not listed). While the contractor may only seek an adjustment for the listed circumstances, the owner has little discretion to reject valid claims.[1]

While contractors tend to prefer the discretionary adjustment clause, owners prefer the enumerated approach. This article takes a third position, maintaining that the certainty provided by an enumerated adjustment clause creates efficiencies

1. Parties also can negotiate hybrid adjustment clauses. For example, the overall contract could provide that adjustments are only allowed for an enumerated list of circumstances, but then, allow for more discretion within the definition(s) of one or more of the enumerated grounds.

that are beneficial to both owners and contractors. A properly drafted enumerated adjustment clause should be a win-win.

How important are adjustment clauses to the energy industry? North American oil and gas infrastructure construction is forecasted to continue at a pace of more than $44 billion per year as new pipelines are built and aging lines and related facilities are maintained or replaced.[2] Additional layers of construction and services spending also will be required by renewable energy sources.

The electricity generated by wind turbines in the United States is expected to nearly double by 2030,[3] from 113 GW to 224 GW (there are currently around 65,548 turbines operating today[4]). If the average installed cost for wind power is $1,400 per kW,[5] that equates to over $15 billion annually over the next decade.[6] Once constructed, wind projects require an average of $70,000 per turbine per year in operating and maintenance (O&M) costs[7]—a further $4.5 billion per year at present levels[8] and approximately $9 billion per year by 2030.[9] A wind turbine lasts approximately twenty years,[10] which means that one-twentieth of them will need to be replaced annually, likely requiring another $20 billion per year by 2030 just to maintain existing capacity.[11]

Construction of solar electric generating facilities also continues to rapidly increase. In 2019, "solar electric generating systems accounted for 40% of all new electric generating capacity in the United States . . . its highest share ever."[12] Solar

2. INTERSTATE NAT. GAS ASS'N OF AM. FOUND., NORTH AMERICAN MIDSTREAM INFRASTRUCTURE THROUGH 2035 2 (June 18, 2018), https://www.ingaa.org/File.aspx?id=34703. These projections were published prior to the global COVID-19 pandemic and may be adversely impacted by the economic fallout resulting from that event.

3. U.S. DEP'T OF ENERGY, MAP: PROJECTED GROWTH OF THE WIND INDUSTRY FROM NOW UNTIL 2050, https://www.energy.gov/maps/map-projected-growth-wind-industry-now-until-2050 (last visited Apr. 1, 2021).

4. U.S. GEOLOGICAL SURVEY, THE U.S. WIND TURBINE DATABASE, https://eerscmap.usgs.gov/uswtdb/ (last visited Apr. 1, 2021).

5. The average rated capacity of newly installed wind turbines in the United States was 2.43 MW in 2018. U.S. DEP'T OF ENERGY, 2018 WIND TECHNOLOGIES MARKET REPORT at viii, https://www.energy.gov/sites/prod/files/2019/08/f65/2018 [hereinafter 2018 WIND TECHNOLOGIES MARKET REPORT]. The capacity weighted average installed wind project cost in 2018 was $1.470/kW. *Id.* at x. This translates to an average installed project cost of $3,572,100 ($1,470 per kW * 2,430 kW).

6. ($1,400 per kW) * (111,000,000 kW of additional generation by 2030) / (10 years) = $15,540,000,000 per year.

7. The average O&M cost of wind projects built since 2010 was $29/kW of rated capacity per year, or $70,470 per year for the average wind turbine with a rating of 2.43 MW. 2018 WIND TECHNOLOGIES MARKET REPORT, *supra* note 5, at 55.

8. 65,548 wind turbines * $70,470 per year.

9. 131,096 wind turbines * $70,470 per year.

10. Christian Schumacher & Florian Weber, *How to Extend the Lifetime of Wind Turbines*, RENEWABLE ENERGY WORLD (Sept. 20, 2019), https://www.renewableenergyworld.com/2019/09/20/how-to-extend-the-lifetime-of-wind-turbines.

11. If there are 131,096 turbines, with 5% being replaced annually at a cost of $3,572,100 a piece, that equates to $23,414,401,080 billion in replacement expenditures per year.

12. Georgina Owino-Trice and Shabad Puri, *The Eye of the Beholder: An Introduction to Key Clauses in Solar Engineering, Procurement and Construction Contracts*, 44 SECTION REPORT OF THE OIL, GAS & ENERGY

power generation is expected to approximately double by 2030, with additions of about 10 gigawatts, costing approximately $1 billion per year.[13]

All of these expenditures will be made pursuant to construction and services agreements containing adjustment clauses.

II. THE VALUE OF CONTRACT COMPLETENESS

Contractual uncertainty is inefficient and expensive.[14] What happens when the contract is unclear about whether the contractor receives an adjustment for a given event? The contractor usually will increase its prices in the original contract by adding contingency dollars. Contingency dollars are amounts added to the price of construction (or services) to cover the possibility that the contractor may not receive additional payments for a potential event.

At the bidding stage, such contingency creates problems for both contractors and owners. Contractors may struggle to quantify this risk of uncertainty. Owners may have difficulty unbundling and understanding how different bidders' pricing was impacted. The contract may be won or lost on the basis of different contractors' (more subjective) perceptions of the risk that an adjustment will be denied—instead of the (more objective) estimated cost of construction.

The inefficacies of adjustment uncertainty also affect the overall economics of a project. The owner effectively pays insurance dollars to cover the uncertainty faced by the contractor (i.e., being uncompensated for occurrence of a risk). If the risk never materializes, the owner has effectively paid (for a portion of something) that never happened—which results in a windfall for the contractor. If the risk does materialize, the amount of the contingency may be less than the actual costs incurred by the contractor, potentially leading to a claim for the difference.

While no contract is perfect, each should be reasonably "complete." By complete, I mean that the contract has expressly and clearly allocated the risk for known unknowns. "Known unknown" risks are those that the parties are aware of because they occur regularly in construction and services projects. However, the parties do not know whether a given risk will materialize for a particular project—and if it does, what the cost and schedule impact will be. As one commentator observed, "construction projects, by their nature, are plagued by unforeseen circumstances. Construction contract documents generally reflect a conscious effort

RESOURCES SECTION OF THE STATE BAR OF TEXAS 54 (Sept. 2020) (citing *Solar Accounts for 40% of U.S. Electric Generating Capacity Additions in 2019, Adds 13.3 GW*, SOLAR ENERGY INDUS. ASS'N (Mar. 17, 2020), https://www.seia.org/news/solar-accounts-40-us-electric-generating-capacity-additions-2019-adds-133-gw).

13. U.S. DEP'T OF ENERGY, WIND AND SOLAR DATA AND PROJECTIONS FROM THE U.S. ENERGY INFORMATION ADMINISTRATION: PAST PERFORMANCE AND ONGOING ENHANCEMENTS 20 (Mar. 2016), https://www.eia.gov/outlooks/aeo/supplement/renewable/pdf/projections.pdf.

14. Walter J. Andrews et. al., *A "Flood of Uncertainty": Contractual Erosion in the Wake of Hurricane Katrina and the Eastern District of Louisiana's Ruling in In re Katrina Canal Breaches Consolidated Litigation,* 81 TUL. L. REV. 1277, 1301 (2007) ("Above all, the written contract has allowed contracting parties to know, well after the date of their agreement, precisely what they agreed to do . . . The *Canal Breaches Litigation* decision . . . will alter commerce as we know it today, making life more expensive, less efficient, and considerably less predictable.").

to anticipate the unexpected and to allocate the risk so the project can go forward."[15] Express and clear allocation of such risks—not mere mention of or haphazard reference to the risk—is critical because "recovery is dependent upon the precise terminology used" in the contract.[16]

By addressing the known unknowns, contract completeness affords a number of benefits to both parties, including:

- *Meeting of the Minds.* Negotiation of detailed agreements prevents issues from being swept under the rug, thereby ensuring that the parties have a meeting of the minds regarding who bears which risk.
- *Predictability.* When a risk does occur, the parties know who is responsible for it. This means that only one party is required to take financial steps to mitigate the risk. When the allocation of risk is uncertain, mitigation costs may be duplicated by both parties—thereby increasing overall project costs.
- *Better Relationships.* When an issue arises that the agreement failed to address, feelings of surprise and unfairness may follow. The energy industry is one in which companies often engage in long-term relationships—whether manifested by a single, long-term contract or a series of repetitive, short-term contracts. Clarity on the front end pays ongoing dividends to the relationship.
- *Ease of Renegotiation.* Detailed contracts clearly allocate rights and obligations among the parties. This means that each party to the contract knows what it owes and what it is entitled to. Where contracts have not allocated all possible rights and obligations, there are fewer possible trade combinations, making renegotiation harder.
- *Less Litigation.* The greater the number of risks that are clearly allocated by an agreement, the less likely it becomes that litigation will later ensue. Litigators cannot do much with a clear contract because courts are very likely to enforce it according to the plain meaning of its terms.

While contract lawyers have long believed that more complete contracts were more efficient, we had no empirical proof to back up this supposition. We were

15. Hazel Glenn Beh, *Allocating the Risk of the Unforeseen, Subsurface and Latent Conditions in Construction Contracts: Is There Room for the Common Law?*, 46 U. KAN. L. REV. 115, 116 (1997).

16. STANLEY A. MARTIN AND LEAH A. ROCHWARG, *C*ONSTRUCTION LAW HANDBOOK 21-5 (3d ed. 2018) ("Since the right to assert a changed conditions claim must exist, if at all, by contract, recovery is dependent upon the precise terminology used in the differing site conditions clause . . . As a consequence, a successful differing site conditions claim under one contract may not be successful under a differently worded contract, even if the same conditions are encountered . . . the eventual outcome of each such claim is dependent upon the terms contained in the contract documents.").

finally proven right when two professors compared more than 3,000 loan agreements filed with the United States Securities & Exchange Commission.[17] The professors used "several measures of contractual detail" to compare the financial performance of the banks based on the level of detail in certain loan agreements:

> Consistent with the idea that more complete contracts create less holdup and therefore allow for greater investment efficiency, we find that subsequent annual return on assets and sales growth are higher for firms which sign more detailed loan contracts, conditional on other contractual features such as loan size and covenant makeup. The overall evidence suggests that firms which are able to sign more complete loan contracts are better able to exercise their growth opportunities.[18]

While the context of the University of Texas and University of Georgia study was loan agreements, similar benefits should exist for construction and services agreements. From an owner's perspective, increased certainty regarding when adjustments are owed will result in owners paying less to contractors for unenumerated claims. From a contractor's perspective, more complete clauses better ensure the contractor will be paid for its enumerated claims. The result should be that both parties receive more or less what they expected when they signed the contract, leading to more predictable investments for both.

III. THE PURPOSE OF ADJUSTMENTS IN CONSTRUCTION/SERVICES AGREEMENTS

At the time that a construction or services agreement is signed, there are many risks lurking in the future. Final designs from engineers may be different from those that existed when a construction contract was signed.[19] The route of a pipeline or the location of a facility could be modified to mitigate environmental risks or to avoid historical sites or cultural resources.[20] The site conditions where the work will take place could be another known unknown. While the contractor may have been provided with geological assessment data regarding the site, what happens if the actual conditions differ from such data? In all of these cases, both the owner and contractor are fully committed. The transaction between them cannot be undone. The work must go on.

Perhaps the easiest way to appreciate the value of adjustment clauses is to consider what would happen if a construction or services contract lacked one. Posit an agreement under which the contractor bore all risks. The lump sum it agreed to could never be increased. The schedule could never be extended. What

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17. *See* Bernhard Ganglmair & Malcolm Wardlaw, *Measuring Contract Completeness: A Text Based Analysis of Loan Agreements* 2 (Dec. 27, 2015), https://www.aeaweb.org/conference/2016/retrieve.php?pdfid=1166.

18. *Id.* at 4.

19. John W. Gaskins, *Delays, Suspensions, and Available Remedies Under Government Contracts*, 44 MINN. L. REV. 75, 75 (1959) ("Few . . . contracts which involve substantial sums of money are ever completed in strict accordance with their original technical requirements and drawings. Instead, changes and revisions in the work are usually ordered by the [owner] during performance of the contract.").

20. *See, e.g.,* Standing Rock Sioux Tribe v. U.S. Army Corps of Engineers, 205 F. Supp. 3d 4, 14 (D.D.C. 2016) ("By the time the company finally settled on a construction path . . . the pipeline route had been modified 140 times in North Dakota alone to avoid potential cultural resources.").

would this contract look like? The agreement would be a very expensive one because the contractor will have "insulated [itself] against both foreseeable and unforeseeable contingencies . . . through contingency factors in [its] price."[21] It also would show a very late completion date because the contractor would have added many weeks of contingency time to its schedule.[22]

What adjustment clauses ultimately do is reduce the need for contingency by promising the contractor more money and/or time if certain reasonably anticipated risks occur.[23] Good adjustment clauses make the prices in agreements more closely reflect the cost of the work in the absence of known unknowns. Good adjustment clauses make the schedules in agreements more closely reflect how long the work will take in the absence of known unknowns. Should one of these risks occur, the adjustment clause then will modify the price and schedule based on what has actually happened, instead of what people might have feared could have happened.

IV. DISCRETIONARY VERSUS ENUMERATED APPROACHES TO ADJUSTMENTS

A critical question for construction and services contracts is *which risks* should entitle the contractor to an adjustment. That question can either be addressed *post hoc*, after the contract has been signed and a risk has come to fruition, or *ex ante*, at the time a contract is being negotiated. In one camp are those (typically contractors) who want to postpone determinations, leaving considerable ambiguity in the contract about which risks get adjustments and which do not. In the other camp are those (typically owners) who want to identify and expressly address each of the known unknowns.

These divergent approaches have led to two general types of adjustment clauses:

- *Discretionary Adjustment Clauses.* Discretionary adjustment clauses set forth a general, often vague standard (e.g., "changed circumstances"), thereby leaving both parties with considerable discretion to make, accept, or reject claims.

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21. Gerritt W. Wesselink, *Prime Contractor's Responsibilities to the Government as Affected by the Subcontractor's Default*, 16 FED. B.J. 211, 211 (1956) ("The number of contingency charges contained in a price depends upon the number of risks and the nature of the risks which a prospective contractor believes he will incur during the course of performance. The [owner] is well aware of the fact that even in a firm fixed-price contract, a contractor has usually insulated himself against both foreseeable and unforeseeable contingencies, if not through a specific contract provision, then through contingency factors in his price.").

22. *See* Deane D. Nelson, *Contractor's Rights*, 34 J. ST. B. OF CAL. 352, 355 (1959) ("In that the contractor is assured of a remedy for [owner]-caused delays, there is less likelihood of the contractor including a contingency in his original bid or proposal for accomplishing the construction project.").

23. *See* MARTIN & ROCHWARG, *supra* note 16, at 20-7 ("Many courts and now legal commentators have permitted recovery of additional compensation for work already required by an existing contract if 'unanticipated and burdensome circumstances have been encountered in the performance of existing contracts . . . Such circumstance must, however, be of such a magnitude that to enforce the contract in accordance with its original terms would be unconscionable.") (citing Gregory G. Sarno, *Enforceability of Voluntary Promise of Additional Compensation Because of Unforeseen Difficulties in Performance of Existing Contract*, 85 A.L.R. 3d 259, 274, 292-294 (1978)).

- *Enumerated Adjustment Clauses.* Enumerated adjustment clauses limit adjustment claims to a list of well-defined circumstances.

Needless to say, the length (in number of words or pages) of a construction or services contract is largely a function of which of these two approaches it takes. Enumerated adjustment clauses typically provide standards for each of the grounds on which adjustments are to be granted and detailed procedures for applying them. This can easily increase the number of words in a contract by one-third or more. Discretionary adjustment clauses do not need as many words because it is up to the owner's project manager to balance all of the facts and circumstances (and perhaps consider the contractor's rights under common law) and then use his or her discretion in making a determination.

A. Discretionary Adjustment Clauses

Over the course of my career, I have observed that contractors tend to favor discretionary adjustment clauses. A typical mark-up of an enumerated adjustment clause by a contractor's counsel attempts to make it more discretionary. Arguments made in favor of discretionary adjustment clauses include the following:

- *Fear of Missing Something.* Contractors (or at least contractors' lawyers) fear the possibility that some event will occur that was unlisted (forgotten about or not thought of) in the enumerated adjustment clause. Discretionary adjustment clauses tend to leave the door open for a contractor to bring a greater variety of claims:

> Many courts . . . have permitted recovery of additional compensation for work already required by an existing contract if "unanticipated and burdensome circumstances [have been] encountered in the performance of existing contracts. . . ." [S]uch a change must relate either to the actual ability to perform the work as contemplated by the contract documents because of problems inherent in the work itself or to the existence of external factors that affect the work. Examples of the former include encountering subsurface conditions that substantially affect the contractor's ability to excavate, whereas examples of external conditions include labor strikes and the inability to secure necessary raw materials or equipment.[24]

When contractors express concern about leaving something out of the enumerated list, my response is, "What is missing from the list?" Typical answers to this question include far-fetched circumstances that almost always qualify as force majeure—which is, as described below, already an item on everyone's enumerated list.

- *Ambiguity Favors the Contractor.* Contractors tend to believe that ambiguity works in their favor, on the assumption that a tie (i.e., contractual silence) goes to the contractor (like the widely, if incorrectly, held belief in baseball that a tie goes to the runner).[25] The

24. MARTIN & ROCHWARG, *supra* note 16, at 20-7 to 20-9.

25. It is often assumed that under baseball's rules, the tie goes to the runner. But in fact, there is no such rule in baseball or softball. The runner is either out or safe. *See, e.g.*, College Softball Umpires Locker Room, available at: https://collegesoftballumpires.org/tie-goes-to-a-runner/. *See also* MLB rules, 7.01, 6.05(j) and

premise for this thinking is that courts or arbitration panels are more likely to side with the contractor (typically the smaller company) than the owner (typically the larger company).[26] However, contractors should be wary of such beliefs because courts have held that "[w]here one agrees to do, for a fixed sum, a thing possible to be performed, he will not be excused or become entitled to additional compensation because unforeseen difficulties are encountered."[27] Treatises on construction law have explained that "[t]his principle, which has withstood the test of time, is based on the notion that owners should not be responsible for the costs associated with bids from careless contractors who fail to realistically anticipate the site conditions to be encountered when pricing their work."[28] Even assuming that a contractor has a better chance of prevailing, there are other costs of pursuing litigation. When a contractor sues an owner, the contractor may no longer be considered for future projects by that owner—and other owners also may be less likely to select a litigious contractor. The owner may withhold final payments during a dispute, thereby requiring the contractor to borrow money to pay its subcontractors while it pursues litigation. Such considerations may render litigation impractical.

- *Trusting Each Other.* Contractors may believe that their longstanding, good relationships with the owners' project managers will result in them being treated fairly (and receiving adjustments). This is a variation of the "who needs a contract at all" argument. Unfortunately, not every project manager can be a King Solomon.[29] Different project managers may have varying perspectives as to what circumstances should give rise to an adjustment. Another project manager could be substituted, or the contractor might face a less permissive one on the next project. I personally have witnessed widely different treatment of contractor claims between projects because of the idiosyncrasies of project managers. Similar claims may be denied on one project and accepted on another one. Claims

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7.09(e), each of which provide that the runner is out unless the runner reaches the bag *before* being tagged or in the case of a force out, before the bag is tagged, discussed at https://bleacherreport.com/articles/225160-come-on-blue-tie-goes-to-the-runner-no-it-does-not.

26. While many construction agreements require mandatory arbitration of disputes, contractors may be unwise to place their faith in an arbitration panel. As Asselin and Harris explain, "[a]rbitrators' expertise is not necessarily as advantageous as may be assumed. Although arbitrators generally have more construction expertise than the average judge or juror, the supply of qualified arbitrators and methods of selecting arbitrators can result in less expertise than might be expected." Thomas H. Asselin and M. Catherine Harris, *How to Recognize, Preserve, Present, and Prosecute Construction Contractors' Delay Claims*, 40 S.C.L. REV. 943, 974 (1989).

27. U.S. v. Spearin, 248 U.S. 132, 135-36 (1918).

28. MARTIN & ROCHWARG, *supra* note 16, at 21-3 to 21-4.

29. Solomon is known for the case of two women who laid claim to the same child. When Solomon pronounced his judgment that the child be cut in half and shared between the women, one of the women quickly renounced her claim (thereby proving to Solomon that she was the rightful mother, because the rightful mother would never want to harm her own child). 1 *Kings* 3:5-12, 16-28.

made early in a project may be accepted (because there is still room in the budget) and denied later in a project (because the budget is dwindling). Is it really in the best interest of a contractor to have its adjustments subject to the vagaries of individuals whose perspectives and levels of experience may vary?[30] If trust was enough, we wouldn't need a contract at all,[31] or as movie mogul Samuel Goldwyn once quipped, "A verbal contract isn't worth the paper it is written on."[32]

- *Ability to Change the Rules.* Under a discretionary adjustment clause, lawyers are generally absent from the adjustment process—until someone threatens a lawsuit. This means that the parties' respective project managers are more in "control" of the adjustment process. They can largely do whatever they want, and no lawyer or auditor will question their compliance with the contract. They can make the rules up as they go along. In contrast, the enumerated adjustment clause will substantially determine (in advance) when the contractor is entitled to adjustments and when it is not. The owner's project manager generally must follow these rules (in the absence of an amendment to the agreement), even if he or she would like to grant the contractor an adjustment to help out the "relationship."
- *Extracontractual Assumptions.* Prices and schedules are based on a large number of assumptions—including about the contractor's own productivity. Most of these assumptions never make it into the scope of work or any other part of the contract. The owner may have no idea what the contractor's assumptions are, and there may be no record of what they were. Under a discretionary adjustment clause, a contractor preserves an option to seek price and time adjustments for variances between its own assumptions (which were never stated in the contract) and what actually happened.[33]

One of the deficiencies with discretionary adjustment clauses is uncertainty regarding the outcome of specific claims. Clauses that provide for the contractor

30. *See* John W. Gaskins, *Suspensions and Available Remedies Under Government Contracts*, 44 MINN. L. REV. 75, 76 (1959) (" . . . [I]nconsiderate action by the [owner] . . . may make an otherwise satisfactory contractual arrangement unprofitable, or even disastrous, for the contractor.").

31. *See* Wendy Netter Epstein, *Facilitating Incomplete Contracts*, 65 CASE W. RES. L. REV. 297, 299 (2014) ("Certainty is the reason parties formally contract rather than informally agree . . . [I]ncomplete contracts that fail to give adequate guidance to the parties about their duties and obligations are more likely to result in opportunistic behavior and litigation and make litigation more time consuming and costly if it does result.").

32. ALVA JOHNSTON, THE GREAT GOLDWYN 16 (1937).

33. For example, in *John A. Johnson Contracting Corp. v. United States*, "recovery was allowed for increased costs sustained as a result of defective roads which were constructed by the [owner] and used by the contractor in building a hospital project. The court held that both parties . . . *assumed* that [the contractor] would use the roads furnished by the [owner] as haul roads in connection with its building operations." Gaines V. Palmes, *Damages in Government Construction* Contracts, 25 FORDHAM L. REV. 621, 622 (1956) (explaining the decision in *John A. Johnson Contracting Corp. v. United States*, 132 F. Supp. 698 (1955)) (emphasis added).

to receive additional compensation for "changed circumstances" tend to generate fact-intensive disputes over what the circumstances were assumed to have been when the contract was signed. There may be emails and drafts supporting both sides of the claim, thereby leading to expensive disputes that are difficult to compromise.

Petrochem Services, Inc. v. United States exemplifies what can happen when a contract fails to expressly allocate a known risk. In that case, the US Navy solicited bids from contractors to clean up and remove oil that spilled from a storage tank.[34] The winning contractor, Petrochem, undertook an independent investigation of the facility to determine how much oil had spilled but found standing water was obscuring the containment area.[35] This made the quantity of the spill a known unknown for the contractor.

Petrochem submitted its pricing based on the assumption that only 6,000 gallons of oil had spilled. Petrochem ultimately removed 21,401 gallons of oil from the tank. It sought an equitable price adjustment, but was denied.[36] The government claimed that Petrochem had been verbally informed that the quantity of spilled oil was approximately 21,000 gallons while Petrochem claimed that it had not been so informed.[37]

The *Petrochem* case illustrates the risk of discretionary adjustment clauses for both contractors and owners. Instead of addressing the risk that quantities could be higher or lower and providing price adjustments for variances, the contract itself was silent. This silence led to a messy dispute over who said what to whom.[38]

Construction and services agreements with discretionary adjustment clauses also can lead to uncertainty regarding the amount of the adjustment. One example of this is the common law remedy of *quantum meruit*—that is, payment of a reasonable sum when none is provided in the contract. The remedy of *quantum meruit* has been pursued by contractors "in the case of changes and extras."[39] In *Sam Macri & Sons, Inc. v. United States*, a subcontractor entered into a unit price agreement to complete paving work on behalf of a prime contractor.[40] While the prime contractor argued that the amount of compensation (if any) should be at the unit prices set forth in the contract, the court disagreed, holding that because the additional work was outside the scope of the original contract and no price had been expressly agreed for the additional work, the subcontractor was entitled to recover on a quantum meruit basis for the extra work. Had the *Sam Macri & Sons* contract contained a clear enumerated adjustment clause, it would have specified both the circumstances and the amount of compensation owed (thereby likely precluding the *quantum meruit* claim).

34. Petrochem Servs., Inc. v. United States, 837 F.2d 1076 (Fed. Cir. 1988).
35. *Id.* at 1078.
36. *Id.*
37. *Id.*
38. *Petrochem* was remanded for additional factual findings concerning the conversations. *Id.* at 1801.
39. MARTIN & ROCHWARG, *supra* note 16, at 20-19.
40. Sam Macri & Sons, Inc. v. United States, 313 F.2d 119, 122 (9th Cir. 1963).

Discretionary adjustment clauses are akin to the story of ostriches sticking their head in the sand, "foolishly ignoring their problem, while hoping it will magically vanish."[41] When the project goes well, the discretionary adjustment approach appears to be a good one.[42] The parties saved a few hours of their time by avoiding the negotiation of various risks.[43] However, if claims grow in number or magnitude, the hours required to resolve them using a discretionary approach can be many times that required under an enumerated approach.[44] These hours also take place in the midst of the project, potentially distracting project teams from the job at hand.[45] Anthony Battelle, chief legal counsel to the Central Artery/Tunnel Project in Boston described his experience as follows:

> The potential for disputes is great because losses are real, and the assessment of cost impact resulting from delay is an imprecise science. Not only is the dispute potential high, but such disputes are factually and sometimes legally complicated, and typically they are time consuming to resolve—particularly through litigation. Given [the] circumstances, the CA/T project anticipated . . . an estimated ten to twenty thousand [disputes] by project completion.[46]

B. Enumerated Adjustment Clauses

It is no surprise that owners tend to prefer enumerated adjustment clauses. When something goes wrong on a project, enumerated adjustment clauses act as an important control on contractor price and time adjustments. But many of the advantages of enumerated adjustment clauses are also beneficial to contractors, including:

- *Meeting of the Minds.* When a contractor knows that its adjustments are limited to enumerated categories, the contractor is more likely to raise during negotiations all of the known unknowns that it is relying upon for its pricing. This serves an "information forcing"

41. Karl S. Kruszelnicki, *Ostrich Head in Sand*, ABC SCIENCE, (Nov. 2, 2006), http://www.abc.net.au/science/articles/2006/11/02/1777947.htm. This myth seems to have had its origins in Roman times, when Pliny wrote in his Natural Histories (circa AD 77) that ostriches "imagine, when they have thrust their head and neck into a bush, that the whole of their body is concealed."

42. *See* Avery W. Katz, *Contractual Incompleteness: A Transactional Perspective*, 56 CASE W. RES. L. REV. 169, 178 (2005) ("Writing and negotiating an additional term incurs a certain and immediate cost that may not be justified if the contingency it covers is sufficiently remote.").

43. Epstein, *supra* note 31, at 305 ("For law and economics scholars, the question of contract drafting strategy turns on costs: drafting costs, performance costs, and litigation costs, to be specific. Parties will draft contracts that minimize the sum of the costs likely to be incurred at these three stages.").

44. *Id.* at 306 ("[Richard Posner] suggests that pre-performance specification generally decreases the chance that a party will act opportunistically during contract performance and that the deal will result in litigation. In his view, parties are more likely to work out disputes before litigation if a contract is detailed and specific . . . [t]his makes detailed drafting efficient despite the transaction costs inherent in its undertaking.") (citing Richard A. Posner, *The Law and Economics of Contract Interpretation*, 83 TEX. L. REV. 1581, 1583, 1584, 1614 (2005)).

45. *See* Gilbert J. Ginsburg, *The Measure of Equitable Adjustments for Change Orders Under Fixed-Price Contracts*, 14 MIL. L. REV. 123, 135-136 (1961) ("Without the changes clause, normal contract administration would bog down, as it is not at all unusual to find tens and often hundreds of change orders issued under a single contract.").

46. Anthony E. Battelle, *The Growing Impact of AD on the Construction Industry: "Real Time" Dispute Processing on the Boston Central Artery/Tunnel Project*, THE CONSTR. LAWYER 13 (Nov. 1995).

function and ensures that the parties have an open conversation about what risks are present and which party will bear them.[47]

- *More Certainty.* The parties mutually agree in advance to a set of rules, which establish the circumstances under which a contractor is entitled to price and/or time adjustments. So long as the factual circumstances satisfy one of the enumerated categories, the contractor will receive an adjustment. Owners cannot use their subjective judgment to deny claims.[48]
- *Less Contingency.* Under a discretionary adjustment clause, the contractor is likely to include more contingency in its pricing to address the possibility that the owner's project manager will deny claims. In this respect, the owner effectively pays for some portion of known unknowns whether they come to pass or not.[49] In contrast, under an enumerated adjustment clause, the price paid by owners should be lower (because such contingency is unnecessary due to the express contractual assurance of an adjustment).[50]
- *Fewer Claims.* Since the grounds on which claims can brought are more limited, there should be fewer claims for price and time adjustments. This decreases the distraction and administrative resources that are consumed during a project.
- *Better Relationships.* Discretionary adjustment clauses can place considerable pressure on the project manager, as he or she takes on the added role of judge and jury. When the project manager decides against the contractor, it can cause strain in the business relationship, often leaving the contractor believing that it has not been treated fairly. In contrast, when a claim is denied under an enumerated adjustment clause, it is usually done by lawyers who are relying on express language in the contract (and the project manager is

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47. *See* Ruben Kraiem, *Leaving Money on the Table: Contract Practice in a Low-Trust Environment*, 42 COLUM. J. TRANSNAT'L L. 715, 738 (2004) ("Contracts are often, if not always, negotiated under non-ideal conditions, where there is real and unavoidable uncertainty, and at least some opposition of interests between the parties . . . There may be relevant information that is concealed or unknown, often for strategic reasons.").

48. In contrast, under the discretionary approach, contractors may assume they will be granted price adjustments for certain circumstances and not include any contingency for them. If the owner denies one of these categories, the contractor could find itself in a net loss position on the project.

49. *See* J.J. Kelly Co. v. United States, 69 F. Supp. 117, 120 (1947) (" . . . [R]etention of Article 9 in its present form in the government contracts would probably cost the Government more in the way of increased prices on such contracts hereinafter entered into than any possible savings that could be attained by retaining the article in its present form."). At the time of *J.J. Kelly Co.*, Article 9 in government contracts provided only an extension of time to a contractor during a delay that was not the contractor's fault.

50. Allocating Project Risk, POWER MAGAZINE (July 1, 2012), https://www.powermag.com/allocating-project-risk/ ("The data collected showed that if risk is inappropriately allocated, resulting financial consequences can be significant. Nearly 20% of the overall impact resulted from contractors increasing their contingencies in response to inappropriate risk-shifting by the owner. This indicates that if risk is inappropriately allocated to contractors, increased contingencies will often be passed to the owner. It may be more cost-efficient to retain the risk and use mitigation and management techniques to lower the costs in-house.") (citing CII Implementation Resource 210-3, Equitable Risk Allocation: A Legal Perspective).

not "responsible" for the denial). After all, the contractor agreed to the language in the contract and must live with it.

- *Decreased Volatility of Contractor's Profit.* Under the enumerated approach, the contractor should receive prompt payment for all of the known unknowns, as and when the risks materialize. While the contractor will no longer receive occasional windfalls from unspent contingency, it will avoid unexpected losses arising from insufficient contingency. This reduces the volatility (or range) of contractor's profit over projects, likely leading to greater financial stability.
- *Less Litigation.* The use of precise contract terms (and fewer vague ones) entails a tradeoff between up-front (negotiation costs) and back-end enforcement (litigation) costs: "When the parties agree to precise terms (or rules), they invest more at the front end to specify proxies in their contract, thereby leaving a smaller task for the enforcing court."[51] Enumerated adjustment clauses resolve (at the front-end) many questions that would otherwise be left to judges, juries, or arbitrators—thereby avoiding some disputes altogether and limiting the scope of others.

The enumerated adjustment clause makes contractors carefully think about the risks they face on a given project. As described below, lawyers can easily draft enumerated lists that capture the universe of categories. This leads to valuable commercial discussions and better awareness of risks by both parties. Contractors will be compensated for what actually happened and will not be left with potentially large windfalls or shortfalls. This more efficient outcome is beneficial to both parties.

V. ENUMERATED ADJUSTMENT CLAUSE CATEGORIES

Negotiating enumerated adjustment clauses consumes more time because the parties need to agree on (i) the categories comprising the enumerated list and (ii) the standards for each category. Fortunately, these categories do not change much whether the energy project is a natural gas pipeline, natural gas compressor station, oil pipeline, oil pipeline pump station, wind turbine, solar farm, or electricity plant. Most energy projects encounter a similar set of risks.

A. Written Change Orders/Directives (Changes to Scope of Work/Specifications)

Construction and services contracts typically contain several technical exhibits that describe the work required (scope of work) and the specifications for how such work should be completed (specifications). These exhibits can be modified by a written change order or change directive:[52]

51. Robert E. Scott & George G. Triantis*, Anticipating Litigation in Contract Design*, 115 YALE L.J. 814 (2005).

52. MARTIN & ROCHWARG, *supra* note 16, at 20-5 ("When the contract documents require changes and extras to be in writing, courts generally hold that a contractor who fails to obtain a written change order prior to

- *Change Orders*. A change order is "a written agreement between an owner [and contractor] that memorializes a change in the work, including an adjustment in the contract sum or time impact on the project schedule."[53] Because change orders modifying the scope of work or specifications must be mutually agreed, any resulting price or time adjustments should be resolved by the change order as well.
- *Change Directives*. If the parties cannot reach agreement on the adjustments, then the owner may be required to implement revisions via a change directive—and the contractor would then have the right to seek adjustments based on the change directive. A change directive is "a document that directs the contractor to proceed with changed work without a final agreement on price and time adjustments for the changed work."[54] Owners issue change directives "to allow the parties to proceed with changed work without final pricing in an attempt to keep the project moving forward toward timely completion."[55]

Thus, the first category for an enumerated adjustment clause is the issuance of a change directive by the owner. The contractor's burden is then to show how the modifications effected by the change directive increased its cost of performance or caused the work to take longer. If the parties have difficulty reaching agreement on the estimated impact of a change directive (at the time it is first issued), the final determination of the adjustments can be postponed until the work required by the change directive has been completed. At such time, the parties can more easily evaluate the actual costs and schedule impact.

Note that verbal change directives should be prohibited. The scope of work cannot be unilaterally modified by the owner unless a written change directive is issued, and the contractor cannot file a claim based on the scope of work being modified unless a written change directive has been issued. The requirement of a written change directive ensures that both parties know when the scope of work was modified and how it was modified.[56]

B. Differing Site Conditions

The cost of construction and services work is substantially affected by the "natural or man-made physical, surface, subsurface, and other conditions at the

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performing changes or extras will not be paid for that work.") (citing United States ex rel. McDonald v. Barney Wilkerson Constr. Co., 321 F. Supp. 1294 (D.N.M. 1971)).

53. William B. Westcott, *Change Orders vs. Construction Change Directives: The Devil Is in the Details*, THE CONST. LAWYER 34 (Winter 2016).

54. *Id.* (italics omitted).

55. *Id.* at 39.

56. Terry Dougherty, *Getting the Deal Done Right: Keys to the Effective Construction Contract*, THE NEBRASKA LAWYER 9 (Apr. 2006) ("Disputes over the scope of the contractor's work are one of the most common construction conflicts . . ." because " . . . [s]everal factors can make the definition of the contractor's work unclear. The description of the work itself could be vague. Perhaps the definition of the contract documents is unclear, making the work required by those documents also uncertain.").

site and the surrounding area as a whole."[57] While contractors may have an opportunity to visit the site, they rarely have the opportunity to undertake any extensive analysis of the subsurface conditions. As such, they must rely on geological assessments provided by the owner and other publicly available information about the location.

This means that certain site conditions may remain undetected—and thus cannot be priced into a contractor's bid. A differing site conditions clause establishes which unanticipated site conditions are the responsibility of the owner—versus the contractor. Martin and Rochwarg explain that the rationale for including a differing site conditions clause is to protect both the owner and the contractor from unnecessary, inefficient payments to one another:

> The rationale for differing site conditions clauses is to equitably manage the risk of unanticipated site conditions between the owner and contractor. The clause is a means by which both the owner and the contractor can eliminate unreasonable risks and contingencies. With such a clause, the contractor does not need to include large contingencies in its bid to cover the increased costs of performance in the event an unanticipated latent physical condition is encountered, and the owner is protected against windfall profits to the contractor if no such condition is encountered. Conversely, if such a contingency is not included in the contractor's price, but an unexpected physical condition is encountered, the owner obtains a benefit for which payment has not been made, while the contractor incurs unanticipated costs, and may be forced into an adverse financial position that could jeopardize the completion of the project. A changed site condition clause removes this risk[.][58]

Differing site conditions clauses create a more accurate and orderly bidding process that benefits both contractors and owners. "The primary purpose of differing site conditions clauses within construction contracts is to encourage contract bidders to submit their lowest bids rather than build cushions into their bids for contingencies that may never occur."[59] A differing site conditions clause provides contractors with a straightforward contractual remedy (of compensation) if differing site conditions are encountered.[60]

By bearing the risk for differing site conditions, owners receive bids closer to the true cost of the work. Owners can then engage the most efficient contractor rather than the contractor who may have been a poor estimator of the risk of encountering differing site conditions and thus submitted the lowest bid.[61] Efficient

57. S. Scott Gaille, *Unanticipated Site Conditions & Energy Construction Agreements*, GAILLE ENERGY BLOG, ISSUE 78 (June 28, 2019), https://gaillelaw.com/2019/06/28/unanticipated-site-conditions-energy-construction-agreements-gaille-energy-blog-issue-78/.

58. MARTIN & ROCHWARG, *supra* note 16, at 21-7 to 21-8.

59. Beh, *supra* note 15, at 132.

60. MARTIN & ROCHWARG, *supra* note 16, at 21-5 ("Unless a changed conditions clause exists in the underlying contract, the contractor must find a different theory for recovery or assume the unforeseen conditions and bear all attendant additional costs.") (citing Eastern Tunneling Corp v. Southgate Sanitation, 487 F. Supp. 109 (D. Colo. 1979)).

61. *See* Justin Sweet, *Standard Construction Contracts: Some Advice to Construction Lawyers*, 40 S.C.L. REV. 823, 829 (1989) ("The fiercely competitive construction industry or particular market conditions may generate a "gambler"—a contractor who will *not* build risks into the contract price. A gambler wants to win out over the others at all costs and may plan to "beat" the fixed price by claims.") (emphasis in original).

contractors avoid losing bids to less efficient contractors who either underestimated the risk of differing site conditions or intended to seek claims after entering the contract.

Large, well-capitalized owners may also have an interest in absorbing costs for differing site conditions, even if it increases the owner's costs:

> One very costly job may drive a contractor out of business, eventually hurting the large owner who requires specialized services in multiple contracts. Absorbing the cost of unforeseen conditions protects the industries upon which the large owner depends. Moreover, contractors may elect not to bid on high-risk projects, finding the risks unacceptably high.[62]

Several commentators and court cases have sought to distinguish between two "types" of changed condition claims:[63]

> At least in terms of who will foot the bill for a truly unforeseen site condition (which we all care about) . . . the analysis will always be the same. . . . "Type 1" differing site condition claims involve site conditions that differ materially from the conditions planned for the construction contract. "Type 1" claims rely on the legal doctrines of misrepresentation and implied warranty to provide relief to a contractor unfortunate enough to encounter a site condition not envisioned in the parties' contract. In contrast, "Type 2" claims involve site conditions that differ materially from those conditions that are "normally encountered." "Type 2" claims rely on the equitable doctrine of mutual mistake to provide relief to a contractor for site conditions that were "unknown" or were of an "unusual nature." . . . [W]hen reviewing a differing site conditions claim, courts will always ask the same question: were the conditions the contractor experienced on-site "reasonably foreseeable?"[64]

Such common law distinctions among misrepresentations, implied warranties, and mutual mistakes may increase the probability of a dispute—and also its costs. Instead of parties knowing what they will pay or receive at the front end, the outcome may require a judge or arbitrator to apply the precedents of many cases involving other parties. The enumerated adjustment clause does away with this complexity. Instead, the parties mutually agree on an express standard. If a site condition satisfies the contract's standard, then an adjustment is required; if not, then no adjustment is allowed.

Consider the following definition of "Differing Site Condition" from a contract following an enumerated adjustment approach:

> "Differing Site Condition" means, as of the effective date, a site condition that the existence of (or risk of encountering it): (a) was not identified in any written documents (including geological reports) received by contractor; (b) would not have been recognized by a contractor specializing in the performance of similar work (assuming good industry practices); and (c) was not actually known by any member of contractor group.

The preceding prongs of the test capture three ways in which a site condition becomes reasonably foreseeable. Subpart (a) addresses the situation in which owners provide geological assessment reports prior to the signing of a construction

62. Beh, *supra* note 15, at 136.

63. *See, e.g.*, AIA Document A201, Sec. 3.7.4.

64. Don Gregory, *"Type 1" vs. "Type 2" Differing Site Condition Claims: Distinction Without Difference*, OHIO CONST. LAW (Feb. 16, 2015), https://ohioconstructionlaw.keglerbrown.com/2015/02/type-1-vs-type-2-differing-site-condition-claims-distinction-without-difference/.

contract. These geological assessments can be helpful in resolving these disputes because they establish a third-party baseline against which to compare the actual site conditions. Every site condition identified in the geological assessment report is reasonably foreseeable. Subpart (b) captures those items that may not have been disclosed but would ordinarily have been identified by a typical contractor, and subpart (c) captures actual knowledge, such as might be obtained by a contractor who has previously worked at the same location.[65]

The "risk of encountering" language also is important because geological assessments are typically samples taken over a large area. For example, posit a geological report comprised of ten bore holes, each taken every 100 yards. Two of these bore holes encountered boulders. The contractor designed its excavations to avoid the two boulders identified, but then encountered a third boulder at a location between two of the bore holes. Is the third boulder a differing site condition? If the language "risk of encountering it" is present, then the answer is obviously no—because the report clearly showed the presence of boulders in the area (if there were two, there are likely more). If such language is missing, the contractor might argue that the new boulder was a differing site condition because that specific boulder was not identified or otherwise capable of being known about prior to excavation.

In all cases, the contract should provide that the contractor should only be entitled to receive adjustments for site conditions that qualify as "differing site conditions." All other site conditions are at the risk and expense of the contractor.

C. Owner-Caused Delay

Typical claims for owner-caused delay include the owner's failure to timely deliver materials that the contractor needs for its work—or government permits or private right-of-way agreements that the owner has committed to timely obtain. Delays caused by the owner can be financially devastating. As the Court of Claims explained:

> When a contractor has scores of employees, who must be paid for semi or total idleness during a period of delay through no fault of his own, but which is due to the wrongful acts or omissions of the other party to the contract, and at the same time his bonds, his interest, his capital investment, his overhead, his employees' wages, and his rental or use of machinery must go on, there is brought home to him in a very real and sometimes in a bankrupting way the heartbreaking realization that no mere extension of time will compensate him for the additional outlay of these expensive items.[66]

It is in the interest of both owners and contractors to contractually determine *ex ante* if and when additional compensation will be provided for owner-caused delay, as this will serve to reduce contingency from contractor bids by reducing

65. The parties also could create lists of deemed differing site conditions, which give rise to adjustments whether or not they were disclosed in advance. This might be necessary to avoid excessive contingency based on the low risk of an expensive site condition.

66. *J.J. Kelly Co.*, 69 F. Supp. at 120.

financial risk to contractors.[67] Contracts have traditionally defined owner-caused delay as "an act or omission of owner that prevented the contractor from performing its planned work." However, such language is too broad and can lead to misunderstandings about what the owner is required to provide, and when. A better approach for handling owner-caused delay is to list the deliverables that the contractor is relying upon in an exhibit to the contract. A definition of owner-caused delay along the following lines accomplishes this:

> "Owner-Caused Delay" means the owner's failure to achieve a precursor to contractor's work (that is expressly identified in the exhibits to this agreement) on or before the date required for such precursor (that is expressly set forth in the exhibits to this agreement) and such failure is the sole cause for contractor being unable to commence scheduled work.

The preceding definition ensures that the parties mutually agree on the required deliverables and the dates they are due, and then list them in an exhibit. It also ensures that the contractor cannot seek an adjustment for cases of concurrent delay—for example, if the owner's materials were late but the contractor's crew also was late and could not yet use them.[68]

D. Owner Suspension

Suspensions of the work can happen for a variety of reasons. The standard for owner suspension should make clear that contractor is only entitled to adjustments to the extent that the suspension was for the *owner's* own convenience—and not, for example, because of the acts or omissions of the contractor (e.g., if the contractor's safety violation results in the owner issuing a work stoppage, that should not constitute an unrestricted suspension).[69] The second important component of an owner suspension standard is that it must be in writing. This ensures that all parties know that such a suspension has occurred and when it occurred, thereby avoiding confusion about verbal statements.

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67. *Id.* ("If [they remain responsible for owner-caused delays], contractors in making their bids will necessarily make allowances for these possibilities and conditions which might result in delay through no fault of the contractor and which might greatly increase the cost of construction. As a matter of practical necessity their bids will be greater.").

68. Asselin & Harris, *supra* note 26, at 945 ("Delays are deemed to be concurrent when both the owner and contractor are partially responsible. Generally, this occurs when both parties are responsible for delays to the overall completion of the project as a result of simultaneous delays to work activities in their respective control.").

69. *See* Richard J. Wittbrodt and Lynsey M. Eaton, *Understanding Contractual Suspension Terms: A Risk Management Tool for Owners and Contractors*, REAL PROP. L. REPORTER 2-3 (Sept. 2010), https://www.gibbsgiden.com/wp-content/uploads/2018/07/Understanding-Contractual-Suspension-Terms.pdf (citing Associated General Contractors of America Document No. 200 §11.1.1) ("11.1.1 Owner Suspension. Should the Owner order the Contractor in writing to suspend, delay, or interrupt the performance of the Work for such period of time as may be determined to be appropriate *for the convenience of the Owner and not due to any act or omission of the Contractor* . . . [t]he Contract Price and Contract Time shall be equitably adjusted by Change Order for the cost and delay resulting from any such suspension.") (emphasis added).

E. Force Majeure

Force majeure definitions typically are comprised of three parts: (a) a general standard, such as “any circumstance that is not within the reasonable control, directly or indirectly, of the party affected, but only if and to the extent that such circumstance cannot be prevented, avoided, or removed by such party”; (b) a non-exclusive list of examples of force majeure (wars, disasters, strikes, fires, government actions, etc.); and (c) a list of events that *do not* constitute force majeure.[70] Most of the variance between force majeure clauses in construction and services agreements takes place with respect to (c)—the exclusions from force majeure.

In addition to typical exclusions such as economic hardship, late payment of money, and changes in market conditions, other carve-outs are becoming more common. These carve-outs typically coincide with specific circumstances (that would ordinarily qualify as force majeure) that the parties wish to treat differently. For example, the owner may wish to grant price adjustments for most force majeure events, but not for weather—or alternatively, the owner may wish to grant price adjustments for weather, but not for most force majeure events. Such carve-outs provide flexibility to handle different types of force majeure under varying standards.

1. Adverse Weather

Weather is the most common example of a force majeure carve-out. The force majeure clause may exclude all weather except for named tropical storms and declared disasters. The excluded “regular” weather events are then handled under a new definition, such as the following:

> “Adverse Weather” means an hour during which weather (other than Force Majeure) occurring at the work site prevents a majority of contractor’s full-time personnel from working, in each case, assuming the use of good industry practices by contractor to mitigate the effects of such weather.

Note that in the above definition, relief for adverse weather requires that a majority of the personnel be prevented from working during an hour—thereby excluding certain lesser weather impacts. The agreement also can introduce the concept of deductibles, whereby adverse weather would not give rise to an adjustment until a certain number of adverse weather hours had occurred (e.g. seventy-two hours of adverse weather). In such a case, the presumption would be that the contractor’s pricing already included contingency for seventy-two hours of weather.

70. *See generally* Jay D. Kelley, *So What’s Your Excuse? An Analysis of Force Majeure Claims*, 2 TEX. J. OIL AND ENERGY L. 91, 114 (2007).

2. Protester-Caused Delay

Because "[c]limate change has become a divisive political issue in the United States, and it appears likely to remain so for the foreseeable future," on-site protesting has become a greater threat to American energy projects.[71] Protestors generally turn up at pipeline right-of-ways and other energy project locations because of their view that oil and natural gas energy development " . . . contribut[es] to the nation's continued reliance on fossil fuels."[72] Wind turbines also have become targets for protesters who are concerned about damage to view corridors and bird life. Such developments have led some owners and contractors to expressly address the risk of protester-caused delays. A suggested definition of Protester-Caused Delay might read as follows:

> "Protester-Caused Delay" means: (a) the presence at the site of third-party protesters (other than contractor's personnel) who are demonstrating against the construction of the facility or the actions of owner (and not, by way of example, demonstrating against actions of contractor or a government instrumentality); (b) such protestors' actions are the sole cause for contractor being unable to commence scheduled work; and (c) contractor was unable to avoid the impact of such protesters.

Note that protest activity must be directed at the owner or its facility and not at the contractor or the government, more generally. For example, if protesters target the owner of a construction company due to a controversial social media post made by him or her, then no adjustment would be owed. Similar to the definition of owner-caused delay above, this definition also ensures that the contractor cannot seek compensation in instances of concurrent delay (e.g., protestors are blocking the right-of-way, but the contractor's crew is not otherwise ready to commence work).

3. Effects of Widespread Disease (COVID-19)

As a result of COVID-19, construction and services agreements now typically address those risks associated with pandemics, epidemics, and diseases. The negotiation of such COVID-19 clauses initially reflected considerable tension between parties, with contractors "attempt[ing] to negotiate a broad definition of a COVID-19 event to include any delays or disruptions to labor, materials, supplies, or manufacturing arising out of or relating to the pandemic, including on account of quarantines, shelter-in-place orders, and similar restrictions"[73] and owners "expect[ing] that contractors . . . will have accounted for any known and reasonably foreseeable COVID-19 restrictions or requirements and . . . seek[ing] to limit the contractor's relief only to new or unforeseeable events."[74]

My preference is to leverage the applicable law and COVID-19 guidelines into the standard as illustrated in the definition of "Effects of Widespread Disease" below:

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71. S. Scott Gaille, *How Political Risk Associated With Climate Change Is Impacting Pipeline Construction Agreements*, 40 ENERGY L.J. 111, 128 (2019).

72. *Id.*

73. Owino-Trice & Puri, *supra* note 12, at 62.

74. *Id.*

> ”Effects of Widespread Disease” means that applicable law requires that some or all of the contractor’s work be suspended due to a disease, epidemic, or pandemic (including COVID-19).

If the binding COVID-19 requirements for essential workers require a quarantine for personnel who come into close contact with an infected co-worker, the suspension of work resulting from such government-mandated quarantine would give rise to adjustments. In contrast, if the contractor’s personnel refused to work due to fear of contracting COVID-19, no adjustments would be granted. Thus, the standard proposed above is more objective because it allows the government to determine when a work stoppage is compensable. As with the prior carve-outs, the definition of force majeure also would need to exclude any effects from diseases, epidemics, or pandemics (as they would instead be treated under the definition “Effects of Widespread Disease”).

VI. WHICH CATEGORIES SHOULD RECEIVE BOTH PRICE AND TIME ADJUSTMENTS AND WHICH CATEGORIES SHOULD RECEIVE ONLY TIME ADJUSTMENTS?

Once the parties reach agreement on the list of enumerated grounds for adjustments, the next question is:

Which categories give rise to both price and time adjustments and which give rise to time adjustments only?

As a general rule, any category within the owner’s control should give rise to both price and time adjustments. These categories include change directives issued by the owner, owner-caused delays, and owner suspensions. Differing site conditions usually also are thought to be “within the owner’s control” because the owner has selected the location and bears some responsibility for geological testing. In all of the preceding four cases, the owner is typically responsible for both price and time adjustments.

In contrast, categories outside of both the owner’s and contractor’s control generally result in the contractor receiving only additional time to complete the work—these categories do not give rise to price adjustments. Practitioners often refer to such events as “time-no-money.”[75] The “time-no-money” approach allocates the risk and cost of dealing with force majeure and all of its sub-categories to the contractor (bad weather, protester-caused delays, and COVID-19).[76] The principal costs incurred by the contractor when a “time-no-money” event occurs are those associated with delay.[77] Though personnel and equipment are unable to

75. Asselin & Harris, *supra* note 26, at 944.

76. *Id.*

77. Costs associated with delay are not a trivial matter. As one scholar put it, “[I] would hazard the guess that more contractors have been bankrupted by delays in performance than all other causes combined. Anyone with a modicum of experience in construction work knows that time costs money and that the normal effect of any delay – whether due to changes, bad weather, or other causes – is to increase the cost of the job.” Joel P. Shedd, Jr., *The* Rice *Doctrine and the Ripple Effects of Changes*, 32 GEO. WASH. L. REV. 62, 69 (1963).

work, the contractor must still maintain personnel and equipment in a state of readiness to resume work the moment circumstances allow. Thus, "although the direct labor hours required to perform the work may remain unchanged, the contractor's labor costs increase because the period of time necessary to complete the work increases."[78] In addition to increased labor costs, contractors also incur delay costs from idle equipment, additional bond and insurance premiums, extended field office expenses (e.g. job site overhead), and extended home office overhead.[79]

Reasons why the "time-no-money" approach became industry practice for events outside the control of both the owner and contractor include:

- *Sharing of Costs – Each Party Bears Its Own Costs.* In the event of a work stoppage caused by neither party, both parties are incurring costs. While the contractor may be absorbing the costs of idle people and equipment, so too is the owner absorbing the costs of its idle project team—and presumably also lost revenues from an energy facility that will come on line later than originally scheduled. Time-no-money results in each party bearing its own losses.
- *Owner Should Not Become Contractor's Insurance Company.* The owner is paying the contractor for project results and does not intend to insure the contractor against business interruptions. Thus, the owner does not guarantee that weather and other circumstances will allow the contractor to work every single day between commencement and completion. The owner should not have to insure the contractor for its own inability to work.
- *Moral Hazard*. Contracts should seek to avoid moral hazards—that is, diminishing a party's incentive to mitigate risks by making someone else responsible for its consequences. Price adjustments for force majeure and similar circumstances raise the specter of a moral hazard because contractor is best positioned to take precautions (in advance) to protect its work against such risks and also can reduce costs by promptly demobilizing personnel and equipment.[80]

At the end of the day, the practical effect of "time-no-money" is that the contractor is self-insuring against the risk of force majeure and similar events. It does so by including some contingency in its pricing. For example, a contractor that bears the risk for weather-related interruptions will usually be paid higher rates than a contractor that has the right to receive price adjustments during weather

78. Asselin & Harris, *supra* note 26, at 944.

79. Thomas J. Kelleher, Jr., Eric L. Nelson & Garrett E Miller, *The Resurrection of* Rice? *The Evolution (and De-Evolution) of the Ability of Contractors to Recover Delay Damages on Federal Government Construction Contracts*, 39 PUB. CONTRACT L.J. 305, 306 (2010).

80. *See* Beatrice A. Beltran, *Posner and Tort Law As Insurance*, 7 CONN. INS. L.J. 153, 172-73 (2001) (summarizing the logic motivating Judge Richard Posner's decision in *Pomer v. Schoolman*, 875 F.2d 1262 (7th Cir. 1989)) ("[the farmhand] knew that the accident was caused only by his momentary lapse of judgment . . . Thus in terms of deterrence, [the farmhand] was in the best possible position to prevent this accident. It would be in error to shift the responsibility for this gruesome accident onto other parties who were in no position to prevent the accident.").

standby.[81] When such higher rates exceed the actual costs incurred for weather, the contractor makes excess profit—which can be used as a rainy-day fund (for those future projects in which weather costs may exceed the contractor's contingency).

The alternative to "time-no-money"—that is, price adjustments for circumstances beyond the owner's control—means that the owner is insuring the contractor for these costs (typically through payment of standby time). In such cases, the contractor's rates should be lower because it will have no contingency built into them. The principal reason that categories such as adverse weather, protestor delay, and widespread disease have been separated from force majeure is to allow the owner flexibility to insure the contractor for only certain types of force majeure events. This separation allows the owner to balance the contingency required by the contractor (*i.e.*, the contractor's cost of self-insurance) versus the owner providing insurance for such an event.

When does it make sense for an agreement to offer a price adjustment for a circumstance that is beyond both parties' control? The short answer is when the *known unknown* events are subject to *highly variable costs*. High variability can drive up contractor contingencies (for self-insurance), potentially leading to contractor windfalls if the risk comes in on the lower side of the predicted range. For example, consider a project in the Gulf of Mexico during hurricane season. The contractor has a 2-in-3 chance of paying nothing (because no hurricane occurs) and a 1-in-3 chance of incurring a storm and paying $1,000,000. The contractor proposes a contingency of $500,000 (and therefore agrees to bear the full $1,000,000 cost if a storm strikes). In such a case, the owner is faced with paying $500,000 whether a storm comes or not. Rather than lose a certain $500,000 as a contingency payment to the contractor, the owner may opt to keep the $500,000 and instead provide a price adjustment for named storms on the basis that the expected value of a hurricane payout (1/3 chance of paying $1,000,000 = $333,333) is less than the contingency proposed by contractor.

Another factor that can influence price adjustments is the duration of the work. The longer the project, the easier it is for a contractor to bear the risk of several days of delay and spread those costs across the overall project. For example, if a vessel is laying a pipeline over twenty-five weeks, even if a storm shuts down work for a week, that is only ~4% of additional cost; if a vessel is undertaking a two-week repair operation, and a storm shuts down work for one week, that is ~50% of additional cost.

Regardless of which party bears the risk, both must be mindful of mitigation. Neither the owner nor the contractor should be responsible for indefinite standby. When costs of demobilization (and remobilization) are less than paying for personnel and equipment to standby, the contractor should (absent contrary

81. Robert B. Clark, *Government-Caused Delays in the Performance of Federal Contracts: The Impact of the Contract Clauses*, 22 MIL. L. REV. 1, 69 (1963) ("[A] fallacy . . . lies in the assumption that contractors are willing to run risks at no cost . . . by and large the idea of running a risk without compensation is repugnant to a businessman. He has a minimum below which he will not go. This will . . . vary from contractor to contractor because the hope of an award is a powerful incentive. However, it is not so powerful as to completely eliminate contingency reserves. If the contrary were true, the insuring of weather risks would not have attained universal acceptance.").

directions from the owner) furlough personnel and demobilize equipment to mitigate standby costs.

Even if a price adjustment is granted for a circumstance beyond both parties' control, the parties should consider placing additional controls on the amount of such price adjustments, including:

- *Cap on Duration.* If the owner is responsible for actual standby or delay costs, consider placing a cap on the maximum duration of any individual standby period (or standby time cumulatively over the course of the contract). This ensures that the contractor is covered for finite periods of time when demobilization would not make sense—but minimizes the probability of a dispute over a longer shutdown.
- *Declining Payments.* The price adjustments also could be calibrated to include anticipated furloughs and demobilizations. For example, the first two days of an event might assume full standby, but thereafter, the amounts of standby might decline (90% on day three, 80% on day four, etc.).
- *Owner Elections.* If the owner is paying for standby time, then the owner should have the right to elect which personnel and equipment are placed on standby and which are demobilized and furloughed. This helps mitigate the moral hazard risk.

COVID-19 quarantines have presented a particularly challenging case for whether price adjustments should be granted or not. The moral hazard issues presented by COVID-19 are greater than those of other categories because of the level of control that contractors have in either mitigating or exacerbating this risk, including:

- the nature of work force housing (individual or shared hotel rooms);
- how people are transported to and from the work site (individually, car pools, or buses);
- the manner in which personnel take their meals (individually or communally; take-out or dine-in);
- whether or not curfews are in place for personnel (e.g. no after-hours visits to bars);
- social distancing, mask wearing, and air purification at contractor's own offices;
- the timing and frequency of COVID-19 testing; and
- vaccination requirements.

If the owner pays price adjustments for a contractor's COVID-19 standby costs, then the contractor will be less incentivized to take precautions that would mitigate the risk, but might be somewhat costly to implement. The counter argument is that uncompensated contractors may have an incentive to send asymptomatic (but exposed or recovering) workers back to the site too early, thereby potentially leading to more COVID-19 cases (than if workers were quarantined for longer periods).

In all of the above cases, the question of whether or not price adjustments should be allowed for different circumstances is a discussion that should be had at the outset. Doing so ensures that the contractor's pricing reflects the risks it is bearing under the construction or services agreement—and that no contingency is included in the pricing for any circumstances for which a price adjustment is available (and that no extra days are built into the schedule for circumstances for which a time adjustment is available). Enumerated adjustments also enable the company to make efficient decisions about the tradeoffs between contingency (paying the contractor to bear a risk) and price adjustments (lower pricing plus paying the actual costs when the risks occur).

VII. CONCLUSION

While contractors continue to favor discretionary approaches to adjustment clauses, there are many reasons to believe that discretionary adjustment clauses lead to inefficiencies detrimental to both owners and contractors. The discretionary adjustment clause sets up a contractor for a potential catastrophe in which it has included insufficient contingency but yet is faced with an owner's denial of a claim—a claim that is not expressly allowed under the contract and therefore is difficult to enforce in the courts. Enumerated adjustment clauses offer a contractor greater assurance of its claim being granted by the owner, and even if it is not, a higher probability of enforcing the claim in the courts. While owners already tend to support enumerated adjustment clauses for purposes of curtailing excessive or unjustified contractor claims, enumerated clauses make construction and services agreements more complete, thereby reducing inefficiencies such as contingencies and litigation costs.

FERC'S POLICIES ARE INCENTIVIZING THE EXERCISE OF MARKET POWER THROUGH UNDER-DEVELOPMENT OF OIL AND NATURAL GAS LIQUIDS PIPELINE CAPACITY

Daniel S. Arthur & Michael R. Tolleth[*]

Synopsis: The Federal Energy Regulatory Commission (FERC or the Commission) regulates oil and natural gas liquids (NGL) pipelines rates.[1] As the rate level permitted to be charged is a crucial element in a decision for a pipeline to invest in capacity, FERC's policies toward regulating rates have a direct impact on investment in oil and NGL pipeline infrastructure.

Fundamental principles of competitive economics dictate that optimal development of oil pipeline transportation capacity is achieved when pipeline transportation rates reflect the long-run marginal cost of developing incremental capacity, as would be the case in a workably competitive market.[2] However, certain of FERC's current policies for review of negotiated "committed" rates and for approving market-based rate authority actually work against the objective of promoting optimal investment in pipeline infrastructure. That is, rather than ensuring oil pipeline rates are set at competitive levels reflective of long-run marginal cost, FERC's current approach instead incentivizes pipeline companies to exploit the natural monopoly characteristics of the oil pipeline industry to under-develop capacity in an exercise of market power.

With respect to approving market-based rates, FERC's policies for assessing whether a particular oil pipeline transportation market is competitive effectively begin with the tautological assumption that all the prevailing prices and alternatives in that market reflect competitive circumstances.[3] In addition, with respect to the approval of contract rates involving multi-year take-or-pay volume-commitments, FERC has stated it does not have an obligation to review negotiated committed shipper rates based on whether the rates produce a reasonable, rather than excessive, return on investment for the pipeline.[4]

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1. Interstate Commerce Act, 49 U.S.C. app. §§1(5), 2, 3(1), 15(1), 15(7) (1988).

2. "Long-run marginal cost" refers to the costs of providing incremental output over time horizons when all factors of production can be changed. A "short-run marginal cost" refers to the incremental cost of producing an incremental unit in the short-run, when factors of production are fixed. Thus, long-run marginal cost includes incremental capital investment associated with incremental output, whereas short-run marginal cost includes only the variable operating costs required to provide one more unit of output.

3. The specific flawed FERC statement and resulting policies referenced here are identified and discussed in sections I.B and III.A below.

4. The specific flawed statement and resulting policies referenced here are identified and discussed in sections I.B, IV.A. and IV.B below.

We recommend the Commission discontinue its economically unsound presumptions that all "used" alternatives and prevailing rate levels are competitive for purposes of market power analysis. Instead, we recommend that the Commission adhere to the fundamental principles of competitive economics by affirmatively clarifying that a reasonable proxy for a competitive rate for purposes of an oil pipeline market power analysis should be tied to the underlying costs of providing the transportation service at issue. To remedy the incentive for the underdevelopment of capacity supported by committed shipper contracts, we recommend the Commission clarify that any "duty to support" contract clauses do not foreclose the ability of shippers to challenge the reasonableness of the rates.

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I. INTRODUCTION

The Federal Energy Regulatory Commission (FERC or the Commission) does not have regulatory authority regarding entry, abandonment, or expansion of oil and natural gas liquids (NGL) pipelines,[5] but it does have regulatory authority over the rates charged by such pipelines.[6] As the level of rates permitted to be charged is a crucial element in a decision for a pipeline to construct a new system or invest in a change in the capacity of its operations, FERC's policies for regulating rates have a direct impact on investment in oil and NGL pipeline infrastructure.

From a policy perspective, the objective of FERC's practices and precedents for regulating oil and NGL pipeline rates should promote the development of infrastructure that is supported by adequate market demand at rates that are compensatory, but not excessive. However, as discussed below, FERC's recent statements that it will not review the reasonableness of committed shipper rates on oil and NGL pipelines—as well as certain key aspects of the Commission's method for evaluating whether oil pipelines possess market power in the context of approving market-based ratemaking authority—actually serve to incentivize oil and NGL pipelines to exercise market power by allowing them to profitably increase rates through an under-development of capacity.

5. *See*, *e.g.*, Farmers Union Cent. Exch. v. FERC, 584 F.2d 408, 410 n.1 (D.C. Cir. 1978) (stating that the Interstate Commerce Commission, FERC's predecessor in interest, did not have regulatory authority over acquisition of a pipeline company); Arco Alaska v. FERC, 89 F.3d 878 (D.C. Cir. 1996) (holding that FERC did not have regulatory authority to require carriers to "publish operating rules governing allocation of capacity among carriers").

6. Interstate Commerce Act, 49 U.S.C. app. §§ 1(5), 2, 3(1), 15(1), 15(7) (1988).

A. Background – FERC's Regulation of Oil Pipeline Rates

Congress delegated oil pipeline ratemaking authority to FERC with the mandate that rates be "just and reasonable."[7] The D.C. Circuit Court noted in *Farmers Union II* that for rates to be "just and reasonable," there exists a "zone of reasonableness" wherein rates can be neither "less than compensatory" nor "excessive."[8] Within the zone of reasonableness, a just and reasonable rate is high enough to "both maintain the producer's credit and attract capital," while low enough to prevent "exploitation", or an exercise of market power, by the pipeline.[9]

A primary impetus for the economic regulation of oil pipeline rates is that oil and NGL pipelines have many of the characteristics of a natural monopoly.[10] The economies of scope and scale associated with the operation of oil pipeline systems, as well as the significant fixed costs and time associated with entry or expansion, contribute to the barriers to entry: the ability of an incumbent pipeline to serve incremental demand from customers sooner and at lower cost than a new entrant creates circumstances where incumbents can deter entry.

However, in key respects, FERC's existing policies for granting market-based ratemaking authority and approving negotiated committed shipper rates fail to constrain oil pipeline rates to a zone of reasonableness consistent with optimal investment in capacity. Rather, these policies provide oil pipeline companies with the incentive and the opportunity to earn excessive profit by exercising market power through under-development of capacity.

B. Existing FERC Regulatory Policies That Incentivize the Exercise of Market Power

In oil and NGL transportation markets, market power exists when pipeline capacity is constrained and/or there is an insufficient number of alternatives competing with incumbent pipelines.[11] If pipeline capacity is constrained and barriers to entry limit the timely availability of competitive alternatives, shippers' willingness to pay for the existing capacity (or any potential incremental capacity) can exceed the underlying cost to provide that capacity, such that incumbent pipelines can charge committed shipper rates or market-based rates above competitive levels. As the Commission has correctly and succinctly summarized the concern, "[b]asic economic theory holds that firms with market power, like pipelines, will construct less capacity than competitive firms because doing so results in higher prices and profits."[12]

7. Farmers Union Cent. Exch. Inc. v. FERC, 734 F.2d 1486, 1501-02 (D.C. Cir. 1984) [hereinafter Farmers Union II].

8. *Id.* at 1502.

9. *Id.* (internal citation omitted).

10. U.S. DEP'T OF JUSTICE, OIL PIPELINE DEREGULATION, at iv (May 1986), https://www.ferc.gov/sites/default/files/2020-06/doj-report.pdf.

11. *See, e.g.*, David W. Savitski, *Price Tests for Market Power Analysis of Natural Gas Storage Providers*, 37 ENERGY L.J. 177, 184-85 (2016).

12. Order No. 712-A, *Promotion of a More Efficient Capacity Release Market*, 125 F.E.R.C. ¶ 61,216 at P 33 (2008) [hereinafter Order No. 712-A].

By contrast, in a competitive market with adequate alternatives and no constraints, sellers of capacity have a profit incentive to expand or enter when price exceeds their long-run marginal cost to provide capacity, such that competition among sellers of capacity drives the market price to the long-run marginal cost level. Thus, sound economics dictates that in context of analyzing whether a market is workably competitive, a reasonable proxy for a competitive rate should be based on an estimate of the long-run marginal cost of providing incremental transportation capacity, and competitive alternatives should be identified based on whether shippers *would* and *could* shift volumes to the alternatives in response to a rate increase by the subject pipeline above a competitive level.

Before approving market-based rates, FERC requires the applicant pipeline to demonstrate that adequate competitive alternatives exist in the relevant origin and delivery markets to discipline its potential to exercise market power, where such exercise consists of sustaining rates substantially above the rate levels that would be expected to persist in a workably competitive market.[13] However, following the economically flawed D.C. Circuit *Mobil Pipeline Co. v. FERC* decision,[14] the Commission issued a series of decisions that no longer identify competitive alternatives based on whether shippers *would* and *could* shift volumes to the alternatives in response to a rate increase by the subject pipeline above a competitive level.[15] Rather, the *Mobil* decision and FERC's subsequent *Seaway* decisions articulate a policy that presumes that any alternative currently observed to be "used" in the market is necessarily a competitive alternative (even if operating at capacity),[16] and that any prevailing commodity price locational differential associated with "used" alternatives represents a competitive *transportation* rate level, even if the prevailing commodity price locational differential significantly exceeds the underlying long-run marginal cost of providing the relevant transportation service.[17]

The economically unsound statements at the heart of this policy are in direct conflict with the Commission's own prior correct ruling—in the 1998 *Koch Gateway* decision—that competitive alternatives are appropriately identified in relation to a long-run competitive equilibrium wherein a competitive price level is "determined by the long-run marginal cost for the marginal supplier" of the transportation service in question.[18] Indeed, even in the flawed *Seaway II* decision, the Commission continued to correctly recognize that marginal cost is the relevant reference point for market power analysis.[19] Nevertheless, in the *Seaway* decisions

13. Order No. 572, *Market-based Ratemaking for Oil Pipelines*, F.E.R.C. STATS. & REGS. ¶ 31,007, 59 Fed. Reg. 59,148 (1994) [hereinafter Order No. 572].

14. Mobil Pipeline Co. v. FERC, 676 F.3d 1098 (D.C. Cir. 2012).

15. *Enterprise Products Partners L.P. and Enbridge Inc.,* 146 F.E.R.C. ¶ 61,115 (2014) [hereinafter *Seaway I*]; *order on reh'g*. 152 F.E.R.C. ¶ 61,203 (2015) [hereinafter *Seaway II*]. Note that there are additional FERC decisions issued following the *Seaway I* and *Seaway II* decisions that implement economically flawed analyses that are discussed in section III *infra*.

16. *Seaway I*, *supra* note 15, at P 56; *Seaway II*, *supra* note 15, at P 4.

17. *Seaway I*, *supra* note 15, at P 55.

18. *Koch Gateway Pipeline Co.*, 85 F.E.R.C. ¶ 61,013, at 61,045 (1998) [hereinafter *Koch Gateway*].

19. *Seaway II, supra* note 15 at P 30, Appendix at P 7.

and subsequent decisions, the Commission has ignored long-run marginal cost as the relevant indicator of a competitive price level. Instead, FERC implements a policy that effectively begins the evaluation of whether oil pipeline transportation markets are sufficiently competitive to prevent an exercise of market power by tautologically *assuming* that prevailing prices and "used" alternatives reflect the outcome of workable competition in the subject market. This fundamental flaw biases FERC's market power analyses toward indicating that markets are more competitive than they actually are—thereby permitting pipelines that possess market power to nevertheless charge market-based rates.

Under the Commission's current flawed policies, if a pipeline is applying for market-based rates, or has market-based rates, that pipeline is incentivized to under-develop capacity. In the case of a pipeline applying for market-based rates, if the applicant pipeline is constrained, shippers are likely to be using less attractive alternatives, such as rail, waterborne, or trucking, as an outlet to serve transportation demand in excess of the constrained pipeline capacity. Under the Commission's presumption that "used" alternatives are competitive alternatives, these lower quality or higher cost "used" alternatives would be deemed viable competitive alternatives and assumed to be setting a competitive rate level for the subject pipeline. However, such alternatives would not be *used* at all if there were adequate pipeline capacity being provided at a competitive price consistent with the long-run marginal cost to expand pipeline capacity and alleviate the constraint.

The tautological presumption that the observed usage of alternatives and the observed market prices of used alternatives necessarily reflect competitive outcomes is known as the "Cellophane Fallacy" (or sometimes the "Cellophane Trap"), so-named for a case involving DuPont's exercise of market power in raising the price for cellophane to the point that higher cost alternative wrapping materials became used substitutes in the market. The Cellophane Fallacy has been recognized by academics and the Commission as a logically flawed approach to identifying competitive alternatives when analyzing markets to evaluate the existence of market power.[20]

While FERC claims that the Cellophane Fallacy is unlikely to occur in the oil pipeline industry with regulated rates,[21] FERC's reasoning is unsound because it fails to account for the fact that the vast majority of FERC-jurisdictional oil pipeline tariff rates are not set on a cost-of-service basis and are not constrained to be reflective of costs. Ultimately, the Commission's approach is a kind of self-fulfilling prophecy: by asserting that its analyses are immune from the Cellophane Fallacy, FERC permits that very fallacy to influence the results in ways that reinforce the faulty presumption of immunity.

FERC's policies also facilitate the exercise of market power with respect to committed shipper contracts. When offering expanded capacity, pipelines can enter into contracts with shippers whereby a shipper will commit to ship a certain

20. *Id.* at PP 22-24; *see also* W. KIP VISCUSI, JOSEPH E. HARRINGTON, JR. & JOHN M. VERNON, ECONOMICS OF REGULATION AND ANTITRUST 297 (4th ed. 2005).

21. *See infra* section III.A.1.a.

volume at a specified rate. Within these committed contracts, pipelines often include a "duty to support" clause for committed shippers to support the initially filed rates and terms of service.[22] Despite this, FERC has stated it will not review the initial filing of negotiated committed shipper rates to evaluate whether the rates produce a reasonable (rather than excessive) return, even though it has acknowledged that the revenue generated by committed shipper contracts often far exceed the pipeline's underlying costs.[23] Thus, FERC's committed shipper rate approval policies effectively foreclose regulatory recourse for shippers desiring to ensure competitive rate levels – leaving them to negotiate in an environment where the pipeline party has no clear check on its ability to exercise market power.

C. Proposed Changes to Remedy the Incentive for Oil Pipelines to exercise Market Power

With respect to its analysis of market power when determining whether to grant (or continue to allow) market-based ratemaking authority, the Commission should not presume that all "used" alternatives are necessarily competitive in terms of price and availability, nor presume that the prevailing prices charged by alternatives and associated prevailing commodity price locational differentials determine competitive transportation rate levels for the subject pipeline.

Consistent with existing Commission practice, a netback price analysis in an origin market or a delivered price analysis in a destination market can be applied for evaluating shippers' willingness to shift volumes in response to a rate increase by the subject pipeline *above a competitive level*.[24] However, such an analysis will only provide a valid indication of whether potential alternatives are competitive in terms of price *if the competitive transportation price level incorporated into the analysis is reflective of the long-run marginal cost* to provide the relevant transportation service.

With respect to pipelines' incentive to obtain and exercise market power when negotiating committed shipper rates for new or expanded pipeline transportation services, the essential policy changes are ones that (i) give current or potential shippers the freedom to investigate whether the actual or proposed rates are at reasonable levels reflective of the pipelines' costs, and (ii) ensure that shippers have access to the information necessary to perform such assessments. If the Com-

22. *GT Pipeline, LLC*, 161 F.E.R.C. ¶ 61,066, at P 29 (2017) (citing *Colonial Pipeline Co.*, 146 F.E.R.C. ¶ 61,206, at P 32 (2014); *Nexen Mktg. U.S.A., Inc. v. Belle Fourche Pipeline Co.*, 121 F.E.R.C. ¶ 61,235, at PP 51-52 (2007)).

23. *Seaway Crude Pipeline Co.*, 146 F.E.R.C. ¶ 61,151 at PP 25-27 (2014).

24. When analyzing an origin market, a netback price is the effective commodity price received by a seller in the origin market by subtracting transportation cost from the destination commodity price. When analyzing a destination market, a delivered price is the effective commodity price received at a destination, determined by starting with an origin commodity price and adding the transportation cost from that origin to the destination. Comparing a netback price or delivered price attainable on a subject pipeline (after a rate increase above a competitive level) to the netback or delivered prices attainable via other transportation alternatives is the analysis that should be used to identify competitively priced alternatives that would be available to shippers to discipline an exercise of market power by the subject pipeline.

mission were to clarify that any duty to support clauses in committed shipper contracts do not foreclose the ability of shippers to challenge the reasonableness of the committed rates and require that pipelines include segmented cost of service data in their annual Form 6 filings, shippers would have the opportunity and ability to evaluate whether committed shipper rates are within a zone of reasonableness. Committed shippers would be in a position to balance the likelihood of a rate adjustment against their incurrence of litigation cost—just as shippers currently do for non-committed rates (when adequate cost information is available).

The remainder of this article proceeds as follows. First (in section II), we provide an overview of the economics of capacity decisions and the incentives to expand or contract capacity. Next (in section III), we examine the disincentive for capacity development created by FERC's existing policies and practices for granting market-based ratemaking authority and explain our recommendations for an economically sound approach to evaluating levels of competition to ensure that market base rates can only be charged by pipelines that truly lack market power in the relevant origin and destination markets. Finally (in section IV), we explain how FERC's existing policy toward committed shipper rates incentivizes oil and NGL pipelines to under-develop capacity and advance recommendations to alleviate this concern.

II. ECONOMICS OF OIL PIPELINE CAPACITY DECISIONS

A. Profit-Maximizing Output in Competitive and Uncompetitive Markets

A firm's profit maximizing output is determined by the additional cost incurred to produce additional output ("marginal cost") relative to the additional revenue received for selling the additional output ("marginal revenue").[25] If a firm's marginal cost is less than the marginal revenue it is earning at a given level of output, it will be profitable for that firm to increase output. Conversely, if a firm's cost to produce an additional unit of output exceeds the revenue it can earn from selling that unit (*i.e.*, its marginal cost exceeds marginal revenue), then incremental output reduces the firm's overall profits. Consequently, profit is maximized where marginal cost equals marginal revenue. Importantly, this is true both for "price taking" firms operating in competitive markets *and* for firms that possess and exercise market power in uncompetitive markets.[26]

All firms maximize profit where marginal cost equals marginal revenue, but the degree of competition in markets determines what price and output levels give rise to this profit-maximizing condition. While firms operating in a competitive environment maximize profit where their marginal cost equals the market price, firms operating in uncompetitive markets maximize profit by restricting their out-

25. PHILLIP E. AREEDA, HERBERT HOVENKAMP & JOHN L. SOLOW, ANTITRUST LAW: AN ANALYSIS OF ANTITRUST PRINCIPLES AND THEIR APPLICATION ¶ 503a at 115 (3d ed. 2007) [hereinafter Areeda *et al.*].

26. *Id.* at ¶ 503a.

put to a level where the market price *exceeds* their marginal cost. Firms in competitive markets are "price takers" because they have no agency to unilaterally raise their prices and must sell at the competitive market price or not at all. In competitive markets, equilibrium occurs with multiple price-taking firms each producing the levels of output that set their respective marginal costs equal to the market price.[27] By contrast, a firm with market power would lose *some*, *but not all* of its sales in response to an increase in the price it charges. Such a firm has an incentive to restrict its output below the competitive equilibrium level, thereby raising the market price it can charge for every unit it sells. Thus, a comparison of market price to marginal cost can indicate whether a firm is behaving competitively or exercising market power. Specifically, a clear separation of market price from marginal cost can indicate that a market participant is exercising market power.[28]

For oil and NGL pipelines, the *short-run* marginal cost (*i.e.*, the incremental cost of transporting an additional barrel) can be very low when existing capacity is not constrained,[29] and very high when serving an additional unit of product demand requires a capital-intensive expansion of capacity. As discussed further below, owing to this "capital indivisibility" characteristic of the oil pipeline industry, it is an examination of price in relation to *long-run* marginal cost[30]—including the incremental capital costs necessary to expand capacity and serve incremental demand—that permits determination of whether an oil or NGL pipeline is behaving competitively or exercising market power.

B. Market Incentives to Expand or Reduce Capacity

There are several incentives to expand or reduce oil and NGL pipeline capacity that are directionally common in both competitive and uncompetitive markets. Incentives to expand capacity include increases in market demand, decreases in long-run marginal costs, and the ability to enter into long-term contracts, as well as the incentive for low-cost incumbents to deter entry by potential competitors. Conversely, incentives for market participants to reduce capacity include decreases in market demand, increases in long-run marginal costs, and constraints on long-term contracting, as well as the ability of incumbent pipelines to exercise market power.[31]

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27. *Id.*

28. *Id.*

29. When capacity is not constrained, the short-run marginal cost of transporting one more barrel of product is the cost associated with additional fuel and power (and potentially drag-reducing agent).

30. A "long-run marginal cost" refers to the costs of providing incremental output over time horizons when all factors of production can be changed. A "short-run marginal cost" refers to the incremental cost of producing one more unit in the short-run, when factors of production are fixed. In the case of oil pipelines that charge a single rate to recover variable costs, as well as return of and on capital, it is long-run marginal costs that are relevant to be recovered in rates associated with changes in capacity. *See also* Areeda *et al.*, *supra* note 25, at p. 122-123 ¶ 504.

31. This section provides an overview of incentives to expand or reduce/restrict capacity and does not attempt to catalogue all potential incentives that may exist in particular markets.

An increase in market demand incentivizes increases in oil and NGL pipeline capacity, whether or not the transportation market is competitive. When pipelines have built capacity to a point where marginal revenue equals long-run marginal cost, an increase in market demand (meaning a greater quantity of transportation is demanded at every price level) will induce expansion of capacity because the willingness to pay for the existing transportation capacity will have increased.[32] Conversely, a decrease in market demand incentivizes oil and NGL pipeline to reduce capacity, whether or not the transportation market is competitive. When pipelines have built capacity to a point where marginal revenue equals long-run marginal cost, a decrease in market demand will cause the intersection of the marginal revenue curve and a pipeline's long-run marginal cost curve to move to a lower quantity (capacity) and price (rate) level.[33]

A decrease in long-run marginal cost provides an incentive to expand capacity, working in a similar manner to an increase in demand. When long-run marginal cost decreases (for example due to a decrease in the cost of line pipe materials for constructing an expansion), firms that had previously installed capacity up to a point where long-run marginal cost equated to marginal revenue would now be in a position where long-run marginal cost is less than marginal revenue, and hence would have an incentive to expand capacity. Conversely, an increase in long-run marginal cost provides an incentive to restrict capacity, working in a similar manner to a decrease in demand.[34]

Long-term contracting incentivizes capacity expansion by reducing the risk associated with capital investment to be recovered over a long, useful life. Committed shipper contracts are typically multi-year (or even multi-decade) commitments by customers to pay specified rates to transport specific monthly or annual volume levels. The ability for pipelines to obtain these types of long-term take-or-pay volume commitments provides some financial assurance that a pipeline entity will receive consistent revenue streams sufficient to recoup its invested capital and expect to earn at least a fair market rate of return over the economic life of the assets. This positively affects the pipeline's ability to secure financing and reduces the risk of the investment.[35]

32. Importantly, pipelines with market power *also* have an incentive to expand capacity when market demand goes up, since the increased willingness to pay means greater marginal revenue is obtainable for each unit of additional output. *Guttman Energy, Inc. v. Buckeye Pipe Line Co.*, 161 F.E.R.C. ¶ 61,180, at P 299 (2017) [hereinafter *Guttman*].

33. Areeda *et al.*, *supra* note 25, at ¶ 503a.

34. *Id.*

35. *See Express Pipeline P'ship,* 76 F.E.R.C. ¶ 61,245 (1996) (stating that "[u]ncommitted shippers do not provide the revenue assurances [. . .] that term shippers provide" and explaining that the amount of risk shifted from the pipeline to the term contract shipper increases with the length of the volume commitment). *See also Colonial Pipeline Co.*, 146 F.E.R.C. ¶ 61,206, at P 38 (2014) (acknowledging that volume guarantees in committed shipper contracts "create financial certainty" for the pipeline) and *North Dakota Pipeline Company LLC*, 147 F.E.R.C. ¶ 61,121, at P 22 (2014) (discussing how FERC's declaratory order process serves to remove regulatory uncertainty associated with the provision of proposed new service, thereby "allow[ing] an oil pipeline to obtain appropriate financing and/or move forward with its investment decisions").

Finally, incumbent pipelines may have an incentive to expand capacity when doing so can deter competition from potential new pipelines seeking to enter a transportation market. Oil and NGL pipeline have large economies of scale due to their high fixed costs and low variable costs, which causes average total costs to decline over the range of volumes up to the pipeline's capacity. Given these "natural monopoly" features of pipeline transportation,[36] an incumbent pipeline with excess capacity—or with the ability to engage in comparatively low-cost expansion projects[37]—can deter entry of potential alternative pipelines.[38]

C. Policy Implications of Market Incentives

It is certainly appropriate for FERC to be aware of legitimate incentives for oil and NGL pipelines to reduce or restrict capacity in response to market signals, and it is commendable that FERC permits pipelines and shippers to enter into long-term contracts in order to incentivize needed investment. However, FERC must also remain vigilant against the incentive some pipelines have to raise prices and restrict capacity due to their ability to exercise market power. As discussed above, the profit-maximizing capacity decision for a firm with market power is to reduce or restrict capacity below levels that would prevail in a competitive market.[39]

When pipeline capacity is constrained, shippers' willingness to pay for transportation is determined by the commodity price differential between the pipeline's origin and destination, which can be significantly greater than both the pipeline's average total cost and its long-run marginal cost to expand capacity.[40] When the market value of transportation persists at levels greater than long-run marginal cost, it is both (i) a signal that an expansion of capacity is warranted, and (ii) a

36. Declining average total costs is a primary characteristic of "natural monopoly," where there are lower total costs for a single firm to provide total industry output than multiple firms. W. KIP VISCUSI, JOSEPH E. HARRINGTON, JR., AND JOHN M. VERNON, ECONOMICS OF REGULATION AND ANTITRUST at 337-339 (3rd ed. 2001).

37. In typical circumstances, an incumbent pipeline can add capacity more cheaply than a potential new-build pipeline, since the incumbent can increase flow rates by augmenting pumping facilities or making other incremental improvements, while a new entrant must install line pipe and pumping stations.

38. Avinash Dixit, *The Role of Investment in Entry Deterrence*, 90 ECON. J. 95 (1980) at 98-99. *See also* VISCUSI, *supra* note 36, at 178-82. Note that, in the situation described, even if a pipeline is operating at its chosen capacity that deters entry of rival firms, output will be lower than the level that would occur in a competitive market and price will be higher than the level that would occur in a competitive market.

39. Areeda *et al*., *supra* note 25, at ¶ 501.

40. Note that when seasonal variations cause commodity price differentials to exceed long-run marginal cost in certain periods but not in others, these circumstances *could* be consistent with a workably competitive market. *Explorer Pipeline Co.*, 87 F.E.R.C. ¶ 61,374, at p. 62,394. However, more typically in oil and NGL transportation markets, situations of constrained capacity or excess capacity persist over longer periods of time as transportation demand responds to longer-term shifts in commodity market conditions. For example, the demand for pipeline transportation of crude oil from a producing basin is unlikely to be seasonal. Instead, overall demand is dependent on whether drilling (and associated production) is increasing or decreasing in response to long term commodity price fluctuations relative to the cost of production.

sufficient *incentive* for market participants to expand and serve incremental demand. Competition among numerous sellers of transportation capacity is the market mechanism that drives competitive rates to the level of long-run marginal cost.

However, because pipeline capacity expansion is inherently slow, transportation rates that are able to persist at levels above long-run marginal cost represent a valid market power concern. Barriers to entry—primarily stemming from the necessity of large capital investments (referred to as "extremely high sunk costs" in *Farmers Union II*)—are a source of market power in the oil pipeline industry and a major impetus for economic regulation of oil pipeline rates.[41] Without barriers to entry, it would be difficult to sustain a price increase above a competitive price level, and any basis for price regulation would be significantly lessened.[42] But given the high barriers to entry and other natural monopoly characteristics of the oil pipeline industry, it is essential that FERC adopt and apply regulatory policies that are effective at preventing the exercise of market power and constraining pipeline rates to fall within a zone of reasonableness indicative of the long-run marginal cost to provide oil and NGL pipeline transportation service.

D. Reasonable Regulatory Policy for Incentivizing Capacity Levels that Would Occur in Competitive Markets

As explained above, for oil and NGL pipelines, it is a comparison of prevailing price to long-run marginal cost that is relevant for determining whether a pipeline is behaving competitively or exercising market power. Thus, comparing rates that are charged (or could be charged) by a given oil pipeline to an estimate of the long-run marginal cost for the transportation service in question is a reasonable regulatory policy for incentivizing capacity levels that would occur in competitive markets, even in situations where an entity may possess market power.[43]

Notably, this principle is already embedded in certain aspects of the Commission's economic regulation of pipelines. For example, when pipelines and shippers pre-negotiate committed rates associated with expansion and greenfield pipeline projects, the committed (and uncommitted) rates for which FERC approval is sought are structured to provide for recovery of the incremental capital costs associated with the expansion project.[44] Accordingly, these negotiated rates necessarily represent a price level that is *at least* equal to (and may be greater than) the long-run marginal cost of the expansion project, otherwise pipeline companies

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41. *Farmers Union II*, 734 F.2d at 1509 n.51.

42. As discussed in Areeda *et al.*, *supra* note 25, at ¶ 420a.

43. ALFRED E. KAHN, 1 THE ECONOMICS OF REGULATION 160-161 (7th prtg. 1998) (1970-71). *See also* Order No. 572, *supra* note 13, at 31,180 (quoting Tejas Power Corp. v. FERC, 908 F.2d 998, 1004 (D.C. Cir. 1990)).

44. *See e.g.*, *Express Pipeline P'ship*, 76 F.E.R.C. ¶ 61,215 (1996); Petition for Declaratory Order or Seaway Crude Pipeline Company LLC, FERC Docket No. OR13-10-000, Attachment 2 at P 3 (Dec. 10, 2012) ("Seaway requests that the FERC consider and approve this Petition as soon as possible, as Seaway must make imminent decisions regarding whether to make hundreds of millions of dollars in additional capital investments to continue expanding the Seaway Pipeline.").

would not agree to go forward with development on the basis of the pre-negotiated rates. In addition, regulated rates based on cost of service are designed to approximate a long-run competitive rate, which is tied to long-run marginal cost.[45] As the D.C. Circuit noted in *ExxonMobil*, "[i]t is certainly reasonable for FERC to use a cost-of-service computation as an approximation for a pipeline's economic circumstances; the purpose of a cost-of-service rate, after all, is to simulate what a pipeline's economic behavior would be in a competitive market."[46]

When it originally established the regulations governing market based rates for oil pipelines, FERC properly recognized the central role of long-run marginal cost in determining a reasonable proxy for a competitive rate:

> In a competitive market, where neither buyer nor seller has significant market power, it is rational to assume that the terms of their voluntary exchange are reasonable, and specifically to infer that the price is close to marginal cost, such that the seller makes only a normal return on its investment.[47]

In this context, the reference to the competitive price being "close to marginal cost, such that the seller makes only a normal return on its investment" refers to a *long-run* competitive price that includes a "normal" fair market rate of return on invested capital in addition to the return of capital and recovery of incremental operating cost.[48]

In the *Seaway II* decision, the Commission correctly reiterated the relevance of long-run marginal cost in determining a competitive rate, stating that "for purposes of the market power analysis, the Commission uses the marginal costs of the marginal supplier"[49] and that "[o]nly actual costs are relevant under the Commission's methodology, and the burden is on the applicant to demonstrate that the costs utilized in its application for market-based rate authority are actual costs, and not those set above the marginal cost of the marginal supplier, by any means."[50] These statements are consistent with its earlier *Koch Gateway* decision, which unequivocally stated, "[a]n appropriate base price in a market power evaluation of this type is the long-run competitive price. The long-run transportation price between given points in a competitive market will be determined by the long-run

45. *SFPP, L.P.*, 121 F.E.R.C. ¶ 61,240, at P 14 (2007) ("[C]ost-of-service rate making seeks to replicate a competitive rate. Since under competition firms set their prices to recover costs, including a reasonable return, a regulated rate is designed to replicate that competitive situation. Thus it is reasonable to view a rate in a cost context even if negotiation or other market factors were involved in constructing the rate.").

46. *ExxonMobil Oil Corp. v. FERC*, 487 F.3d 945, 961 (D.C. Cir. 2007). Note what while a competitive rate will be independent of the vintage of the assets owned by any specific competitor, over the long run such a rate must still provide a level of return sufficient to reasonably compensate the owner for its investment in the assets. Thus, a competitive rate may be expected to involve a different pattern of capital recovery over time compared to a cost-of-service based rate, but both will be expected to produce a net present value of cash flows equal the capital investment.

47. Order No. 572, *supra* note 13, at 31,180 (quoting *Tejas Power Corp.*, 908 F.2d at 1004).

48. *Seaway II, supra* note 15, at P 44. ("[t]he Commission will not utilize a tariff rate that does not include expansion costs as a competitive price proxy when the appropriateness of such a proxy relies on the occurrence of expansion at the tariff rate.")

49. *Id.* at Appendix P 7.

50. *Id.* at P 30 (footnote omitted).

marginal cost for the marginal supplier of building and operating transportation facilities. . . ."[51]

Thus it should not be considered controversial that an evaluation of oil pipeline transportation rates in relation to the long-run marginal cost of providing the transportation service in question is the appropriate basis for determining whether rates reflect competitive behavior or not. However, as discussed in sections III and IV below, certain aspects of FERC's current policies and practices concerning market-based rates and committed rates have diverged from (and are not consistent with) the fundamental economic principles that were previously recognized by the Commission. In the remainder of this article, we describe the deficiencies in FERC's current approach and explain how they can be remedied by using established techniques for estimating long-run marginal cost to provide relevant evidence of whether prevailing or applied-for tariff rates for oil and NGL pipelines reflect competitive levels.

III. FERC'S POLICY TOWARD MARKET-BASED RATES INCENTIVIZES OIL AND NGL PIPELINES TO EXERCISE MARKET POWER AND UNDER-DEVELOP CAPACITY

As discussed above, the Commission's current policies are logically flawed in that they presume competitive circumstances prevail when the Commission's goal is to evaluate whether the markets in question are sufficiently competitive to discipline an exercise of market power. Specifically, in *Seaway I*, the Commission began a policy of presuming that any "used" alternatives are necessarily competitive alternatives.[52] Further, following the same flawed reasoning, when evaluating whether a given alternative is competitive in terms of price, the Commission defines the competitive transportation rate to be one that would equate the subject pipeline's netback price to the lowest netback price (in origin markets) or equate the subject pipeline's delivered price to the highest delivered price (in destination markets) provided by a "used" alternative.[53]

These presumptions are economically unsound because if a pipeline with market power is operating at capacity, shippers are likely to be using higher-cost alternatives (such as rail or waterborne transportation), even though the subject pipeline (or other pipelines in the market) could profitably expand and displace those higher cost alternatives. If such a pipeline is permitted to charge market-based rates—which rates may exceed its or other similar pipelines long-run marginal cost of expansion—the pipeline will be incentivized to withhold expansion capacity in an exercise of its market power.[54] In that case, the underdevelopment

51. *Koch Gateway*, *supra* note 18, at p. 61,045.

52. *See Seaway I*, *supra* note 15, at P 76.

53. *Id.* at P 56; *Seaway II, supra* note 15, at P 34 (note that Dr. Arthur provided testimony in this docket on behalf of Continental Resources, Inc., Husky Marketing and Supply Company, Suncor Energy Marketing, Inc., and Canadian Natural Resources Limited).

54. *Seaway II*, *supra* note 15, at P 45. When a pipeline that *could* profitably expand chooses not to do so, that is functionally equivalent to restricting the capacity available in the market, thereby permitting uncompetitive higher cost alternatives to serve marginal transportation demand and set the market-clearing price. In other words, in these circumstances, the choice not to expand (or expand by an amount less than the amount that would be demanded at a competitive rate level) may represent an exercise of market power.

of capacity will result in incumbent pipelines earning supranormal profits by charging supracompetitive transportation rates. Meanwhile shippers are forced not only to pay the incumbent pipeline's excessive rates, but also to use higher cost transportation alternatives in lieu of more efficient pipeline expansion capacity that is being withheld.

To remedy the current incentive for incumbent pipelines to exercise market power and under-develop capacity, we recommend that the Commission cease its current practice of tautologically presuming that existing market outcomes (including prices, locational commodity price differentials and "usage" of alternatives) reflect competitive circumstances when trying to evaluate whether market power exists. Rather, a reasonable proxy for a competitive transportation rate in a market power analysis should be based on an estimate of the long-run marginal cost of providing incremental transportation capacity, and competitive alternatives should be identified based on whether shippers would and could shift volumes to the alternatives in response to a rate increase by the subject pipeline above a competitive level. Specifically, to evaluate shippers' willingness to shift to potential alternatives in response to a rate increase above a competitive level—and thus, whether an alternative should be considered competitive—a netback analysis (in an origin market) or a delivered price analysis (in a destination market) can be applied based on the *appropriate competitive rate level estimated based on long-run marginal cost*. In addition, the Commission should clarify that only alternatives that are available to receive volumes diverted from a subject pipeline should be considered competitive alternatives. These clarifications and changes to the Commission's current policy would work to ensure that market-based rates are charged only where truly competitive transportation alternatives exist, thereby mitigating the potential for abuse of market power.

A. *Overview of FERC's Existing Policy for Market-Based Rates*

The primary methodology utilized by the Commission for assessing market power is a structural analysis that infers the presence of market power from indirect evidence about the number of competitors in a market.[55] In such an analysis, the presence of few competitors and a high degree of difficulty for entry provides indirect evidence that an incumbent firm possesses market power. The Commission requires oil and NGL pipelines applying for market-based rates to define the relevant product and geographic markets—both origin and destination markets—in which the pipeline seeks to show that it lacks significant market power.[56] Once relevant markets are defined, competitive alternatives are identified in order to make an inference whether adequate competitive alternatives exist such that the subject pipeline lacks significant market power.[57]

55. Order No. 572, *supra* note 13.
56. *Id.* at 31,187-89.
57. *Id.* at 31,191.

As discussed above, the Commission's current policies toward defining relevant markets and identifying competitive alternatives were first delineated in *Seaway I* and *Seaway II,*[58] following a decision regarding a market-based rates application by the D.C. Circuit *Mobil* decision.[59] With respect to identifying competitive alternatives to the subject pipeline, the Commission states that alternatives must be competitive in terms of availability, quality, and price, stating:

> For an alternative to be competitive, it must possess the ability to discipline, or prevent, a potential increase in price above the competitive level by the pipeline applicant. A competitive alternative also must be available to receive product diverted from the applicant in response to a price increase, and must be of the same quality as the applicant. *Mobil* did not alter this analysis.[60]

This criteria for identifying competitive alternatives to a subject pipeline makes economic sense in that in order to a discipline a rate increase above a competitive level by the subject pipeline, shippers on the subject pipeline *would* and *could* shift volumes from the subject pipeline to an alternative transportation provider. The "would" part of this concept is that the alternative is competitive in terms of price and quality. The "could" part is that the alternative is competitive in terms of availability. As the Commission previously recognized:

> If an alternative source has not been shown to be a good alternative, it should not be included in the relevant geographic market and used in market share, HHI, or other market power statistics. Such statistics are meaningless if all of the alternatives are not good alternatives.[61]

In Order No. 572 the Commission indicated that, in general, delivered prices—not transportation rates—should be compared to determine good, competitive alternatives in terms of price to a subject pipeline in a destination market. The Commission stated:

> [W]here competitive alternatives constrain the applicant's ability to raise transport prices, the effect of such constraints is ultimately reflected in the price of the commodity transported. Hence, the delivered commodity price (relevant product price plus transportation charges) generally will be the relevant price to be analyzed for making a comparison of the alternatives to a pipeline's services.[62]

For origin markets, the Commission has previously stated that netback prices (destination prices less transportation rates) should be compared for purposes of determining which alternatives are competitive alternatives in terms of price.[63] However, in *Seaway I*, the Commission effectively abandoned this principle, stating that netback price analyses for origin markets (analogous to delivered price analyses for destination markets) are not required to identify competitive alternatives in terms of price. Rather, *Seaway I* posits that "[u]sage [. . .] becomes the

58. *Seaway I, supra* note 15, at P 56; *Seaway II*, *supra* note 15, at P 34.

59. *Mobil*, 676 F.3d at 1105.

60. *Seaway I, supra* note 15*,* at P 45 (footnote omitted).

61. *TE Products Pipeline Co., L.P.*, 92 F.E.R.C. ¶ 61,121, at p. 61,467 (2000).

62. Order No. 572, *supra* note 13, at 31,189.

63. *Magellan Pipeline Company, L.P.*, 132 F.E.R.C. ¶ 61,016, at P 35 (2010) (footnotes omitted) (note that Dr. Arthur provided testimony in this docket on behalf of Frontier Oil and Refining Company).

necessary 'proxy' for determining whether an alternative is in fact a good alternative."[64] In this context, the Commission's current policies of presuming (i) that all "used" alternatives are automatically competitive alternatives in terms of price, availability, and quality, and (ii) that a competitive price level is necessarily reflected in prevailing commodity price differentials, lead to alternatives that are not in fact competitive being included in market power statistics. In turn, the inclusion of uncompetitive alternatives in market concentration calculations biases the market power statistics toward a finding of adequate competition, even when the subject pipeline actually possesses significant market power.

1. Economic Flaws in FERC's Current Policy for Identifying Competitive Alternatives

a. The Cellophane Fallacy in Presuming "Used" Alternatives Are Competitive

The assumption that "used" alternatives, *i.e.*, those alternatives that consumers have demonstrated a willingness to substitute to at *prevailing* price levels, are necessarily competitive alternatives, is a recognized error known as the Cellophane Fallacy. This name refers to the Supreme Court's decision in *United States v. E.I. du Pont de Nemours & Co.*, 351 U.S. 377 (1956), wherein the Court upheld a finding that cellophane was sold in a competitive market because "[c]ellophane was indeed a close substitute for other wrapping materials at the going price for cellophane."[65] However, the market power analysis presented to the Court was flawed because it failed to recognize that "cellophane's price contained a monopolistic margin over its marginal cost."[66] In presuming that the prevailing price for cellophane represented a proxy for the competitive price, the market power analysis had failed to account for the fact that "[a] rational monopolist would, in fact, raise price until its product became a substitute for alternatives."[67]

Basic economic principles dictate that a firm with market power will increase its price until enough consumers are *just* becoming willing to substitute away from using a service. Thus, there can appear to be competitively priced substitutes when prices in a market reflect an exercise of market power, whereas if incumbent firms were charging a price close to a competitive level (a price reflective of the underlying cost of providing the service),[68] consumers would be unwilling to substitute

64. *Seaway I*, *supra* note 15, at P 56. *See also White Cliffs Pipeline, L.L.C.*, 173 F.E.R.C. ¶ 61,155, at P 52 (2020) (note that Dr. Arthur provided testimony in this docket on behalf of ConocoPhillips Company, HighPoint Resources Corporation, Kerr McGee Oil & Gas Onshore, LP, and Noble Energy, Inc.).

65. W. KIP VISCUSI, JOSEPH E. HARRINGTON, JR., AND JOHN M. VERNON, ECONOMICS OF REGULATION AND ANTITRUST 297 (4th ed. 2005).

66. *Id.*

67. *Id.*; *See also* Areeda *et. al.*, *supra* note 25, ¶ 539 at 300 ("[I]n seeking out a profit-maximizing price, the monopolist or oligopoly finds a price so high that a yet further price increase would be unprofitable because too many sales would be lost. As a result, cross-elasticity of demand is high when prices are already monopolistic.")

68. *See supra* section II.A.

away in response to a small but significant increase in price above the *competitive* price level. Hence, as succinctly explained by Professors Viscusi, Vernon, and Harrington, to avoid falling prey to the Cellophane Fallacy, "substitutes in consumption should be evaluated at prices that are reasonably close to marginal costs."[69]

Thus, usage does not demonstrate that an alternative is competitively priced, because that usage could be the result of a market price being charged by the subject pipeline that is above a competitive level. This is precisely the Cellophane Fallacy," as the Commission has recognized.[70] Yet, despite the clear economic principles dictating that "a high degree of substitution by consumers between two products must exist *at competitive prices* for the two products to be placed in the same market,"[71] the Commission continues to presume that all alternatives observed to be "used" at *prevailing* market prices should be treated as competitive alternatives in terms of price.

The Commission *has* correctly recognized in certain instances that the possibility of the Cellophane Fallacy means that automatically treating "used alternatives" as competitive is not valid when existing rates may be above competitive levels.[72] However, the Commission has failed to consistently apply this principle.[73] FERC has held (wrongly in our opinion) that there is a low likelihood of the Cellophane Fallacy arising as part of its methodology for evaluating market based rate applications, for two reasons. First, the Commission alleges an entity *seeking* market-based rates would not be able to charge rates above a competitive level.[74] Second, the Commission has argued that "if an unregulated monopolist did exist in the market, and such monopolist charged a monopoly price so that alternatives charging supra-competitive prices would be "used" in the market, the Commission's methodologies concerning market shares and market calculations would effectively capture such a scenario and reflect a non-competitive market".[75] Both of these rationales for minimizing concerns of the Cellophane Fallacy are seriously flawed.

The Commission's first assumption—that an applicant pipeline would not have the ability to exercise market power—is flawed because the vast majority of liquids pipeline rates are set by negotiation or indexing of prior non-cost-based rates. Indeed, FERC Staff recently calculated that only 1% of oil pipeline rate

69. VISCUSI, *supra* note 65, at 326.

70. *Seaway II*, *supra* note 15, at PP 22–24.

71. W. KIP VISCUSI, JOSEPH E. HARRINGTON, JR., AND JOHN M. VERNON, ECONOMICS OF REGULATION AND ANTITRUST at 261 (3rd ed. 2000) (emphasis added).

72. *Guttman*, *supra* note 35, at P 125 (note that Dr. Arthur provided testimony in this docket on behalf of Guttman Energy Inc. and PBF Holding Company LLC).

73. Put simply, whenever a capacity-constrained pipeline is applying for (or already charging) market-based rates, shippers are likely to be using higher cost alternatives that would not necessarily be used if there were adequate pipeline capacity being provided at a competitive price.

74. *Seaway II, supra* note 15, at PP 27-29.

75. *Id.*

changes were based on cost of service.[76] Consequently, there can be no assurance, and certainly no presumption, that oil pipeline rates reflect competitive levels tied to the underlying cost of providing service.[77] The Commission's second assumption—that its prescribed market share and concentration calculations would reveal an entity exercising market power—amounts to circular logic. If the Commission persists in assuming that "used" alternatives are competitive and that prevailing prices reflect competitive levels—precisely the two conditions that lead to the Cellophane Fallacy[78]—its market share and concentration analysis will tend to include alternatives that may not actually represent good alternatives when evaluated relative to true cost-reflective competitive price levels.[79] Thus, the Commission's approach is a self-fulfilling prophecy: by asserting that its analyses are immune from the Cellophane Fallacy, it permits that very fallacy to influence the results in ways that reinforce the faulty presumption of immunity.

b. Flaw in Presuming Constrained Alternatives Can Discipline a Rate Increase Above a Competitive Level

The Commission's current policy regarding whether an alternative is competitive in terms of availability is that "the Commission has found that inclusion of used alternatives is permitted even if such alternatives are being used to their full capacity"[80] and further that "the market share of an alternative also should not be excluded if it is at full capacity."[81] This treatment of any alternative operating at capacity as a valid competitive alternative to a subject pipeline is economically flawed and inconsistent with the Commission's own prior statements. As the Commission correctly recognized, "[a] competitive alternative also must be available to receive product diverted from the applicant [subject pipeline] in response to a price increase."[82] A monopolist is able to profitably sustain a rate increase

76. FERC Staff calculated that 81% of oil pipeline rate changes were made pursuant to indexing, 18% were made pursuant to negotiated settlement rates or market-based rates, and 1% were made pursuant to cost of service-index. Rick Smead, *Now Here You Go Again – FERC Prepares to Slash the Liquids Pipeline Rate Index*, RBN ENERGY (June 21, 2020), https://rbnenergy.com/now-here-you-go-again-ferc-prepares-to-slash-the-liquids-pipeline-rate-index.

77. Indeed, given that mitigating potential market power concerns for entities with natural monopoly characteristics is the primary basis on which the rates of liquids pipelines are subject to economic regulation, it would be more reasonable to presume the opposite—that existing rates set by negotiation or other non-cost-based means *do not* reflect competitive levels.

78. W. KIP VISCUSI, JOSEPH E. HARRINGTON, JR., AND JOHN M.VERNON, ECONOMICS OF REGULATION AND ANTITRUST 297 (4th ed. 2005).

79. In turn, inappropriately expanding the market definition to include Cellophane Fallacy alternatives that give the false appearance of being competitively priced may cause the market share and HHI statistics to falsely indicate an unconcentrated market.

80. *White Cliffs Pipeline, L.L.C.*, 173 F.E.R.C. ¶ 61,155, at P 52 (2020) (note that Dr. Arthur provided testimony in this docket on behalf of ConocoPhillips Company, HighPoint Resources Corporation, Kerr McGee Oil & Gas Onshore, LP, and Noble Energy, Inc.).

81. *Id*.

82. *Seaway I*, *supra* note 15, at P 45 ("[a] good alternative is an alternative that is available soon enough, has a price that is low enough, and has a quality high enough to permit customers to substitute the alternative for

above a competitive level because there are no alternatives for shippers to shift volumes to in response to a rate increase above a competitive level. Similarly, a subject pipeline with all alternatives operating at capacity would also be able to profitably sustain a rate increase above a competitive level because shippers could not shift volumes to the alternatives in response to a rate increase above a competitive level.[83] Just as alternatives that shippers *would not* switch to (because they are not competitive in terms of price or quality) should be excluded from market power statistics, alternatives that shippers *could not* switch to (*i.e.,* alternatives that not available) should likewise be excluded.

2. Economic Flaws in FERC's Current Policy for Identifying a Proxy for a Competitive Rate Level

In a delivered price or netback price analysis, an appropriate competitive price proxy is required in order to identify alternatives—either "used" or "unused"—that would be competitive with the subject pipeline if the subject pipeline were to implement a small but significant and non-transitory increase in price *above a competitive level* (SSNIP test). As mentioned above and explained further below,[84] the fundamental principle relevant for determining a reasonable proxy for a competitive rate is that competition drives prices to the level of long-run marginal cost to provide the service in question. However, according to its current policy, the Commission contends that "the appropriate proxy for a competitive price is one that recognizes the marginal supplier: the supplier providing the lowest netback in the market."[85] Unfortunately, as revealed in the following quote from the Commission's *Seaway I* decision, this approach to determining a competitive *transportation* rate confuses the relationship of netback *commodity* prices with transportation rates and is also erroneously grounded in the presumption that all "used" alternatives are competitive.

> In a market, the competitive price will be the netback of the alternative that provides the lowest netback among used alternatives (the "marginal netback"). Shippers in this market will seek to earn the highest netback among available alternatives, and will use the alternative with the highest netback until it no longer offers capacity. Shippers will then seek to ship on the alternative offering the next highest netback, and so on until the marginal netback is reached. **The marginal netback is the lowest netback generated among used alternatives. Thus, all used alternatives produce netbacks**

Koch Gateway Pipeline Company's ("Koch Gateway") service. In addition, to constrain Koch Gateway's exercise of market power, the alternative must be available in sufficient quantity to make Koch Gateway's price increase unprofitable.") (citing *Koch Gateway*, *supra* note 18).

83. PHILLIP E. AREEDA, HERBERT HOVENKAMP, & JOHN L. SOLOW, ANTITRUST LAW: AN ANALYSIS OF ANTITRUST PRINCIPLES AND THEIR APPLICATION ¶ 507b at 111 (2d ed. 2002) ("[t]he more elastic the demand a firm faces, the less market power it has. This particular demand – that is, the demand facing the individual firm rather than the demand facing the entire market – is called *residual demand*, which is defined as the entire *market demand* minus the *production* of all other producers.") If existing alternatives are unavailable such that shippers *could not* switch to them in response to a rate increase by the subject pipeline, the residual demand facing the subject pipeline is inelastic, indicating it possesses market power.

84. *See infra* section III.B.

85. *Seaway II*, *supra* note 15, at P 40.

> **at or above the marginal netback and are therefore competitively priced.** The key is that nothing being used offers a negative netback, or was unprofitable to the shipper.[86]

As discussed in the preceding section, in the presence of market power, it may be the case that higher cost "used" alternatives are only used *because* lower-cost incumbent suppliers are exercising their market power by withholding capacity in order to raise the market price. Ultimately, it is the long-run marginal cost at which lower-cost providers could *expand capacity to increase their market shares*—not the prices charged by higher cost alternatives that may be "used" in response to inadequate low-cost supply—that determines what price would be expected to prevail in a competitive market. Thus, by concluding that the lowest "used" netback commodity price (or highest "used" delivered commodity price) provides a valid basis for determining a proxy for the competitive transportation rate, FERC risks falling victim to the Cellophane Fallacy. However, this is just one of several logical flaws in the Commission's reasoning (and that of the D.C. Circuit Court's *Mobil* decision) that underlies its current policy for determining a competitive price proxy.

a. Flawed Reliance on Commodity Price Differentials Associated with "Used" Alternatives Providing Differentiated Services

First, the Commission's approach of treating marginal netback (or delivered) *commodity* prices as indicative of the costs associated with supplying the transportation in question is not valid if the marginal commodity netback (or delivered) price is associated with an alternative providing a *differentiated* service. For example, when an alternative is providing transportation between different origins and destinations than those served by the subject pipeline, or when an alternative is not providing transportation service at all (such as selling crude oil in a basin as an alternative to transporting crude oil out of the basin), the netback (or delivered price) associated with that alternative does not provide any relevant information about marginal cost of providing transportation service *between the specific origin and destination markets* in question. Put simply, differentiated transportation services have different cost structures. So, while transporting the commodity in question to or from different markets (than those served by the subject pipeline) or pursuing non-transportation alternatives to market the commodity *may* represent valid competitive alternatives (if they are indeed competitive in terms of quality, availability, and price) for inclusion in a market concentration analysis, they should *not* be treated as providing meaningful information about the marginal cost of the transportation service in question.

Further, the Commission has in the past correctly recognized that the commodity price differential between an origin and a destination does not necessarily

86. *Seaway I*, *supra* note 15, at P 55 (emphasis added; footnotes omitted); *see also Enterprise TE Products Pipeline Company LLC*, 146 F.E.R.C. ¶ 61,157, at P 19 (2014) (note that Dr. Arthur provided testimony in this docket on behalf of Chevron Products Company, HWRT Oil Company, LLC, Phillips 66 Company, and Murphy Oil Corporation).

reflect a competitive *transportation rate* between that origin and destination (even if commodity markets at the origin and at a destination may be independently competitive with large numbers of buyers and sellers). This is because an exercise of market power by an incumbent transportation provider can increase the commodity price differential between locations above a competitive level.[87] Intuitively, the prevailing average commodity price differential, the origin and destination of a subject pipeline's transportation service represents the implicit "value" to a shipper of transporting the commodity between those points.[88] Thus, simply put, the Commission has correctly recognized that the prevailing *value* of transportation between two locations does not necessarily represent a competitive transportation rate between those two points.[89]

Despite this, the Commission's current policy for determining a competitive *transportation* rate, as embodied in the passage from *Seaway I* quoted above, focuses on exactly these differences in netback (or delivered) *commodity* prices that represent the value of transportation between two locations.[90] In our opinion, this Commission precedent, which erroneously mandates the use of commodity price netback or delivered price differentials to establish a competitive transportation rate,[91] is both incorrect and irreconcilable with the Commission's correct statements in *Koch Gateway* and *Seaway II* regarding the relevance of marginal *transportation* costs for determining competitive *transportation* rate levels.

In *Seaway II,* the Commission clearly articulated that cost data for determining marginal cost is relevant in a market power analysis, stating that "[a] true and accurate market picture is derived by following basic economic and competition principles, which require that a competitive price proxy be based on the costs of the marginal supplier."[92] Further, in *Koch Gateway* (quoted above) the Commis-

87. *Natural Gas Pipeline Negotiated Rate Policies and Practices*, 114 F.E.R.C. ¶ 61,042, at PP 3–10 (2006) ("a pipeline charging negotiated rates tied to basis differentials could increase its revenues by withholding capacity in order to increase the relevant basis differentials. The Commission concluded that pricing mechanisms that invest pipelines with an incentive to use market power to manipulate the commodity price of gas would hinder the Commission's attempt to maintain and improve the competitive natural gas market."), *reh'g and clarification denied*, 114 F.E.R.C. ¶ 61,304 (2006); *Koch Gateway, supra* note 18, at 61,045 ("The long-run transportation price between given points in a competitive market will be determined by the long-run marginal cost for the marginal supplier of building and operating transportation facilities –not by the difference in short-term gas spot prices between various points. Gas spot price differentials at a given time could be above the long-run marginal cost of providing transportation between the points. A monopoly pipeline could charge transportation prices based on gas spot price differentials between selected points that would be above the long-run competitive transportation price.").

88. This is intuitive, since the locational price differential represents the incremental commodity value realized by selling at the destination rather than the origin. *See generally Seaway II*, *supra* note 15, at P 30.

89. *Seaway II*, *supra* note 15, at P 30.

90. *Seaway I, supra* note 15, at P 55, 69.

91. *See, e.g., Guttman*, *supra* note 32, at PP 128, 141 and *Guttman Initial Decision*, 155 F.E.R.C. ¶ 63,008, at P 203 (2016); *see also Seaway Crude Pipeline Co. LLC*, 157 F.E.R.C. ¶ 63,024, at P 22.

92. *Seaway II*, *supra* note 15, at Appendix P 6; see also *id*. at P 30 ("[T]he Commission in the Order on Rehearing held that the competitive price is the marginal cost of the marginal supplier, not the prevailing price.

sion clearly identified that it is the marginal supplier of the *same or similar transportation* service whose marginal cost determines the competitive rate level for that transportation service.[93] These economically sound rulings by the Commission contradict the Commission's post-*Mobil* statements and policy that erroneously support using differences in commodity prices or prevailing tariff rates as to determine a competitive rate level for the transportation service provided by a given subject pipeline.

The Commission's current flawed policy of treating the market value of transportation measured using prevailing netback or delivered commodity price differentials as determinative of the competitive transportation rate is built upon, what is, in our opinion, a fundamental economic error committed in the D.C. Circuit's decision in *Mobil*.[94] In *Mobil* (which was issued in 2012 and preceded FERC's *Seaway I* and *Seaway II* decisions), the D.C. Circuit Court concluded that a competitive rate level for Mobil's Pegasus pipeline was above its existing tariff rate level because the market value of the transportation service, as determined by the differential of the prevailing commodity price levels between the origin and destination of the transportation service, exceeded the prevailing tariff rate. The Court stated:

> As FERC's expert staff explained, the [Commission's SSNIP analysis performed using Pegasus's regulated rate] demonstrates only that Pegasus's regulated rate is below the competitive rate. The regulated rate does not reflect Pegasus's full value to Western Canadian crude oil producers and shippers. Therefore, the possibility that the market rate might be higher than the regulated rate does not show that Pegasus possesses market power.[95]

Unfortunately, the D.C. Circuit's *Mobil* decision fell into the Cellophane Fallacy when it assumed that market values and/or market clearing rates for transportation reflected a competitive level without any examination of what an actual competitive price level for the transportation service at issue would be.[96] The *Mo-*

[. . .] Only actual costs are relevant under the Commission's methodology, and the burden is on the applicant to demonstrate that the costs utilized in its application for market-based rate authority are actual costs, and not those set above the marginal cost of the marginal supplier, by any means."); see also *id.* at P 30 n.47 ("This includes not only supra-competitive rates supported by an alternative's market power, but other means of setting rates above costs, to include settlement and negotiated rates. . . .").

93. *Koch Gateway*, *supra* note 18, at 61,045.

94. *See, e.g.*, *id.* at PP 42, 18; *See also Mobil Pipeline Co.*, 676 F.3d 1098.

95. *Mobil Pipeline Co.*, 676 F.3d at 1103-04.

96. The manifestation of the Cellophane Fallacy in the *Mobil* proceeding was succinctly summarized by the presiding Administrative Law Judge in that case: "Suppose that a pipeline hypothetically *did* have market power. If I improperly assumed that the pipeline's market clearing rate was competitive and used that rate as the benchmark in the market power analysis, I would likely include alternatives to the pipeline in my market share calculation that were not in fact good competitive alternatives. The improper inclusion of alternatives would in turn reduce my calculation of the pipeline's relative market share and would possibly lead me, again, to improperly conclude that the pipeline *did not* have market power. This phenomenon is known as the 'Cellophane Trap.'" *Mobil Pipe Line Co.*, 128 F.E.R.C. ¶ 63,008, at P 77 (2009).

bil Court incorrectly implied that a competitive rate level was reflected in "Pegasus's full value to Western Canadian crude oil producers and shippers."[97] To the contrary, as the Supreme Court has correctly recognized, "focus on the willingness or ability of the purchaser to pay for a service is the concern of the monopolist, not of a governmental agency charged both with assuring the industry a fair return and with assuring the public reliable and efficient service, at a reasonable price."[98]

Notably, the *Mobil* decision did not address the fact that the "regulated" rate that was used as a baseline in the Commission's analysis of Pegasus was a "negotiated" rate voluntarily agreed to by Pegasus prior to undergoing its capital investment. In contrast to the Court's *Mobil* decision, the significance of Pegasus implementing a negotiated rate was thoroughly and correctly analyzed by the presiding Administrative Law Judge in the Pegasus proceeding, who stated:

> I believe that the assumption that the market clearing rate is necessarily competitive puts the cart before the (winged) horse. The purpose of this market power proceeding is to determine whether there exist sufficient competitive alternatives to constrain Pegasus' rates to just and reasonable levels. **Clearly, the market power analysis should not begin with that very potential outcome: the benchmark price should not be based on the as yet unproven assumption—indeed the presumption—that the rate Pegasus would be able to charge if granted market-based authority would necessarily result from a truly workably competitive market.** Here the Staff's [as also relied on by the D.C. Circuit in its *Mobil* decision] presumption assumes the conclusion of its analysis. . . .
>
> Further, Suncor/CNRL points out that because Pegasus' prevailing tariff rate was a negotiated tariff rate, which was filed with no cost justification provided, there is no evidence that any cost advantage is reflected in the prevailing rate. Further, Suncor/CNRL argues that the prevailing tariff rate must be greater than Pegasus' long-run average cost; otherwise Pegasus would not have voluntarily agreed to the long-term rate. . . .
>
> I find that Pegasus' prevailing tariff rate reasonably reflects the long-run competitive price for transportation services in Pegasus' origin market. . . . **I find that the evidence presented by Shippers demonstrate that Pegasus' prevailing tariff rate reasonably reflects—and perhaps somewhat overstates—Pegasus' long-run average costs.**[99]

Pegasus pipeline had implemented its new transportation service in April 2006, and at the time of its market-based rates application in August 2007, it remained the only supplier of crude oil transportation from Patoka, Illinois, to the

97. *Mobil Pipeline Co.*, 676 F.3d at 1103-04. Note that this statement by the Court is economically incorrect for the same reason that the Commission's statement in *Seaway I* that "a competitive price is by definition at the point where supply and demand intersect" is wrong. *Seaway I*, *supra* note 15, at P 49. It is true that any market price is determined by the intersection of supply and demand. But not all market prices reflect *competitive* price levels, for the simple reason that not all markets are competitive. If the supply and demand curves in question are determined by competitive forces, then the market price occurring where they intersect will be a competitive price. However, if supply in a market is influenced by the exercise of market power, then the market price will reflect that exercise of market power, and will *not* represent a competitive price.

98. Gainesville Util. Dept. v. Florida Power Corp., 402 U.S. 515, 528 (1971).

99. *Mobil Pipe Line Company*, 128 F.E.R.C. ¶ 63,008, at PP 69, 76, 87 (emphasis added) (note that Dr. Arthur provided testimony in this docket on behalf of Suncor Energy Marketing Inc. and Canadian Natural Resources Limited).

Gulf Coast, which in turn was the only route for Canadian heavy crude oil to reach the Gulf Coast.[100] As the ALJ noted, the fact that Pegasus had voluntarily accepted a negotiated rate means that its long run marginal costs and long-run average costs were below the $1.218/bbl negotiated rate level.[101] However, when Pegasus was granted market-based rates in 2012 following the *Mobil* decision, Pegasus increased its rates by approximately 300% to $5.0791/bbl.[102] According to the *Mobil* Court's erroneous reasoning, this much higher rate would be deemed "competitive" because it reflected the *value* of Pegasus's transportation to shippers, even though it clearly exceeded Pegasus's long-run marginal costs, which were below $1.218/bbl.

Further evidence that the Court erred in finding that Pegasus's regulated rate was below a competitive level was provided when another pipeline later began offering the same transportation service. In May 2017, the Energy Transfer Crude Oil Company, LLC pipeline voluntarily agreed to charge a negotiated uncommitted tariff rate of $1.85/bbl for a new crude oil transportation service from Patoka to Nederland, TX,[103] indicating that its long-run marginal cost of implementing the *same crude oil transportation service as Pegasus*—approximately ten years *after* Pegasus initiated service—was at or below that rate, which when deflated back to a 2008 level, is within 5% of Pegasus' negotiated rate of $1.218/bbl.[104]

To summarize: two pipelines implemented the same transportation service, both voluntarily agreeing to charge negotiated rates of approximately the same magnitude—and which necessarily must have been at least as high as each pipeline's respective long-run marginal cost of providing the same transportation service. This is strong direct evidence that a long-run competitive rate level for transportation from Patoka, Illinois, to the Gulf Coast is at or below the negotiated rate levels charged by Pegasus and Energy Transfer Crude Oil Company, LLC. Clearly, a conservatively *high* estimate of a competitive rate level is in the vicinity of Pegasus's $1.218/bbl negotiated rate at the time of its application, which was the competitive price proxy relied on by the ALJ.[105]

In contrast, the *Mobil* Court wrongly focused on the *value* to shippers of crude oil transportation from Patoka to the Gulf Coast as representing a competitive rate level, instead of considering the underlying long run marginal cost of that transportation service, and consequently reached the faulty conclusion that Pegasus's $1.218/bbl rate was *below* a competitive level. Pegasus's implementation of a $5.071/bbl rate after being granted market-based rates confirms the inaccuracy of the Commission's and Court's determination that the presence of multiple "used" alternatives for crude oil transportation from Western Canada was sufficient to

100. *Id*. at PP 2, 35. Pegasus's initial negotiated uncommitted rate was $1.10/bbl, which was indexed to $1.218/bbl at the time Pegasus filed its application for market-based rates in August 2007.

101. *Id*. at P 87. Otherwise Pegasus would not have expended capital to initiate the transportation service.

102. Mobil Pipe Line Company Local and Proportional Tariff, F.E.R.C. No. A-1210.3.0 (Oct. 1, 2012).

103. Energy Transfer Crude Oil Company, LLC Local Pipeline Tariff, F.E.R.C. No. 2.0.0 (May 14, 2017).

104. A $1.85/bbl rate in 2017, if deflated based on the 44.4% cumulative increase in FERC's oil pipeline index level between late 2007 and early 2017, would be worth $1.2815/bbl at the time of Pegasus's market based application in 2008, which is within 5% of the $1.218/bbl negotiated rate Pegasus had at that time.

105. *Mobil Pipe Line Co.*, 128 F.E.R.C. ¶ 63,008, at PP 69, 76, 87.

prevent the exercise of market power by Pegasus. The $5.071/bbl market-based rate charged by Pegasus clearly dramatically exceeded both Pegasus's and Energy Transfer Crude Oil Company, LLC's long-run marginal cost of providing the same crude oil transportation service. Given that competitive rates are defined by being reflective of the long-run marginal cost of the marginal supplier of the service in question, Pegasus's implementation of a rate more than *four times greater than marginal cost* represents direct evidence that Pegasus possessed—and exercised—market power.

b. Flawed Reasoning Regarding "Excess Demand"

Another flaw in the Commission's policy for identifying a competitive price proxy relates to its economically unsound interpretation of "excess demand" that may exist at a prevailing tariff rate. Both the Commission and the D.C. Circuit Court have also expressed concern that existing tariff rates may be far below a competitive rate due to the presence of "excess demand" at the existing tariff rates,[106] leading to a "reverse cellophane trap" where competitive alternatives are inappropriately excluded from the market share analysis, thereby biasing the analysis toward a finding of market power.[107] Specifically, referencing the *Mobil* Court's incorrect conclusion that Pegasus's negotiated rate was below a competitive rate, the Commission has incorrectly reasoned that "where a pipeline experiences excess demand at its current tariff rate, [. . . t]o reach the competitive price, the pipeline's rate would need to increase to a point that eliminated excess demand."[108]

However, contrary to the Commission's and Court's erroneous reasoning, fundamental economics clearly demonstrates that excess demand *does not* indicate whether prevailing price is above or below the competitive price level. In fact, excess demand may be present when a price is moving from below a competitive level toward a competitive level, but it is just as likely to be observed when a price is moving up from a competitive level toward a monopoly price level. If price is artificially held below a competitive price level, then excess demand at that price would be expected—since with a typical upward-sloping supply curve and downward sloping demand curve, there will be more demand than supply at any price below the market-clearing intersection of the curves. However, excess demand can also occur when price is increasing from a competitive level to a level reflecting the exercise of market power. Prices rise from competitive levels to monopoly levels as supply is restricted below competitive supply levels, creating excess demand at the competitive price level. Prices rise to equate demand with a lower monopoly supply, but the resulting price is a monopoly price, not a competitive price that reflects marginal cost. Thus, the presence of excess demand at any given

106. *Seaway II*, *supra* note 15, at P 33; *Mobil Pipeline Co.*, 676 F.3d at 1103.

107. *Seaway II*, *supra* note 15, at P 26.

108. *Id*. at P 39 (citing *Mobil Pipeline Co.*, 676 F.3d 1098). As discussed above, *Mobil* erroneously concluded that Pegasus's negotiated rate was below a competitive level because shippers valued the constrained transportation service above the negotiated tariff rate.

price level does not determine whether price is moving from below a competitive level up toward that competitive level, or moving above the competitive level toward a monopoly level.[109] Rather it is the relationship between price and marginal cost that determines whether a price is competitive or monopolistic.

c. Market Power vs. "Scarcity Rent"

With respect to the use of long-run marginal cost as a metric to evaluate the competitiveness of oil pipeline transportation rates, the Commission has argued that pipelines may not be able to expand and take business away from higher cost alternatives, meaning that rates may not be driven to any pipeline's long-run marginal cost level:

> [U]nlike some businesses, oil pipelines cannot easily expand capacity in order to take every customer away from higher-priced competitors. Not only can expansion be time consuming, and involve a plethora of legal, geographic, political, and engineering hurdles, expansion can involve costs far in excess of existing tariff rates or even competitor's rates.[110]

While the Commission appears to have intended these comments to suggest that even under competitive conditions market prices may not be driven to long-run marginal cost, its reasoning on this point is flawed. In fact, the circumstances that make entry and expansion difficult and slow in the oil pipeline industry are precisely the circumstances that confer natural monopoly characteristics to oil pipelines, which is the basis for the economic regulation of their rates to prevent the potential exercise of market power.[111] As such, the barriers to entry in the oil pipeline industry are actually one reason why long-run marginal *is* a relevant consideration when determining a reasonable proxy for a competitive rate.

The Commission has also held that rates in a competitive market for oil pipelines may not be driven to the lower costs of any given alternative and that "[w]here multiple entities are selling into a market, one must first identify the marginal supplier and then examine that entities costs when determining a competitive price proxy."[112] Here the Commission is raising the possibility that some pipelines may have costs below those costs of a marginal supplier of the same service, such that these "infra-marginal suppliers" would earn "scarcity rents," wherein higher returns are earned because of advantaged access to a scarce input rather than due to an exercise of market power.

As discussed above, extraordinary profits resulting from market power (known as "monopoly rents") are earned when price exceeds marginal cost. In contrast, "scarcity rents" are earned when a firm has access to a specific input that cannot be duplicated by other firms in the market.[113] Importantly, there is a test

109. Contrary to its more recent statements, the Commission has correctly understood these principles in the past. *See* Order No. 712-A, *supra* note 12, at PP 33–34.

110. *Seaway II*, *supra* note 15, at P 43.

111. OIL PIPELINE DEREGULATION – REPORT OF THE U.S. DEPARTMENT OF JUSTICE, ANTITRUST DIVISION (May 1986). *See also Farmers Union II*, 734 F.2d at 1509 n.51.

112. *Seaway II*, *supra* note 15, at P 41.

113. Areeda *et al.*, *supra* note 25, at ¶ 516c at 138–139.

for distinguishing between "monopoly rents" and "scarcity rents" – simply put, a firm charging prices in excess of its own marginal cost is exercising market power and not earning "scarcity rents." Areeda *et al*. explain the distinction as follows:

> Importantly, the firm earning scarcity rents rather than monopoly returns sets price at marginal cost, just as the competitor does. [. . . I]ts prices are above average total cost, thus giving it the high return, but not above marginal cost. The firm operates under the same constraint that generally faces the competitor: it can produce as little or as much as it pleases at the market price, but it has no power to raise the market price by reducing output. This fact is important because the elimination of high profits per se is not the goal of the antitrust laws, and, indeed, sometimes we say that marginal cost pricing *is* an important antitrust goal. By this measure, the firm earning scarcity rents is in full compliance.[114]

This suggests that comparing a pipeline's prevailing tariff rate to its long-run marginal cost is a straightforward method for discerning between scarcity rents and profits from the exercise of market power. As Areeda *et. al.* aptly summarize, "at least some power over price—and hence some monopoly profit—is indicated where price exceeds *marginal* cost for the firm in question; and substantial power is clear when the firm could expand its capacity and satisfy the entire market demand at costs well below the current price.[115] Thus, any uncertainty regarding whether a pipeline is earning a scarcity rent or exercising market power is testable, and there is no basis for *presuming* that prevailing rates in excess of average or marginal cost represent scarcity rents, as is done in the Commission's current policies. Indeed, given the economies of scale associated with a large pipeline system, it is at least as reasonable to begin with precisely the *opposite* presumption: that a large incumbent pipeline *would* be able to expand at a marginal cost level below the rates of higher cost alternatives, but the ability to maintain rates above its marginal cost incentivizes it to instead withhold expansion capacity in an exercise of market power.

B. Recommended Changes to FERC's Policy for Market-Based Rates

To remove the incentive for an incumbent pipeline to withhold transportation capacity prior to or after being granted market-based rates, we recommend that the Commission cease its policies of presuming that "used" alternatives are competitive, and that prevailing locational commodity price differentials represent a competitive rate level for oil and NGL pipeline transportation service. Instead, we recommend that the Commission adopt a policy that (i) a reasonable proxy for a competitive transportation rate should be based on an estimate of the long-run marginal cost of providing incremental transportation capacity, and (ii) competitive alternatives should be identified based on whether shippers *would* and *could* shift volumes to the alternatives in response to a rate increase by the subject pipeline above a competitive level.

We recommend that the Commission identify competitive alternatives to a subject pipeline to be included in market share and market concentration statistics

114. *Id.* (emphasis added).

115. *Id.*

in an origin (or destination) market according to: (1) whether the alternative provides a netback (or delivered) price greater than the netback (or delivered) price attainable on the subject pipeline at a long-run marginal cost-reflective competitive transportation rate level increased by a small but significant amount (competitive in terms of price); (2) whether the alternative could transport additional volumes shifted from the subject pipeline (competitive in terms of availability);[116] and (3) whether the alternative is of comparable quality to the subject pipeline.

1. Clarifying the Relevance of the Long-run Marginal Cost of Transportation in Determining a Proxy for a Competitive Rate

To understand the relevance of long-run marginal cost in the context of a large incumbent pipeline system offering a given transportation service (such as might be at issues in a FERC market-based rates proceeding), we think it is useful to contemplate and compare alternative ownership structures for such a system. One possible organizational structure for a pipeline system is an undivided joint interest (UJI), where there are multiple independent owners—each one having a separate management team, offering its own separate services, and charging its own tariff rates—but all using the same physical pipeline facilities. In such circumstances, the UJI owners pool their resources to make the large capital investments necessary to achieve economies of scale. However, each separate owner of the UJI pipeline system retains its individual right to undertake incremental expansions of the combined system at its own cost to capture incremental volumes.[117]

The UJI pipeline structure provides a useful analytical model to think about incentives to expand and compete in situations where the significant economies of scale inherent in a capital intensive pipeline system serve to deter new entrants that would have to replicate an incumbent's facilities to compete. Consider what would happen if the ten owners of a hypothetical UJI pipeline system had ten different managerial entities, each with its own distinct profit motive. Under these circumstances, the separate individual owners of the hypothetical UJI pipeline would have an incentive to compete with each other to capture incremental volumes associated with expansions of the overall pipeline system. In that case, each owner would be willing to undertake an expansion that provided expected incremental revenue that recovered its incremental cost of expansion, including a rea-

116. As discussed above, we recommend that alternatives operating at capacity—such that shippers could not shift volumes to those alternatives from the subject pipeline—be excluded from market power statistics when evaluating whether the subject pipeline possesses market power. *See supra* section III.A.1.b.

117. For example, Saddlehorn Pipeline Company, LLC (Saddlehorn) and Grand Mesa Pipeline, LLC (Grand Mesa) entered into a UJI pipeline arrangement to provide crude oil transportation service. Saddlehorn and Grand Mesa are independently owned and managed entities, and each has the right and ability to undertake expansions of the combined system at its own cost, and in doing so capture incremental volumes at its own tariff rates. *See, e.g.*, *Saddlehorn Pipeline Company, LLC*, 155 F.E.R.C. ¶ 61,225, at PP 1-8 (2016). In fact, Saddlehorn undertook an incremental expansion of the original combined system, whereby the incremental volumes move under Saddlehorn's tariff rates rather than Grand Mesa's tariff rates. *Saddlehorn Pipeline Company, LLC*, 129 F.E.R.C. ¶ 61,118, at PP 1-6 (2019).

sonable return on investment. In other words, each UJI owner would be incentivized to expand by the ability to charge a rate greater than or equal to its long-run marginal cost. It is precisely this dynamic of *multiple sellers competing with each other (which, as the UJI example illustrates, does not have to entail multiple systems) that produce a competitive outcome*, where price is driven to a competitive level equal to long run marginal cost.[118] The same principles apply when analyzing a market in which an incumbent pipeline is *not* a UJI, but rather has a traditional ownership structure with a unitary profit incentive. Though the competitive dynamics associated with UJI owners competing to expand capacity would not exist in this situation, it is still the case that the long-run marginal cost that would be incurred to expand capacity remains a relevant indicator of a competitive rate level for that transportation service.

In its *Seaway II* decision, despite inappropriately assuming that a pipeline without market-based rates would be unable to exercise market power,[119] the Commission correctly recognized that prevailing transportation rates, including those set by market-based rates, settlement, or negotiated rates, cannot be assumed to reflect competitive levels. Further, the Commission's discussion indicates that anyone performing an analysis of market competitiveness must demonstrate that the competitive price proxy is not above the marginal costs of the marginal supplier:

> [T]he Commission in the Order on Rehearing held that the competitive price is the marginal cost of the marginal supplier, not the prevailing price. [. . .] The Commission did not find that *any* market-clearing price was by definition a competitive price, or that prevailing prices are by definition just and reasonable rates. Only actual costs are relevant under the Commission's methodology, and the burden is on the applicant to demonstrate that the costs utilized in its application for market-based rate authority are actual costs, and not those set above the marginal cost of the marginal supplier, by any means. [*footnote*: This includes not only supra-competitive rates supported by an alternative's market power, but other means of setting rates above costs, to include settlement and negotiated rates . . .][120]

While the passage of *Seaway II* quoted above does not precisely explain what constitutes the "marginal supplier" for determining the competitive transportation price, the Commission has correctly defined this term in prior decisions. For example, the *Koch Gateway* decision addressing market power analysis makes clear that marginal supplier of *transportation* between given points that is the relevant marginal supplier.[121] As the Commission stated in *Koch Gateway*:

118. Order No. 572, *supra* note 13, at 31,180 (quoting *Tejas Power Corp.*, 908 F.2d at 1004).

119. *Seaway II*, *supra* note 15, at PP 26-29. Given that the majority of pipelines rates are not cost-based and a significant number are negotiated (*e.g.*, committed rates), it is inappropriate to presume that the rates are set by competitive forces. *See infra* section IV.

120. *Id.* at P 30 (one footnote omitted).

121. *Koch Gateway*, *supra* note 18, at 61,045.

> An appropriate base price in a market power evaluation of this type is the long-run competitive price. The long-run transportation price *between given points* in a competitive market will be determined by the long-run marginal cost for the marginal supplier of building and operating transportation facilities.[122]

According to these correctly-reasoned statements from *Koch Gateway* and *Seaway II*, identifying the relevant marginal cost of the marginal supplier requires examining suppliers of the *same or similar* transportation services to the one being provided by the subject pipeline.[123]

Consequently, we recommend that the Commission clarify that a competitive price proxy for the identification of transportation alternatives that are competitive in terms of price be determined based on an estimate of the long-run marginal cost of the marginal supplier the *same or similar transportation service* provided by the subject pipeline. Further, in contrast to the Commission's current flawed policy of presuming that "used" alternatives are competitive, we recommend that a cost-reflective price proxy be appropriately employed in a netback or delivered price analysis as part of a SSNIP test to provide an economically sound basis for identifying competitive alternatives in terms of price for inclusion in market concentration calculations.

2. Methodology for Reliably Estimating the Long-run Marginal Cost of Transportation

Where information exists regarding the costs incurred by current market participants to *expand* transportation service, these actual experienced costs can provide a reliable estimate of the long-run marginal cost to serve the marginal unit of demand for the transportation service in question. In this section, we discuss how established estimation techniques and readily-available relevant data can be employed to derive reliable estimates of long-run marginal cost to employ as a competitive rate proxy in a market power analysis.

There is a history of academic research concerned with methods for estimating long-run marginal costs in capital-intensive utility industries. For example,

122. *Id.* at 61,045 (emphasis added). Similarly, in *Seaway II*, the Commission presented a hypothetical with five pipelines providing the *same* transportation service, one of which was identified as the marginal provider of transportation *between the given points*, consistent with the Commission's prior statement in *Koch Gateway*. *Seaway II*, *supra* note 15, at Appendix PP 1–7. Note that Commission's example in the Appendix relies on an erroneous assumption that each pipeline's prevailing tariff rate equals its marginal cost, an assumption the Commission clearly states should not hold without examining the underlying marginal costs of each alternative. *Id.* at P 30. Further, note that the inclusion of alternatives operating at capacity in the *Seaway II* Appendix's example HHI calculations is clearly inconsistent with the Commission's prior correct recognition that alternatives that are operating at capacity are not good alternatives in terms of availability and should be excluded from HHI calculations. *Seaway I*, *supra* note 15, at P 45.

123. As discussed above in section III.A.2.a, it does not make economic sense to infer that the marginal costs of a *dissimilar* transportation services—including non-pipeline transportation alternatives—could represent the marginal cost of the marginal supplier in the transportation service being provided by the subject pipeline. Rather, only the marginal costs of suppliers of *like* transportation services are relevant when determining which supplier is the marginal supplier of that service.

Professor Ralph Turvey published a survey of applications of marginal cost concepts in the electric, water, railroad, and natural gas transmission industries.[124] Another article by Mann, Saunders, and Warford summarized common estimation methods and discusses their relative merits in the context of water infrastructure investment.[125] This literature establishes that when an industry (such as the oil pipeline industry) is characterized by "capital indivisibility"—featuring a "lumpy" pattern of periodic large investments in incremental expansion facilities—the "Average Incremental Cost" (AIC) method provides the most relevant estimate of long-run marginal cost.[126] Unlike other methods, AIC considers all incremental investment costs and associated incremental operating expenses used to meet all incremental demand over a specified time horizon.[127]

Calculating average incremental cost involves the following steps: (1) forecast incremental demand (*i.e.*, demanded transportation throughput in excess of current levels) over a specific time horizon; (2) forecast the incremental operating expenses and capital investments necessary to meet incremental demand over that time period; and (3) compute the discounted sum of all incremental costs and divide this by the discounted sum of all incremental throughput during the forecast horizon.[128]

While in some contexts data on incremental cost may not be available,[129] it is very often the case that internal analyses commonly performed by pipeline com-

124. Ralph Turvey, *What are Marginal Costs and How to Estimate Them?*, UNIV. OF BATH (2000).

125. Patrick C. Mann, Robert J. Saunders, & Jeremy J. Warford, *A Note on Capital Indivisibility and the Definition of Marginal Cost*, 16 WATER RESOURCES RESEARCH 602, 602-04 (1980).

126. *Id*.

127. This is important when estimating the long-run marginal cost for oil transportation by pipeline between an origin and a destination because pipeline transportation rates reflect the costs to meet demand for that transportation service over a projected future period. If all incremental demand over the forecast horizon can be met with a single capacity expansion, the capital costs for that expansion should be averaged over all the incremental demand in that period—not just the incremental demand in the year of the expansion. Further, the capital costs included in the AIC calculation should reflect only the portion of the expansion's useful life that is used to serve output during the forecast period. This can be handled either by annuitizing the capital expenditures to be incurred annually over the forecast period, or by treating the unamortized "terminal" value of each capacity addition capital investment as a "negative" cost in the final year of the specified forecast horizon. *See* Turvey, *supra* note 124, at 29-31.

128. We note that it is appropriate to use the firm's cost of capital to discount both the incremental costs as well as the incremental throughput when attempting to estimate the firm's marginal cost per unit.

129. In circumstances where no expansions of relevant transportation capacity have been performed or even considered over any extended period, then the data necessary to derive a reliable estimate of long-run marginal cost may not be available. However, a lack of consideration of projects to develop or expand capacity over a sustained period of time indicates that there is sufficient capacity associated with the subject pipeline's transportation service and its alternatives. In such circumstances, examining the subject pipeline's long-run average cost is a potential alternative to examining long-run marginal cost because at a long-run competitive equilibrium, long-run marginal cost equals long-run average cost. *See, e.g.*, CHARLES E. FERGUSON & J.P. GOULD, MICROECONOMIC THEORY at section 8.6c (5th ed.). Thus, even when transportation markets have not undergone recent expansions, fundamental economic principles strongly tilt in favor of estimating the competitive price based on the underlying costs of providing the transportation service, as opposed to by assuming prevailing prices

panies in the course of evaluating and executing expansion projects provide reliable and relevant data for estimating the long-run marginal costs to expand. Additionally, (and alternatively in instances where it is not possible to examine internal company analyses), FERC-regulated oil pipelines provide public cost and volume data in their annual and quarterly FERC Form No. 6 and Form No. 6-Q ("Form 6" and "Form 6-Q") filings, which data can be used to estimate the average incremental cost of expanded capacity.

We note that in a recent decision involving White Cliffs Pipeline's application for market-based rates, the Commission declined to rely on what it called "high-level estimates of marginal cost based on information from FERC Form No. 6 annual reports" and found that "data reported on FERC Form No. 6 annual reports can be difficult to rely upon for purposes of evaluating market power because of the aggregated nature of such data."[130] However, it is unclear why sworn quarterly and annual data that is provided by pipelines according to FERCs regulations cannot be relied on for purposes of estimating incremental capital and operating cost changes, especially since the Commission has relied on the very same data for the past twenty-five years to determine the level of its oil pipeline index.[131] Indeed, the primary reason that oil pipeline cost data reported in Form 6 remains "aggregated" in nature is that FERC has declined to require pipelines to provide more granular segmented data that regarding "costs that are more closely associated with [. . .] particular rate[s]."[132] We recommend requiring segmented Form 6 data to improve the transparency and usefulness of the reported cost data to evaluate the reasonableness of rates.

Further, even to the extent an estimate of long-run marginal cost must rely on data reported in FERC Form 6, any "aggregation" inherent in such data is likely to systematically *over*state the costs associated with specific incremental capacity, thus leading to a conservatively *high* estimate of the long-run marginal cost of providing transportation capacity between the relevant origin and destination markets. In contrast, FERC's current policy rejects any conservatively high imprecision that may result from aggregate reporting on FERC Form 6 in favor of a tautological presumption that prevailing tariff rates are free of the influence of market power.[133]

When a pipeline undertakes an expansion project, it is standard for the pipeline to perform economic analyses as part of the process of obtaining internal management approval for the capital expenditure. These internal project evaluations,

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or prevailing commodity price locational differentials reflect competitive levels as suggested by recent Commission precedent.

130. *White Cliffs Pipeline, L.L.C.,* Opinion No. 573, 173 F.E.R.C. ¶ 61,155, at P 51 (2020).

131. *See, e.g.,* Five-Year Review of the Oil Pipeline Index, 153 F.E.R.C. ¶ 61,312 (2015). *See also* Order No. 561, FERC STATS & REGS ¶ 30,985 (1993) and Order No. 561-A, FERC STATS & REGS ¶ 31,000.

132. *Withdrawal of Advanced Notice of Proposed Rulemaking and Order Denying Petition for Rulemaking*, 170 F.E.R.C. ¶ 61,134, at Glick (Commissioner) Dissent, P 2 (2020) (note that Dr. Arthur and Mr. Tolleth provided testimony in this docket on behalf of Airlines for American, the National Propane Gas Association, and Valero Marketing & Supply Company).

133. *See*, *e.g*., *White Cliffs Pipeline, L.L.C.,* Opinion No. 573, 173 F.E.R.C. ¶ 61,155, at P 49.

which are based on standard corporate finance analyses taught in undergraduate and graduate programs,[134] model the projected cash flows in order to estimate the net present value (NPV)[135] or the internal rate of return (IRR)[136] of the project. In evaluating which projects are economically beneficial to undertake, pipeline companies rely on data and projections of incremental capital costs, incremental expenses, and incremental volume to derive NPV and/or IRR estimates in support of their capital budgeting positions.[137]

An estimate of long-run marginal cost operates on the same principles and relies on the exact same inputs, except instead of relying on exogenous projections of the rates that a pipeline expects to charge, a long-run marginal cost analysis determines the rate level that makes the project break-even on a present value basis. In this context, the long-run marginal cost is equal to the rate level that would yield an NPV of $0 (and, equivalently, an IRR equal to the cost of capital) if it were levied on the incremental volumes over the applicable forecast horizon.[138] Consequently, calculating long-run marginal cost is not more complex and does not require more data than the standard internal analyses of NPV and IRR that are routinely conducted by firms across industries.

IV. FERC'S POLICY CONCERNING COMMITTED RATES INCENTIVIZES OIL AND NGL PIPELINES TO UNDER DEVELOP CAPACITY

Pipelines can enter into "committed" rate contracts with shippers whereby a shipper will commit to ship a certain volume at a specified tariff rate for durations of typically three to twenty years. The ability to enter into long-term contracts provides a clear incentive to expand capacity and provides benefits for both pipelines—which get greater certainty of cash flows for recovering invested capital—and shippers, who gain certainty of access to desired expansion capacity. However, FERC has stated that the revenue generated by negotiated committed shipper contracts can far exceed the pipeline's underlying costs, yet the Commission will not review the reasonableness of the negotiated committed rates.[139] In addition,

134. *See, e.g.*, RICHARD A. BREALEY, STEWART C. MYERS, AND FRANKLIN ALLEN, PRINCIPLES OF CORPORATE FINANCE 101-155 (10th ed. 2011).

135. NPV is a measure of the discounted incremental revenues less discounted incremental costs resulting from a project.

136. IRR is the achieved rate of return on investment computed on a levelized basis over the life of the project. In making capital budgeting decisions, a firm can compare a project's IRR to the cost of capital needed to finance the project. If the expected IRR exactly equals the cost of capital, the NPV of the project would be $0. If the expected IRR exceeds the cost of capital, the firm can expect to earn economic profits by undertaking the project (*i.e.*, the project has a positive NPV).

137. When performing internal financial analysis to evaluate an expansion project, the pipeline makes and multiplies projections of incremental volumes by the rates it expects to charge to develop incremental revenues; the pipeline then subtracts projected incremental capital and operating costs to calculate the incremental cash flows expected to be generated by the expansion project. These incremental cash flows are used to calculate the NPV and/or IRR metrics used to assess the economic benefits of the project.

138. Mann, Saunders, & Warford, *supra* note 125, at 602-604.

139. *Seaway Crude Pipeline Co.*, 146 F.E.R.C. ¶ 61,151, at PP 25-27 (2014).

within these committed contracts, pipelines often include a "duty to support" clause that requires the shipper not to challenge the reasonableness of the rate and to support the rates if challenged before FERC when the pipeline initially files those rates.[140] As discussed further below, these existing positions permit pipelines to implement committed rates in excess of the long-run marginal cost to expand capacity, and incentivize pipelines to expand capacity to levels less than would prevail under truly competitive circumstances. In our view, revising FERC's policies so as to apply comparable regulatory scrutiny to committed rates as well as other types of rates would maintain the beneficial aspects of committed shipper rates while (i) incentivizing greater development of capacity consistent with demand at competitive rate levels and (ii) protecting shippers against the exercise of market power by pipeline entities.

A. Overview of FERC's Existing Policy for Committed Shipper Rates

In first approving a proposed committed rate structure, the Commission reasonably noted "[t]he Commission finds that issuing a declaratory order is appropriate for a new oil pipeline entrant, such as Express, because it needs to acquire and guarantee financing in order to begin construction."[141] Over the last twenty years, the Commission has approved numerous other petitions for declaratory orders for committed rates for new and expansion capacity, and has clarified that committed rates will not be permitted without an expansion of capacity.[142]

The Commission also has approved committed and uncommitted rate structures based on "negotiated" committed and uncommitted rates where there was no cost data provided.[143] While uncommitted rates that are protested are required to be justified on a cost-of-service basis,[144] committed rates will only be reviewed by the Commission to determine whether the open season and contract formation process was "open, transparent, and free of the traditional contract nullifiers such as fraud."[145] The Commission will also assess whether committed rates are non-discriminatory.[146] However, the Commission has taken the position that it does not have to review the reasonableness of negotiated committed rate levels based on their relationship to underlying cost levels.[147]

140. *Colonial Pipeline Co.*, 146 F.E.R.C. ¶ 61,206, at P 32 (2014).

141. *Express Pipeline P'ship,* 75 F.E.R.C. ¶ 61,303 (1996); *order on reh'g*, 76 F.E.R.C. ¶ 61,245 (1996).

142. *Colonial Pipeline Co.*, 146 F.E.R.C. ¶ 61,206, at P 35.

143. *See e.g. Express Pipeline P'ship*, 76 F.E.R.C. ¶ 61,245 (1996); *Seaway Crude Pipeline Co.*, 142 F.E.R.C. ¶ 61,201 (2013).

144. *Seaway Crude Pipeline Co.*, 139 F.E.R.C. ¶ 61,109 (2012); *see also* Commission rule 342.2(a), 18 C.F.R. § 342.2(a), and Order No. 561, *Revisions to Oil Pipeline Regulations pursuant to Energy Policy Act of 1992*, [Regs. Preambles 1991-1996] F.E.R.C. STATS. & REGS. ¶ 30,985 (1993), *order on reh'g and clarification*, Order No. 561-A, [Regs. Preambles 1991-1996] F.E.R.C. STATS. & REGS. ¶ 31,000 (1994), *aff'd,* Ass'n of Oil Pipe Lines v. FERC, 83 F.3d 1424 (D.C. Cir. 1996).

145. *Seaway Crude Pipeline Co.*, 146 F.E.R.C. ¶ 61,151, at P 37.

146. *Express Pipeline P'ship*, 76 F.E.R.C. ¶ 61,245.

147. *Seaway Crude Pipeline Co.*, 146 F.E.R.C. ¶ 61,151, at PP 25-27.

The Commission "has always expressed concern that a pipeline with market power may establish an unjustly high rate through negotiation."[148] Indeed, as stated by one Commissioner, "[i]t would be illogical and inconsistent with the spirit of the Commission's oil pipeline rate regulation regime under the Interstate Commerce Act to require consumer protections to justify an initial rate, but to allow a carrier to exercise market power without check beyond the initial rate by entering into a long-term settlement rate devoid of consumer protections."[149] However, the Commission has nevertheless reasoned—wrongly in our opinion—that all market power concerns associated with negotiated committed rates "are remedied by providing a cost-of-service alternative [the uncommitted rate] to the negotiated [committed] rates."[150] In addition, while "duty to support" clauses—whereby a shipper entering into the contract is bound to support the rates and other terms of the contract as initially filed before FERC—appear to be routinely implemented in committed shipper contracts, the Commission stated that "it appears to be reasonable for contract shippers to support the specific rates to which they agreed."[151]

B. How FERC's Existing Policy Toward Committed Shipper Rates Incentivizes the Under Development of Capacity

As explained above, a pipeline with any market power has an incentive to exercise it by under-developing capacity so as to implement higher rates than would be supportable based on the cost to develop an economically efficient level of capacity.[152] This under development of capacity leads to the commodity price differential between an origin and a destination being higher than it otherwise would be, and permits pipelines with market power to charge committed rates higher than their long-run marginal cost. Because FERC has stated that it does not have to review the reasonableness of negotiated committed rates in relation to the underlying costs,[153] pipelines have the freedom to attempt to implement rates as high as possible, without ever having demonstrated to FERC that they do not have the ability to exercise market power.

In addition, "duty to support" clauses in committed shipper transportation service agreements attempt to foreclose the ability of the committed shippers from challenging the level of the committed rates upon their initial filing.[154] A "duty to

148. *Id.* at P 29; Order No. 561, F.E.R.C. STATS. & REGS. ¶ 30,985 at 30,959.

149. *ONEOK Elk Creek Pipeline, L.L.C.*, 167 F.E.R.C. ¶ 61,277, at P 6 (2019) (Glick, commissioner, concurring).

150. *Seaway Crude Pipeline Co.*, 146 F.E.R.C. ¶ 61,151, at PP 31-32.

151. *Colonial Pipeline Co.*, 146 F.E.R.C. ¶ 61,206, at P 32.

152. See the discussion in sections II and III above. *See also Guttman, supra* note 32, at P 299.

153. *Seaway Crude Pipeline Co.*, 146 F.E.R.C. ¶ 61,151, at PP 24-38 ("Once these rates are negotiated and accepted, any divergence between the rates and cost-of-service rates is not an issue of over-recovery . . . " "There is no question that the Commission allows for negotiated rates for committed shippers, and these rates will not be determined unjust and unreasonable solely due to a divergence from cost-of-service rates.").

154. *Colonial Pipeline Co.*, 146 F.E.R.C. ¶ 61,206, at P 32.

support" clause creates a situation where a shipper can be offered a rate that is higher than would prevail in competitive circumstances (higher than long-run marginal cost), yet the shipper is better off accepting the rate, gaining access to the capacity, and potentially foreclosing its ability to challenge the reasonableness of the rate—as compared to not having access to expanded transportation capacity in a market with higher commodity price differentials due to depressed origin prices or elevated destination prices.

With respect to FERC's assertion that requiring *uncommitted* rates to be set at a cost-based level in the event of protest remedies *all* market power concerns associated with negotiated committed rates,[155] having cost-based uncommitted rates is *not* equivalent to a "recourse rate" that can mitigate market power concerns in the context of the Commission's natural gas pipeline regulation. FERC permits natural gas pipelines to charge negotiated rates that can be greater than its cost-based rate, including negotiated rates based on fluctuating commodity price basis (locational) differentials, but also requires the natural gas pipeline to offer a cost-based rate, which it refers to as a "recourse" rate.[156] When entering into a contract or transportation service agreement with a natural gas pipeline, a shipper, while having the ability to *keep all the non-rate terms of the contract the same*, also has the *option* of selecting a cost-based recourse rate if the shipper does not find the negotiated rate being offered to it by the natural gas pipeline acceptable. Thus, if the natural gas pipeline shipper is contemplating entering a *firm* transportation contract, where the shipper assumes a take-or-pay obligation in exchange for its right to reserve capacity, the shipper has the *option* of paying a cost-based recourse rate instead of the negotiated rate offered by the natural gas pipeline, *while maintaining all the same priority access rights* to the capacity.[157] In contrast, shippers contemplating entering into committed contracts on oil pipelines do not have the *option* of a cost-based recourse rate instead of the "negotiated" committed rate

155. *Seaway Crude Pipeline Co.*, 146 F.E.R.C. ¶ 61,151, at PP 29-32; *White Cliffs Pipeline, L.L.C.*, 173 F.E.R.C. ¶ 61,155, at P 49 (2020) ("We find that it is reasonable to conclude that the negotiated rates in the market do not reflect an exercise of market power. The contract rates in the market were freely negotiated between the pipelines and the shippers using an open season process pursuant to the Commission's committed rate policy . . . because the contracts were freely negotiated, we find no reason to believe that any duty-to-support clauses in these freely negotiated contracts inhibits competition. The same reasoning also applies to rates set under section 342.2 of the Commission's regulations based upon the agreement of a non-affiliated shipper. Such rates are presumed competitive because they are freely negotiated between the pipelines and the shippers.") (footnotes omitted).

156. *See Natural Gas Pipeline Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy*, 104 F.E.R.C. ¶ 61,134 (2003), *order on reh'g and clarification*, 114 F.E.R.C. ¶ 61,042, *dismissing reh'g and denying clarification,* 114 F.E.R.C. ¶ 61,304 (2006). *See also Interstate and Intrastate Natural Gas Pipelines; Rate Changes Relating to Federal Income Tax Rate*, 162 F.E.R.C. ¶ 61,226, at P 14 (2018) ("In order to be granted negotiated rate authority, a pipeline must have a cost-based recourse rate on file with the Commission, so a customer always has the option of entering into a contract at the cost-based recourse rate rather than a negotiated rate if it chooses.")

157. *Natural Gas Pipeline Negotiated Rate Policies and Practices; Modification of Negotiated Rate Policy*, *dismissing reh'g and denying clarification,* 114 F.E.R.C. ¶ 61,304, at P 4 (2006) ("The availability of a recourse service would prevent pipelines from exercising market power by assuring that the customer can fall back to cost-based, traditional service if the pipeline unilaterally demands excessive prices or withholds service.").

level offered by the pipeline. Indeed, oil pipeline uncommitted rates differ from natural gas pipeline recourse rates in two main respects.

First, the non-rate terms of service for uncommitted service are not equivalent to the non-rate terms of service for committed rates. Consequently, a cost-based alternative rate cannot be a "recourse" rate if a shipper can only have the cost-based rate if other non-rate terms of service are different from those for the committed service. Of particular note, the priority given to committed shippers in the allocation of constrained capacity is commonly a significantly higher quality than the priority given to uncommitted shippers. For example, Seaway Pipeline entered into committed shipper contracts prior to commencing its new crude oil transportation service.[158] However, when Seaway implemented the rules and regulations associated with its new crude oil transportation service, committed shippers were defined as "regular shippers" that would be allocated 90% of available capacity to at least the volume level associated with their contract volume level, while uncommitted shippers were defined as "new shippers" that collectively would be allocated 10% of available capacity.[159] Consequently, the terms of service associated with priority for pro-rationing on Seaway were clearly different for committed and uncommitted shippers, as illustrated by uncommitted "new" shippers on Seaway making nominations for 2.1 *billion* barrels for transportation in April 2013 associated with just 900,000 barrels of capacity set aside for the uncommitted shippers.[160] The uncommitted shippers on Seaway were attempting to build shipper history in the presence of significant pro-rationing of their nominations while committed shippers were being allocated capacity at their committed volume level. In these circumstances, uncommitted shippers are clearly receiving a different class of service, and paying a cost-based uncommitted rate does nothing to improve the uncommitted shippers' terms of service to the point of being similarly situated with committed shippers. Consequently, a cost-based uncommitted rate cannot be considered a "recourse rate" capable of mitigating market power concerns with respect to the committed shipper rate offered by a pipeline.

Second, a shipper does not have an *option* to enter into a cost-based committed rate instead of the "negotiated" committed rate offered by an oil or liquids pipeline. For example, when Seaway was offering committed rates and associated terms of service in an open season, a prospective shipper "sent a letter and a marked-up version of the proposed Transportation Services Agreement (TSA) to Seaway proposing changes in the rates and other terms and conditions contained in the TSA."[161] The prospective shipper states that it "received no response from

158. *See* Petition for Declaratory Order of Seaway Crude Pipeline Company LLC, FERC Docket No. OR12-10-000, at 4-6 (Dec. 10, 2012).

159. *See* Seaway Crude Pipeline Company LLC, Tariff FERC No. 2.0.0, item 17, filed April 13, 2012, effective May 12, 2012. Uncommitted shippers could not be eligible to be considered "regular shippers" until they had developed 12-months of history shipping on the pipeline. *Id.*

160. *Seaway Crude Pipeline Co.*, 143 F.E.R.C. ¶ 61,036, at P 13 (2013). Note that nominations represented approximately 237,000% of the capacity made available to the uncommitted shippers.

161. *Id.*

Seaway to its letter and proposed modifications to the TSA."[162] In this circumstance, the committed rates offered during an open season do not appear to be "negotiated" rates, and there is not the option of having a cost-based committed recourse rate. A shipper in these circumstances is in a take it or leave it situation, where the prospect of paying rates above a competitive level can be, and often, is, still preferable to foregoing access to transportation capacity and receiving a suppressed commodity price at a constrained origin (or paying an inflated commodity price at a constrained destination). By permitting oil and liquids pipelines to specify the committed rate level for their proposed service, with required "duty to support" clauses that potentially forecloses a committed shipper's ability to take any action other than supporting the committed rate level[163] and the absence of review by the Commission, pipelines have the incentive to exercise whatever market power they possess, resulting in higher rate levels and less expansion capacity than would prevail in competitive circumstances.

C. Recommended Changes to FERC's Policy Toward Committed Rates

In order to provide a balance that incentivizes oil and liquids pipelines to construct capacity consistent with competitive levels and provides the opportunity to earn a reasonable return on investment, while ensuring that rates are within a zone of reasonableness and not excessive, we recommend that FERC's existing policy toward committed rates be revised to (1) permit challenges to the just and reasonableness of committed rates based on the relationship of the rates to underlying costs (recognizing that oil and NGL pipeline uncommitted rates are not equivalent to natural gas pipeline cost-based recourse rates in their ability to mitigate market power concerns), and (2) clarifying that any "duty to support" clauses in transportation services agreements for committed shipper rates do not foreclose a shipper's ability to challenge the reasonableness of rates, including potentially during an open season process prior to entering into a committed shipper contract or after the committed rates are implemented. We also recommend that pipelines file Form 6 data that is segmented by each system associated with a separate rate base that would be used for establishing rates (including committed rates), thus providing sufficient cost and volume information to make a determination whether a particular rate is reasonable.

While the Commission states that a case-by-case inquiry into the extent of market power reflected in committed shipper rates would be "serving the questionable interest of protecting a buyer who voluntarily entered into an agreement with a dominant seller,"[164] under the Commission's current policy, potential committed shippers currently have no protection from an exercise of market power and

162. *See* the *Answer of Suncor Energy Marketing Inc. and Canadian Natural Resources Limited to Motions for Expedited Consideration, for Leave to Intervene Out-of-Time, for Leave to File Briefs on Exceptions, and for Leave to File Amicus Curiae Briefs*, FERC Docket No. IS12-226-000 at 1-2 (Oct. 30, 2013).

163. *Colonial Pipeline Co.*, 146 F.E.R.C. ¶ 61,206, at P 32 (". . . it appears reasonable for contract shippers to support the specific rates to which they agreed.").

164. *Seaway Crude Pipeline Co.*, 146 F.E.R.C. ¶ 61,151, at P 32.

an under-development of capacity is incentivized. Pipelines offering transportation services agreements with "duty to support" clauses, as well as the Commission's position that it will not review the reasonableness of committed shipper rates, limits the ability of a potential committed shipper from negotiating with a pipeline regarding committed shipper rates in the absence of several competing expansion proposals from other alternatives.

While the Commission is concerned that "[a] case by case inquiry into the presence and extent of market power in negotiated contracts would inject a new and potentially burdensome element into the analysis,"[165] an analysis of market power is not required. Rather, permitting committed shippers to seek an examination before the Commission into whether committed rates reflect reasonable levels would suffice to level the negotiations between potential shippers and a pipeline with market power. This is precisely the mechanism that leads to negotiated/settlement rates in protested rate filings or complaint proceedings that are filed with the Commission.

The potential for Commission oversight would facilitate the sharing of information during negotiations over a committed rate level, and increases the likelihood of negotiated rates being in a zone of reasonableness, where rates are neither "less than compensatory" nor "excessive."[166] Pipelines would not be expected to go forward with an expansion if the rates were expected to be less than compensatory, and the potential for regulatory oversight would facilitate sharing of information regarding the expected cost of the expansion project. Significantly, with the ability to exercise market power reduced, pipelines would also be incentivized to construct a level of capacity where the willingness to pay by shippers equals the long-run marginal cost of the expansion capacity, consistent with the outcome that would be expected to occur in a workably competitive market.[167] While the possibility of a request for Commission oversight can increase the burden on the Commission, this would be limited by shippers' incentive to avoid unnecessary litigation before the Commission. Because they bear 100% of their expenses associated with the litigation, shippers do not have an incentive to attempt to effectuate relatively minor changes in rates, and are only likely to seek redress from the Commission when committed rates being offered by a pipeline are far in excess of competitive levels.

165. *Id*.

166. *Farmers Union II*, 734 F.2d at 1501-02.

167. In a negotiation regarding expansion capacity, there are currently constraints in the existing transportation capacity and potential shippers have a demand for expansion capacity. In these circumstances, potential shippers desire expansion capacity, and while they would certainly prefer a lower rate, also recognize that the project will not go forward if the rates are less than compensatory. Further, expansion projects are likely to have uncertainties regarding the level of cost associated with the expansion. In situations of significant uncertainty, the sharing of expected costs can also facilitate negotiated outcomes whereby shippers are willing to bear a portion of the risk associated with cost uncertainties. For example, there have been executed committed shipper contracts whereby the implemented committed rates can vary based on the difference between the actual capital costs and the pre-construction estimate. *TransCanada Keystone Pipeline, LP*, 125 F.E.R.C. ¶ 61,025, at P 20 (2008).

V. CONCLUSIONS

FERC's recent pronouncements regarding its policies for approving committed shipper rates and evaluating market power associated with market-based rates applications create a regulatory environment where pipelines are incentivized to under-develop capacity and create capacity constraints from which they can profit by exercising market power. In order to provide a balance that (1) incentivizes oil and liquids to construct capacity levels consistent with competitive levels, (2) provide the opportunity to earn a reasonable return on investment in expansion capacity, and (3) ensures that rates that are within a zone of reasonableness and not excessive, we recommend certain specific changes to FERC's existing policies. With respect to the Commission's policies for evaluating oil pipeline market-based rates, we recommend that the Commission not presume that "used" alternatives are competitive, nor presume that higher cost alternatives, including non-pipeline alternatives, or prevailing locational commodity price differentials represent a competitive rate level for oil and liquids pipeline transportation service. Instead, we recommend that the Commission adhere to the fundamental principles of competitive economics by affirmatively clarifying that a reasonable proxy for a competitive rate should be based on an estimate of the long-run marginal cost of providing incremental transportation capacity, or tied to the underlying costs of providing the transportation service at issue. When it comes to the approval of committed shipper rates, in our opinion the Commission should recognize that uncommitted rates are not a recourse rate that mitigates any potential for the exercise of market power. Consequently, we recommend that the Commission articulate a clear policy that challenges to the reasonableness of negotiated committed rates in relation to underlying costs by committed shippers will be permitted, even in the presence of any "duty to support" clauses in transportation services agreements for initial committed shipper rates.

ALTERNATIVE MEASURES OF "REPRESENTATIVE MARKET PRICES" FOR FERC DELIVERED PRICE TESTS

John R. Morris,[*] Jéssica Dutra,[†] Tristan Snow Cobb[‡§]

Synopsis: The U.S. Federal Energy Regulatory Commission screens merger and acquisition applications by jurisdictional electric utilities, requiring applicants to calculate market shares and concentration. The shares and concentration are based on "Available Economic Capacity," (AEC) which is the generation capacity economically deliverable at a "representative market price" after excluding obligations to serve retail and wholesale customers under long-term contracts. Even small differences in price can significantly impact AEC. Traditionally applicants have used average prices based on historical data. Real-world price distributions are often skewed by outliers making average prices unrepresentative of typical market conditions. This article demonstrates that merger applicants inherently must either select prices and adjust generation levels or select generation levels and adjust prices to be consistent with those levels. It demonstrates that selecting prices consistent with other Delivered Price Test (DPT) data are more appropriate measures of representative market prices because they better replicate generation quantities and the incentive to exercise market power and, therefore, are more likely to separate anticompetitive mergers from those that are competitively benign.

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I. INTRODUCTION

The U.S. Federal Energy Regulatory Commission (FERC) reviews changes in ownership of jurisdictional electric utility assets in the United States.[1] Under section 203 of the Federal Power Act, FERC must find that a transaction is in the public interest in order to approve a merger or acquisition.[2] As part of its public interest review, FERC assesses transactions' effects on competition.[3] FERC uses a standardized five-step screening methodology to assess possible competitive effects. The steps are (1) to define relevant markets; (2) to identify potential suppliers to the market; (3) to calculate the size of those suppliers given generation capabilities and transmission limits, generation costs and market prices; (4) to calculate market shares and concentration; and (5) to make inferences about possible competitive effects from the shares and concentration.[4] For concentration screening thresholds, FERC uses the Herfindahl-Hirschman Index (HHI) measure of market concentration.[5] The HHI is the sum of the square of the market shares.[6] So, for example, the HHI for a market with four sellers having shares of 40, 30, 20, and 10% would have an HHI of 3,000.[7] FERC uses the HHI standards first

1. *See generally* Mark F Sundback, et al., *Electricity regulation in the United States: overview*, THOMSON REUTERS (July 1, 2020).

2. Federal Power Act, § 203(a)(4), 16 U.S.C. § 824b(a)(4) (2019) (" . . . the Commission shall approve the proposed disposition, consolidation, acquisition, or change in control, if it finds that the proposed transaction will be consistent with the public interest . . . ").

3. Order No. 642, *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, F.E.R.C. Stats. & Regs. ¶ 31,111, 65 Fed. Reg. 70,983 (2000) [hereinafter Order No. 642]. FERC also considers effects on rates and regulation. After repeal of the Public Utilities Holding Company Act, it also reviews effects on cross subsidization. *See* Federal Power Act § 203(a)(4), 16 U.S.C. § 824b(a)(4) (" . . . the Commission shall approve the proposed disposition, consolidation, acquisition, or change in control, if it finds that the proposed transaction . . . will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest.").

4. Order No. 592, *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, F.E.R.C. STATS. & REGS. ¶ 31,044, 61 Fed. Reg. 68,595 (1996), at p. 30,130 [hereinafter Order No. 592]; Order No. 642, *supra* note 3, at 31,882. If applicants fail the screens, they may cite to other factors indicating that the transaction is unlikely to be anticompetitive despite the screen failures. Order No. 642, *supra* note 3, at 31,879. For example, in *FirstEnergy* FERC found that three (of ten) screen failures were not a competitive concern "because they do not involve systematic failures in a highly concentrated market." *FirstEnergy Corp.*, 113 F.E.R.C. ¶ 61,222, at P 49 (2010).

5. *See* Orris C. Herfindahl, *Concentration in the U.S. Steel Industry*, unpublished dissertation, Columbia Univ., 1950; Albert O. Hirschman, *National Power and the Structure of Foreign Trade*, Berkeley, 1945. *See also* Albert O. Hirschman, *The Paternity of an Index*, 54 AM. ECON. REV. 761 (1964).

6. *Id.*

7. 402 + 302 + 202 + 102 = 1,600 + 900 + 400 + 100 = 3,000.

adopted by the U.S. Department of Justice in 1982.[8] When the post-transaction HHI is below 1,000, or below 1,800 and the HHI increase is less than 100, or the increase is less than fifty at any HHI level, the transaction passes the screens and no further analysis is needed.[9] When calculating the size of suppliers for the HHI, FERC requires two separate measures: Economic Capacity (EC) and Available Economic Capacity (AEC).[10] EC is the generation capacity that could economically be delivered at a "representative market price."[11] AEC is EC minus obligations to serve retail customers and wholesale customers under long-term contracts.[12] Because both EC and AEC are determined, in part, by the representative market price, the selection of the market price is an important determinant of the results of FERC's screening methodology.

Per FERC's screening methodology, applicants seeking to merge or acquire jurisdictional electric utility assets must provide representative market prices for representative periods in each destination market.[13] The screening methodology, also known as a Delivered Price Test (DPT), must be done for specific destination markets delineated by FERC.[14] Because supply and demand conditions vary significantly during a year, FERC mandates that the market concentration statistics must be calculated for specific periods.[15] Given the lack of long-term energy storage and the fact that interconnected transmission networks must balance supply and demand every second, some have claimed that every hour might be considered a relevant electric power market.[16] Rather than defining every hour as a market,

8. U.S. DEP'T OF JUSTICE, MERGER GUIDELINES (1982), at § III.A.1, https://www.justice.gov/archives/atr/1982-merger-guidelines.

9. Order No. 592, *supra* note 4, at 30,134 ("If the Guidelines' thresholds are not exceeded, no further analysis need be provided in the application.").

10. *Id*.

11. Order No. 642, *supra* note 3, at 31,886, 31,891 (" . . . [T]he NOPR proposed that a supplier's ability to economically serve a destination market be measured by generating capacity controlled by the supplier rather than historical sales data. We also discussed in the NOPR two generating capacity measures we believed appropriate for the competitive analysis screen: economic capacity (EC) and available economic capacity (AEC). . . . The Commission also believes that selecting representative market prices in a sensible manner is among the most critical components of merger analysis when determining players in the relevant market.")

12. *See* 18 C.F.R. § 33.3 (2019).

13. *Id.*

14. Order No. 697, *Market-Based Rates For Wholesale Sales Of Electric Energy, Capacity And Ancillary Services By Public Utilities*, F.E.R.C. STATS. & REGS. ¶ 31,252, 72 Fed. Reg. 39,304 (2007) [hereinafter Order No. 697] at P 231 (" . . . [T]he Commission will continue to use a seller's balancing authority area or the RTO/ISO market, as applicable, as the default relevant geographic market. However, where the Commission has made a specific finding that there is a submarket within an RTO/ISO, that submarket becomes the default relevant geographic market for sellers located within the submarket . . . ").

15. *Id*.

16. U.S. Department of Justice and Federal Trade Commission, Comments, FERC Docket No. RM16-021000, Nov. 28, 2016, Accession No. 20161128-5185, at 13 ("particular geographic markets may exist for less than a full year or even less than a full day, depending on variations in demand conditions."); Gregory J. Werden, *Identifying Market Power in Electric Generation*, PUB. UTIL. FORTNIGHTLY, at 18 (Feb. 15, 1996) ("Since electricity is not stored to any great extent, it is theoretically appropriate to delineate at least 8,760 separate hourly markets for short-term power within a year.")

the typical practice is to select ten representative periods covering a range of supply and demand conditions.[17] For the analysis to be meaningful, it is necessary to have representative demand levels, representative supply conditions, and a representative price level for each period.[18]

Delivered price test HHI results for AEC are typically much more sensitive to the representative market price than results for EC. As an example, we compared HHI levels for EC and AEC using two different price levels for PJM East of AP South market.[19] For EC, the average difference in HHI levels across ten DPT periods using the two prices was thirty, with a maximum difference of eighty-five. In contrast, the difference in HHI levels with the two price levels averaged 137 for AEC with a maximum of 453. Therefore, different representative prices have the potential to radically change market shares and the perceived competitive effects of a transaction. Recognizing the high sensitivity of HHI levels to prices, especially for AEC, FERC requires applicants to calculate HHIs using prices above and below the representative market prices.[20] This article explores different methodologies for selecting representative market prices and consequent inferences one may make about market power given the results of each methodology.

The merger filing requirements allow merger applicants to select the representative market prices used in their DPT.[21] This article demonstrates that the DPT methodology forces applicants to make a fundamental choice: either select price levels and adjust generation consistent with those prices or select generation levels and adjust prices to be consistent with those generation levels. It then evaluates four methodologies for estimating representative market prices. In order of our preference, they are (1) Implied Prices from historical generation levels and the DPT supply curves; (2) Modeled Prices calculated from a simple dispatch model given DPT data; (3) Median Prices during DPT periods based on historical data; and (4) Average Prices based on historical data. The first two methodologies are consistent with selecting generation levels and then adjusting prices, and the last two are consistent with selecting prices and then adjusting generation. Some form

17. *AEP Power Marketing, Inc.*, 107 F.E.R.C. ¶ 61,018, Appendix F (2004) (" . . . choose the season/load levels to analyze: Super-Peak, Peak, and Off-Peak, for winter, shoulder and summer periods, and an extreme Summer Peak, for a total of ten season/load levels . . . ").

18. Order No. 642, *supra* note 3, at 31,891 ("The Commission also believes that selecting representative market prices in a sensible manner is among the most critical components of merger analysis when determining players in the relevant market."); *see also id*. at 31,888-889 (" . . . as electricity markets change, the meaning of native load may change too, such that it is reasonable to consider it as part of a broader set of contractual commitments. We agree with commenters regarding the need to recognize the implications of retail access for evaluating AEC and EC results . . . As a result of these concerns, we encourage merger applicants who rely on estimates of retail access to provide sensitivity tests of their results showing how varying degrees of retail competition would affect.")

19. We compared HHI levels at the median price level based on historical prices and the median prices plus 10%.

20. 18 C.F.R. § 33.3(d)(6).

21. Order No. 642, *supra* note 3, at 31,890 ("We did not require a specific method for estimating market prices. However, we stated that the results must be supported and consistent with what one would expect in a competitive market. For example, we would expect prices to vary little from customer to customer in the same region during similar demand conditions (if there are no transmission constraints), but we would expect prices to vary between peak and off-peak periods.").

of the Average Price methodology, our least preferred, has been used by virtually all merger applicants in the past 20 years.[22] As demonstrated in section IV, historical market prices often present a skewed distribution in which the arithmetic average (mean) price is often substantially different from the median price level. Hence, we find that median prices often are more appropriate than averages in DPT analyses. More importantly, we find the most appropriate representative market prices are those consistent with other DPT data such as the load (demand) and generation costs.[23] Only prices consistent with generation levels support inferences about market power consistent with economic reality because any other measure will either understate or overstate the incentive and ability to exercise market power. This is because the incentive to exercise market power is related to the open generation position of sellers that would receive the benefit from withholding output and raising market prices.

This last point makes intuitive sense to economists and others studying market behavior. Price is a market clearing mechanism which reconciles supply and demand.[24] In other words, price is an endogenous result of underlying data on supply and demand conditions, not an exogenous factor that determines either supply or demand.[25] Because the objective for FERC is to evaluate the potential anticompetitive effects of mergers and acquisitions, a representative price is a price that is consistent with the supply and load data used to evaluate the transaction. Any other price provides a mismatch of data that is inconsistent with a market outcome. This is explained in more detail in section III, below. This concept is consistent with Order No. 592 where FERC used "competitive market price" instead of representative market price.[26] It is well known that in perfectly competitive markets, price equals marginal cost.[27] Therefore, the price found at the point where demand intersects the marginal cost supply curve in the DPT data is consistent with both economic and legal principles.

The remainder of the article is organized as follows: section II gives a history of how market prices have been calculated since the DPT methodology was adopted by FERC. It shows that the methodology has not remained constant but rather changed over time as FERC and practitioners have considered different factors relevant to the DPT methodology. Section III then discuss the difficulties of reconciling different pieces of historical data, such as demand levels, evidence of supply conditions, and historical market prices. When conducting DPT analyses

22. A recent exception is the NRG/Direct merger filing in 2020, which uses median prices instead of average prices. *See* Report and Affidavit of Dr. John R. Morris, NRG Energy Inc., *et al.*, FERC Docket No. EC20-96-000, (Aug. 31, 2020), Accession No. 20200831-5492. FERC approved the transaction. *See alos NRG Energy, Inc.,* 173 F.E.R.C. ¶ 62,103 (2020).

23. The quantity demanded is known as load in the electric power industry. This follows for the engineering concept that the amount of electric energy consumed places a load or resistance to the generators creating that energy. We will use the word load for demand throughout this article.

24. WALTER NICHOLSON & CHRISTOPHER M. SNYDER, INTERMEDIATE MICROECONOMICS AND ITS APPLICATION 406 (12th ed. 2017).

25. A notable exception is when price floors or price caps constrain prices from balancing supply and demand. But that is in the case in DPT analysis. If it were the case, one would simply use the price floor or cap.

26. Order No. 592, *supra* note 4, at p. 30,131.

27. *See, e.g.*, RICHARD LIPSEY & PETER STEINER, ECONOMICS 276 (4th ed. 1975) ("[Conditions of competitive equilibrium include] . . . [e]very firm produces where price equal marginal cost.").

applicants must either adjust prices to be consistent with underlying supply data or adjust generation levels to match historical measures of prices. Adjusting price levels rather than generation levels yields more accurate measures of market power because the incentive to exercise market power is proportional to the open generation (or energy) position of sellers. The traditional practice of adjusting generation levels to match some price level systematically leads to incorrect generation levels and inferences of market power. The section also shows that depending on the circumstances, higher market prices can have ambiguous effects on the HHI by either increasing or decreasing the measure of market concentration. Section IV then discusses the asymmetric nature of historical electricity prices and how that skewness drives average prices above median price levels. Section V evaluates the four methodologies for selecting representative market prices and demonstrates that methodologies consistent with other DPT data (implied prices and model prices) are more likely to produce economically meaningful results than are market prices based on historical price levels. Of the two historical price methodologies (median and average), median price levels are more likely to produce implied capacity factors closer to reality than are average prices. Section VI then discusses other factors relevant to selecting representative market prices. These factors include reliable methodologies in traditional markets where price data are scarce, considerations for the applicants' generation levels, load data, and considerations of the form or inclusion of intermittent generation and fuel costs. The common theme is that representative market price selection matters, and they should be determined with careful consideration of the other DPT data and structure. Finally, we present concluding thoughts in section VII.

II. History of Representative Market Prices

The DPT methodology for screening mergers was adopted by FERC on December 30, 1996, and the first merger applications using the methodology were filed in 1997.[28] Back then, most investor-owned utilities regulated by FERC were vertically integrated in traditional markets. That is, most FERC-regulated utilities owned generation, transmission, and distribution assets, and they generated most of the energy they delivered to their retail and long-term wholesale customers. As a result, relatively few short-term transactions existed with which to measure market price. Additionally FERC did not require filing of transaction data in a common format until 2002.[29] In the first application under the new rules in 1997, FERC staff estimated market prices by using system lambda data—a measure of the marginal generation cost of a utility.[30] Lambda data are reported by hour, so they can be matched to DPT periods based on system conditions (on-peak and off-peak) and load levels.[31] As FERC stated, in competitive markets, competition is

28. *See generally* Order No. 592, *supra* note 4.

29. Order No. 2001, *Revised Public Utility Filing Requirements*, F.E.R.C. STATS. & REGS. ¶ 31,127, 67 Fed. Reg. 31,043 (2002).

30. *Ohio Edison Co.*, 80 F.E.R.C. ¶ 61,039, at p. 61,105 (1997). System lambda data is a measure of the marginal cost of generation of the reporting utility.

31. The filing requirements specifies that the periods must be specified based on load levels. 18 C.F.R. § 33.3(c)(4) ("Because demand and supply conditions for a product can vary substantially over the year, periods corresponding to those distinct conditions must be identified by load level and analyzed as separate products.").

expected to drive prices down the marginal costs, so lambda data can be a valid proxy for market prices.[32] Several months later, Dr. Mark Frankena used average hourly system lambda data from 1996 for market prices in his DPT analysis for the Louisiana Gas and Electric Company/Kentucky Utilities Company (LG&E/KU) merger.[33] Thereafter, using average hourly system lambda data became common when conducting DPT analyses.

The use of system lambda data, however, was not universal. Regional Transmission Organizations (RTOs) with centralized dispatch were being formed at the same time. In those systems, generation owners received a market clearing price for the energy they generate, and load-serving entities paid that price for the energy they re-delivered to end uses. These were actual market prices, and applicants used the RTO prices for transactions within RTOs.[34] But the practice of using average prices during a DPT period remained.[35]

The use of lambda data was rejected by FERC in the Duke/Progress merger in 2011, when FERC required the use of market price data when available.[36] The justification was that system lambda data understated market prices, and artificially decreased the amount of AEC for applicants.[37] Instead of using system lambda data, FERC relied on prices from transactions reported in Electric Quarterly Reports (EQR).[38] Transactions reported in EQR data, however, may not be available for some, or even most, of a DPT period at some locations. Despite this, applicants have used averages of EQR prices to estimate market prices for DPT periods outside of RTOs.[39] With these EQR data, there is also a question as to how to best calculate representative market prices, as even "average" prices over DPT periods can be calculated or weighted in multiple ways. When calculating average prices for a section 206 review of market-based rates, FERC calculated volume-

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But the historical practice has been to first split hours based on seasons and then on North American Electric Reliability Corporation (NERC) definitions of on-peak and off-peak hours, and then split the on-peak hours based on load levels. In *Bayou Cove*, FERC Staff challenged the traditional method and the applicants defended the historical practice. Supplemental Affidavit of Julie R. Solomon, FERC Docket No. EC18-63-000, June 15, 2018, at 9-11. Although FERC did not rule on the issue in *Bayou Cove*, it did accept the analyses submitted in NRG Wholesale Generation that were based on the traditional periods. *See* Report and Affidavit of Dr. John R. Morris, FERC Docket No. EC19-63-000, (Mar. 1, 2019), Attachment JM-9, at 1-2 [hereinafter Morris (2019)]; *NRG Wholesale Generation*, 168 F.E.R.C. ¶ 61,166 (2019).

32. 80 F.E.R.C. ¶ 61,039, at 61,106.

33. Mark Frankena, Louisville Gas and Electric Company *et al.*, FERC Docket No. EC98-2-000, at 60 (Oct. 15, 1997) [hereinafter Frankena (1997)], which involved the merger of these companies. *See Louisville Gas and Electric Co.*, 82 F.E.R.C. ¶ 61,308 (1998).

34. *See, e.g.*, Workpapers of Dr. Joe Pace, Potomac Electric Power Company & Conectiv, FERC Docket No. EC01-101-000, May 1, 2001, Accession No. 20010516-0414; *Orion Power Holdings, Inc., et al.*, 98 F.E.R.C. ¶ 61,136, 61,396 (2002).

35. *Id.*, Report & Affidavit of Dr. John R. Morris, U.S. Gen New England, Inc., FERC Docket No. EC054-000, Attachment 3, at 17 (Oct. 8, 2004) [hereinafter Morris (2004)].

36. *Duke Energy Corp.*, 136 F.E.R.C. ¶ 61,245 (2011).

37. *Id.* at PP 119-129.

38. *Id.* at P 124.

39. *See, e.g.*, Duke Energy Corporation, Answer to Request for Additional Information, FERC Docket No. EC11-60-000, at 5 (Aug. 29, 2011).

weighted average prices by hour.[40] This provides some guidance on how to establish a "price" for an hour, but leaves open the question how to weight the prices across hours. To be consistent with RTO-based average prices, one would take the simple average across the DPT hours.

In many cases, EQR data are not available for every hour in a DPT period, which has prompted several solutions. For example, the *Bluegrass* case involved the attempt by Louisville Gas and Electric and affiliate Kentucky Utilities (LG&E/KU) to acquire a three-unit simple cycle merchant facility interconnected with the LG&E system.[41] EQR data were not available in many hours, so the applicants supplemented the EQR data with system lambda data for the hours in which no EQR data were available and then took averages by period.[42] FERC accepted this substitution of lambda data for the missing EQR data.[43] When destination markets are adjacent to an RTO, the RTO prices may provide an avenue to infer that destination's hourly prices. In addition to providing hourly prices for generation units and loads within the RTO, RTOs also provide data on the value of selling to or importing from adjacent markets—including those areas without hourly prices. The RTO price for that market can be a proxy for the market price within the destination market.[44] For example, in the LG&E/KU application to modify a prior merger condition, the economist used MISO hourly prices plus the transmission rate to LG&E/KU as proxies for prices in the LG&E/KU balancing authority area (BAA).[45] Eight BAAs in the western United States now participate in the Western Energy Imbalance Market (EIM), and eleven more are scheduled to enter from 2020 through 2022.[46] Sales to the EIM are made in five-minute intervals and are included in EQR data. These data can now provide good hourly price data for otherwise traditional utility markets.

Another innovation in selecting representative market prices was expanding the period over which they are calculated. In early applications, prices were calculated over a single year.[47] A single year, however, may not be representative of typical market conditions. For example, an unusually cool summer could depress prices, or an unusually hot summer could inflate prices. In light of this issue, FERC required applicants to submit two years of price data when it formalized its

40. *Alabama Power Company et. al.*, 157 F.E.R.C. ¶ 61,019 (2016), at Appendix A, Step 7.

41. *Bluegrass Generation Company, L.L.C.*, 139 F.E.R.C. ¶ 61,094 (2012). The acquisition was approved by FERC, but with conditions to remedy market power concerns. *Id*. LG&E/KU did not accept the conditions. East Kentucky Electric Cooperative then acquired the plant. *See* LS Power, LS Power Announces Sale of Bluegrass Generation facility to East Kentucky Power Cooperative, July 29, 2015, available at https://www.lspower.com/ ls-power-announces-sale-bluegrass-generation-facility-east-kentucky-power-cooperative/.

42. *Id*. at P 26.

43. *Id.*

44. The RTO price can be adjusted by the transmission costs to move energy to and from the RTO.

45. Prepared Testimony of Julie R. Solomon, Louisville Gas and Electric Company and Kentucky Utilities Company, FERC Docket No. EC98-2-001, Aug. 3, 2018, at Exhibit LG&E/KU 2.3, p. 10. Solomon also examined PJM prices and found that they produced similar price levels. *Id.*

46. *See* CAL. INDEPENDENT SYSTEM OPERATOR, WESTERN ENERGY IMBALANCE MARKET, https://www.westerneim.com/Pages/About/default.aspx.

47. *See, e.g.*, Frankena (1997), *supra* note 33.

filing requirements in Order No. 642 in 2000.[48] Due to yearly variation in the calendar, the number of hours in a DPT period vary by year. So, the practice began to calculate average prices for each of the two years, and then average the results across the two years.

Another issue addressed by FERC is the transformation of historical average prices to forward representative market prices. In initial filings, applicants used the historical average prices.[49] Merger analysis, however, is forward looking, and FERC now requires applicants to adjust the historical prices to forward prices.[50] Some applicants have used expected price changes based on comparison of forward natural gas prices to historical gas prices and assumed heat rates to adjust electric power prices to the forward period.[51] Others have used forward natural gas prices and statistical analysis of the relationship between natural gas prices and electric power prices to estimate forward market prices.[52] The advantage of using a statistical relationship is that the transformation of natural gas price changes to electric power price changes is based upon observed evidence and not on an assumed relationship. Another approach is to use the DPT data to simulate market prices in the historical base period and in the forward period for each of the DPT periods, calculate the difference in prices, and then add the differences to the historical average prices.[53] Some have tried using forward price forecasts, but FERC has rejected these.[54] FERC's rejection is consistent on its preference for prices to be based on actual market prices.[55] Others have used forward prices from bilateral transactions and reported in trade publications.[56]

Whichever the source of representative prices, they must conform to objective measures of competitive reality. Morris observed a disconnect between market prices used in DPT analyses and the underlying generation data used in those analyses.[57] While actual prices can be observed (over some period), the underlying

48. C.F.R. § 33.3(d)(6) ("*Destination market price*. The applicant must provide, for each relevant product and destination market, market prices for the most recent two years. The applicant may provide suitable proxies for market prices if actual market prices are unavailable. Estimated prices or price ranges must be supported and the data and approach used to estimate the prices must be included with the application. If the applicant relies on price ranges in the analysis, such ranges must be reconciled with any actual market prices that are supplied in the application. Applicants must demonstrate that the results of the analysis do not vary significantly in response to small variations in actual and/or estimated prices.").

49. *See* Frankena (1997), *supra* note 33, at 60; Morris (2004), *supra* note 35, at Attachment 3, at 17.

50. *See* Letter from Steve P. Rogers to David Tewksbury, FERC Docket No. EC14-14-000, at 2 (Dec. 5, 2013) [hereinafter Rogers Letter]. Other DPT is also moved forward, including load levels, the generation fleet, and fuel costs.

51. *See, e.g.*, Affidavit of Julie R. Solomon, Bayou Cove Peaking Power, LLC *et al*., FERC Docket No. EC18-63-000, Exhibit JRS-4, at 8 (Feb. 7, 2018).

52. *See, e.g.*, Report and Affidavit of John R. Morris, NRG Energy Holdings, Inc. *et al*., FERC Docket No. EC14-14-000 (Oct. 24, 2013).

53. Morris (2019), *supra* note 31, Attachment JM-9, at 16-19.

54. *See* 136 F.E.R.C. ¶ 61,245, at PP 84, 123.

55. *Id*. at 121.

56. *See* Affidavit of Joseph Cavicchi and Joseph Kalt, FERC Docket No. EC10-77-000, at PP 35-36 (June 28, 2010). The analysis was implicitly accepted in *PPL Corporation*, 133 F.E.R.C. ¶ 61,083, at P 14 (2010).

57. John R. Morris, *Finding Market Power in Electric Power Markets*, 7 INT. J. ECON. OF BUSINESS 167 (2000) [hereinafter Morris (2000)].

data on generation costs are cobbled together based on various public sources. As a result, it is possible that observed price levels would be higher than the price levels implied from the generation data. In such cases, AEC will be overstated. Morris advocates using the implied prices from the underlying DPT generation data for a measure of market prices, rather than relying on historical price data.[58] Although this method has not been used in any merger filings known to the authors, in the *Bluegrass* case, FERC acknowledged that representative prices should produce implied capacity factors for generation units in a DPT analysis that correspond to actual observed capacity factors.[59] Capacity factors are the amount of energy generated as a percentage of the energy that could be generated if a unit operated at full output.[60] Implied capacity factors can be calculated based on whether a generation unit is economic in each of the DPT periods.[61] FERC concluded that supplementing EQR data with lambda data was more accurate because the implied capacity factors were closer to actual capacity factors.[62]

The historic perspective in this section shows that the identification of representative prices used in merger analysis has not been static. Over time, various issues have been raised, important points have been identified, and practitioners have attempted to develop and implement methods that best address them. It is in this historic context that this article seeks to empirically evaluate representative price calculation methodologies.

III. First Principles for Selecting Representative Market Prices

The representative market price is an essential input to calculate the size of suppliers in the destination market. The DPT is aimed at determining if a supplier can economically serve a given market based on market prices, dispatch costs, and transmission costs, then finds the size of the suppliers based on that economic capacity.[63] Suppliers can be included if they can deliver the product to the relevant customers at a cost no greater than 105% of the competitive price to the customer.[64] This section discusses the underlying theory for DPT analyses and derives a set of principles for selecting representative market prices.

To provide some framework, consider a standard depiction of supply and demand. Figure 1 shows an example of supply and demand conditions in a market. The upward sloping curve is the supply curve and the vertical line is the demand curve, which is often assumed to be fixed for a short-term hourly market. The intersection of the two curves determine the price level ($20/MWh in the figure) and the output level. Few end users for electricity face actual hourly electric power

58. *Id.* at 177.

59. *Bluegrass Generation Co., L.L.C.*, 139 F.E.R.C. ¶ 61,094, at P 26 (2012).

60. Fed. Energy Regulatory Comm'n, Market Assessments Glossary (Aug. 31, 2020), https://www.ferc.gov/industries-data/market-assessments/overview/glossary.

61. 139 F.E.R.C. ¶ 61,094, at n.45.

62. *Id.* at P 26.

63. The potential size of the supplier is the capacity that can delivered economically (accounting for load obligations when calculating AEC). This amount is credited for supplies within the destination market. Suppliers outside of the destination market receive pro-rata shares of the import capability. Order No. 642, *supra* note 3, at 31,894.

64. Order No. 592, *supra* note 4, at 31,130-131.

prices and instead pay a price that based on average costs over long periods that includes other costs as well. The result of average cost retail pricing is that from the perspective of generation companies supplying energy, demand is essentially fixed in any given hour. Because the demand is fixed, the demand level also defines the output level.

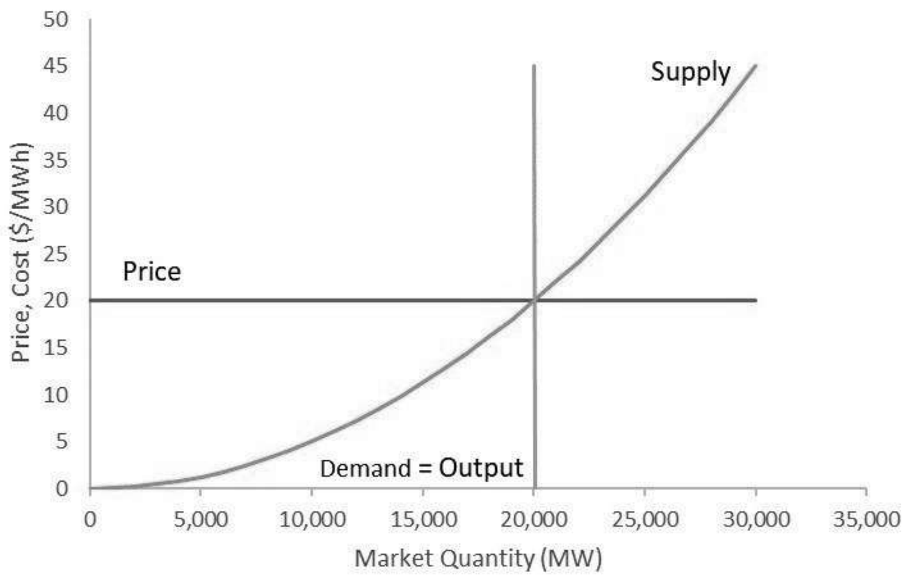

Figure 1: Supply and Demand Conditions in a Single Hour

One issue with DPT analyses is that the supply curve utilized does not necessarily match the actual supply curve in the market. Merger applicants do not know the availability and costs of generation for other suppliers, and FERC has specified specific methods for calculating the average availability of intermittent units such as hydroelectric, wind, and solar generation.[65] In addition, applicants typically "derate" the capacities of thermal generation units to take into account expected planned and forced outages during a season.[66] As a result, the supply curve in a DPT analysis is unlikely to match the actual supply curve during an hour.

Figure 2 shows the effects of having a supply curve that does not match the historical supply curve. In the figure, the estimated supply is more than the historical supply at any given price level. The increased supply necessitates at least

65. Order No. 642, *supra* note 3, at P 344.

66. 18 CFR § 33.3(d)(1) ("noting [f]or each generating plant or unit owned or controlled by each potential supplier, the applicant must provide . . . [s]ummer and winter capacity adjusted to reflect planned and forced outages and other factors, such as fuel supply and environmental restrictions.").

one of two possible adjustments in DPT calculations. The first potential adjustment is to lower the market price to the new price implied by the historical demand level intersecting the estimated demand curve. This implied price preserves the generation level at the historical generation level. Under the price adjustment option, the "representative market price" would not be a historical price, but the price internally consistent with the other DPT data. The second possible adjustment is to look for the intersection of the historical price level with the estimated supply curve and adjust generation to the implied generation level. The generation adjustment option preserves historical prices, but it is unlikely to do the same for generation. This is the adjustment many have made when using average historical prices and estimated supply curves. In the case of estimated supply being greater than historical supply, estimated generation will be greater than historical generation, producing more AEC than exists. If the estimated supply is less than the historical supply, the opposite would occur and the DPT calculations would underestimate AEC.

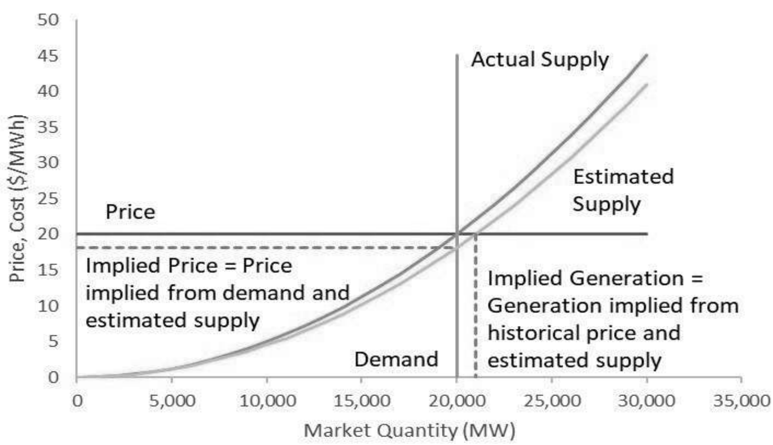

Figure 2: Effects of Estimated Supply Curves

Real-world supply curves can vary significantly for a given load level. Consider, for example, the summer peak period in PJM in 2018. Because the number of observations in the period is even, the median load level is the average of two observations, one from 9 p.m. on June 27 and one from 2 a.m. on June 29.[67] The two prices are $39.43/MWh and $29.10/MWh, a range of 30% of the midpoint![68] It is not clear which price is more representative of the median load level. Limiting the price sample to prices in the thirty hours with loads closest to the median load level, prices range from $27.43/MWh to $56.68/MWh, with an average of

67. Hitachi-ABB, VELOCITY SUITE, *PJM Historical Zonal Load*, 2018.

68. Hitachi-ABB, VELOCITY SUITE, *ISO Real Time & Day Ahead LMP Pricing - Hourly*, 2018

$34.87/MWh and a median of $32.75/MWh.[69] This range in prices ($19.25/MWh) is 61% of the median price compared to the corresponding range of loads of only 1% of the median load. Therefore, prices can, and often do, vary significantly in electric power markets for comparable load levels, which is to say the supply conditions can vary significantly for similar load levels.

The DPT is designed to identify when an acquisition might create or enhance market power. Market power is the ability profitably to restrict output and thereby raise market prices.[70] In electric power markets, especially the centrally-dispatched RTOs, generation owners must select combinations of generation levels at various price levels.[71] For a fleet of generation units, the owner provides a supply schedule to the market operator.[72] The market solution concept for this type of competition is known as supply function equilibrium (SFE).[73] Multiple solutions many be obtained for the SFE problem, ranging from perfectly competitive outcomes to the Cournot solution.[74] Rather than consider the total market solution, we can examine the incentives of an individual company, such as the post-merger entity.[75] The optimal offer for a unit at the company is given by:

$$\textit{Offer} = \textit{Marginal Cost} + \textit{Price Effect} \times (\textit{Inframarginal Energy} - \textit{Obligations}) \quad (1)$$[76]

In words, equation (1) states that the generation offer is equal to the marginal cost plus the profit depressing effect of clearing the unit. That profit depressing

69. *Id*. Because this sample is taken from the middle of the load distribution, it is not surprising that the average and median in the sample are not substantially different from those of the entire period. Across all observations in the period, the average price is $34.89/MWh, and the median is $31.55/MWh.

70. *See, e.g.*, Morris (2004), *supra* note 35, at 10 ("Market power is the ability of a seller or group of sellers profitably to restrict output and to maintain prices above competitive levels for a significant period of time."); Order No. 592, *supra* note 4, at 68,607 ("[A]n entity with market power can raise the price of one product and buyers would have a limited ability to shift their purchases to other products."); U.S. DEP'T OF JUSTICE, 1992 MERGER GUIDELINES [hereinafter 1992 Guidelines] ("Market power to a seller is the ability profitably to maintain prices above competitive levels for a significant period of time.").

71. Richard J. Green & David M. Newbery, *Competition in the British Electricity Spot Market*, 10 J. POL. ECON. 929 (1992).

72. *Id.*

73. *Id.*

74. Paul D. Klemperer & Margaret A. Meyer, *Supply Function Equilibria in Oligopoly under Uncertainty,* 57 ECONOMETRICA 1243, 1243 (1989). A Cournot solution occurs when sellers select quantities so that no seller has an incentive to sell a different quantity given the quantities selected by the others. *See* ANTOINE AUGUSTIN COURNOT, RESEARCHES INTO THE MATHEMATICAL PRINCIPLES OF THE THEORY OF WEALTH (Nathaniel T. Bacon trans., Macmillan 1897) (1838); John F. Nash, *Equilibrium Points in N-Person Games*, 36 PROC. NAT'L ACAD. SCI. U.S. 48 (1950).

75. *See, e.g.*, Romkaew Broehm, Jeremy Verlinda, and James Reitzes, Comments, FERC Docket No. RM16-021-000 (Nov. 28, 2016), for a discussion of the profit-maximizing offers of a single generation owner.

76. Let new profits for firm i be represented by $\pi_i = p(l,g,q_i)(q_i - O_i) - C(g,q_i)$, where p is the market price—a function of market load l, fuel (e.g., natural gas) price g, and the output of generation owner q_i. O_i is the forward sales obligation, so the difference between q_i and O_i is the additional output associated with the new profit. C is the cost of production, which, like p, is a function of g and q_i. The additional profit is the product of the market price, p, and the additional output, $q_i–O_i$, minus the cost associated with the new output quantity C. Profits are maximized when the first derivative of the profit function with respect to quantity reaches 0, or $\partial\pi_i/\partial q_i = \partial p/\partial q_i(q_i - O_i) + p - \partial C/\partial q_i = 0$. Solving for p recognizing that the offer is equal to price of a marginal unit, gives *Offer* $p = \partial C/\partial q_i - \partial p/\partial q_i(q_i - O_i)$. This gives the relationship in equation (1). *See id.* at app. B(I).

effect is the price effect from not clearing the unit multiplied by the net position assuming the unit does not clear. The price effect is the absolute value of the slope of the company's demand curve.[77] The price effect is multiplied by the net position of the company if the unit does not clear. The net position is the inframarginal energy (i.e., the generation already clearing the market) minus the prior obligations. The obligations represent all the prior sales at prices that will not be affected by changing output.

Equation (1) indicates that offers will increase as marginal costs increase, price effects increase, and inframarginal energy increases, while offers will decrease as the amount of prior obligations increase. The potential effects of a merger can be seen in the equation. Efficiencies that may lower marginal cost are captured in the marginal cost term.[78] Potential price-increasing effects from a merger are captured in the price effect term and the infra-marginal energy term. A merger can decrease the competition faced by the pre-merger firms, which increases the potential price effect from increased offers, raising the incentive for higher offers. A merger of generation owners also increases inframarginal energy. This gives an incentive for higher offers because clearing the marginal unit decreases price over a greater amount of cleared generation. Consequently, the merged owner will demand greater compensation before clearing the unit. Finally, the obligations term captures effects from changing load obligations. It is well documented that load obligations and other forward sales diminish market power.[79] Therefore, combining load obligations decreases market power.

Equation (1) can be rearranged to form a Lerner Index, a well-known measure of market power.[80] Recognizing that for the marginal generation unit the offer is equal to price, the Lerner Index is:

$$\begin{aligned} L &= \frac{Price - Marginal\ Cost}{Price} \\ &= \frac{1}{|Firm\ Elasticity|} \times (Inframarginal\ Energy - Obligations) \end{aligned} \tag{2}$$

77. Even with perfectly inelastic market demand (e.g., see Figure 1), the demand curve for a single generation owner is downward sloping because of the competition from rival generation companies. Because the company demand is downward sloping by clearing an additional unit the company will reduce the market price by some amount. The company will want to be compensated for the price depressing effect of selling more. Hence, it is necessary to use the absolute (positive) value of the demand curve slope.

78. For more robust discussions of how efficiencies can be incorporated in marginal cost and how they affect post-merger prices, see J. Dutra & T. Sabarwal, *Antitrust analysis with upward pricing pressure and cost efficiencies*, 15(1) PLOS ONE e0227418 (2020).

79. *See* Frank Wolak, *An Empirical Analysis of the Impact of Hedge Contracts on Bidding Behavior in a Competitive Electricity Market*, 14(2) INT'L ECON. J. 1 (2000). For the extent of forward sales and hedging by electric generation companies, *see* Market Power Rebuttal Testimony of Michael M. Schnitzer, In the Matter of the Merger of Exelon Corporation and Constellation Energy Group, Inc., Public Service Commission of Maryland, Case No. 9271 (Oct. 17, 2011).

80. A.P. Lerner, *The Concept of Monopoly and the Measurement of Market Power*, 1 REV. ECON. STUD. 157 (1934).

As been shown elsewhere, the Lerner Index can be related to the HHI measure of market concentration,[81] which FERC uses to screen mergers. The HHI can also be related to social welfare and the desirability to take government action, such as limiting mergers and acquisitions.[82] Hence, it provides a good basis for evaluating steps in the DPT methodology.

Equation (2) suggests it is likely better to use implied prices from DPT data instead of historical prices. The equation divides the measure of market power into two parts. The first part is the firm demand elasticity. The main driver of the firm elasticity is the supply availability from competitors. Although the value can change at different places along a supply curve (e.g., jumping from nuclear energy to coal or gas-fired energy), *a priori* there is no reason to believe that this value would change significantly with small changes in price or generation levels.[83] For estimating market power, elasticity can be considered fixed for any given time period and load level. The second term is a firm's net hourly energy position divided by the energy it generates. As discussed above, using historical prices with an estimated supply curve is likely to over- or understate the market's true generation level. This market level misspecification results in erroneous generation estimates for individual firms. These errors can be minimized by using the DPT's implied prices and attempting to match historical generation levels within the analysis.

$$L = \left|\frac{\%\, Change\ in\ Price}{Change\ in\ Quantity}\right| \times (Inframarginal\ Energy - Obligations) \qquad (3)$$

As before, this can be thought of as dividing the measure of market power into two parts. The first part is the ability to raise prices per unit change in output. The larger the effect, the greater the ability of the seller to raise market prices. The second part gives the incentive to raise market prices, which is the energy produced less the prior obligations to sell energy—the open market position. The greater the apparent open market position, the greater the market power—holding other factors constant.

Without transaction-specific information it is impossible to determine the effects of higher (or lower) measures of the relevant market price. In general, a higher price increases the likelihood that an applicant has AEC, but its competitors are also more likely to have additional AEC.

Given the HHI-based assessment methodology, the results of the screening method depend on the change in the size of the applicants relative to the change in the size of other suppliers. In RTO markets, higher representative prices often

81. *See, for example*, John Kwoka, *The Herfindahl Index in Theory and Practice*, 30 ANTITRUST BULL. 915, 924-5 (1985); Keith Cowling & Michael Waterson, *Price-Cost Margins and Market Structure*, 43 ECONOMICA 267, 268 (1976).

82. *See, e.g.,* Robert D. Willig, *Merger Analysis, Industrial Organization Theory, and Merger Guidelines*, BROOKINGS PAPERS ON ECONOMIC ACTIVITY: MICROECONOMICS, (1991) at 281; Janusz Ordover et al., *Herfindahl Concentration, Rivalry, and Mergers*, 95 HARVARD L. REV. 1857 (1982); Robert E. Dansby and Robert D. Willig, *Industry Performance Gradient Indexes*, 69 AM. ECON. REV. 249 (1979).

83. *See generally* Janusz Ordover et al., *supra* note 82, at 1867.

reduce market concentration and do not appreciably increase the risk of screen violations because most competitors are already within the market and their AEC increases along with applicants. Figure 3 shows a scatter plot of the relationship between HHI levels on the vertical axis and representative price level on the horizontal axis for the PJM RTO. Each dot represents a price level and the resulting market concentration in a DPT period.[84] For each of nine DPT periods with 2017-2018 price data, Figure 3 shows market concentration for the 10th percentile through the 90th percentile prices. So, in total, there are eighty-one dots in the figure. It shows that higher price levels can substantially reduce market concentration, especially in the off-peak periods.[85]

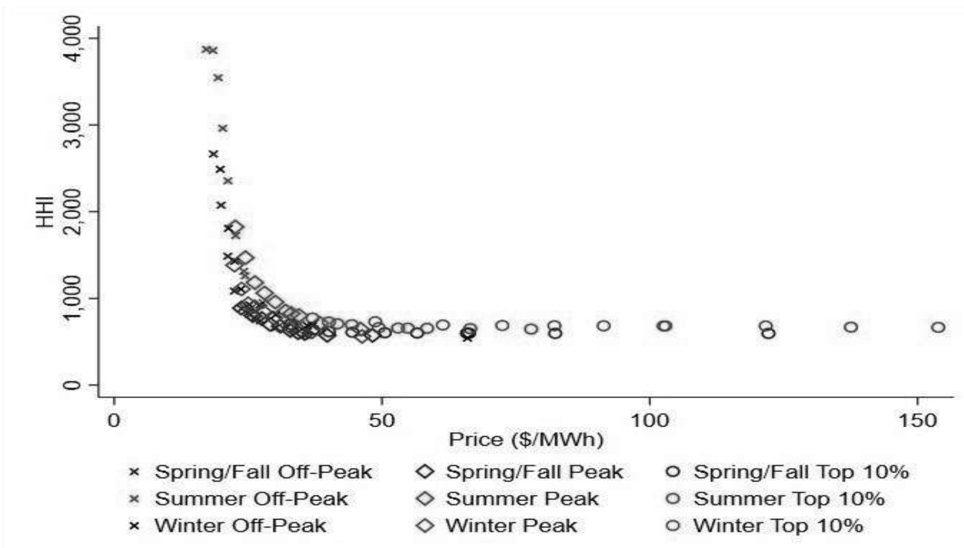

Figure 3: Relationship between market concentration and price level for AEC in PJM

In traditional markets with vertically integrated utilities, higher representative prices often increase HHI levels and the likelihood of HHI screen violations. Higher prices often increase the size of the applicant within the market (give the applicant more AEC), but the combined size of most competitors—located outside of the market—does not expand because the methodology limits outside suppliers by import capability. [86] Figure 4 shows a scatter plot between the HHI and market

84. The HHI levels were calculated using standard "off the shelf" generation cost, generation capability, and demand (load) data maintained by Economists Incorporated. The HHI's were calculated based on data for PJM and for the first-tier areas. For a more general description of the methodology, see Morris (2019), *supra* note 31, at Attachments JM-9 and JM-10 of the same report.

85. The figure will show different HHI's for similar price levels because it includes results from nine different DPT periods. For example, Spring/Fall Top 10% 40th percentile prices might be similar to Summer Peak 60th percentile prices but have different HHI levels due to the differences in generation availability across seasons.

86. Imports are limited by the both the transfer limits from other areas to the destination market and a simultaneous import limit required by FERC. *See* 18 CFR § 33.3(c)(4)(i)(c) ("Each potential supplier's economic

prices for the Tampa Electric balancing area in Florida in the same format as Figure 3. Unlike Figure 3, Figure 4 has no well-defined pattern between the HHI and the price level. In some DPT periods, higher prices raise market concentration because Tampa Electric is the largest supplier and higher prices increase its AEC while import limits prevent commensurate AEC increases for other suppliers.

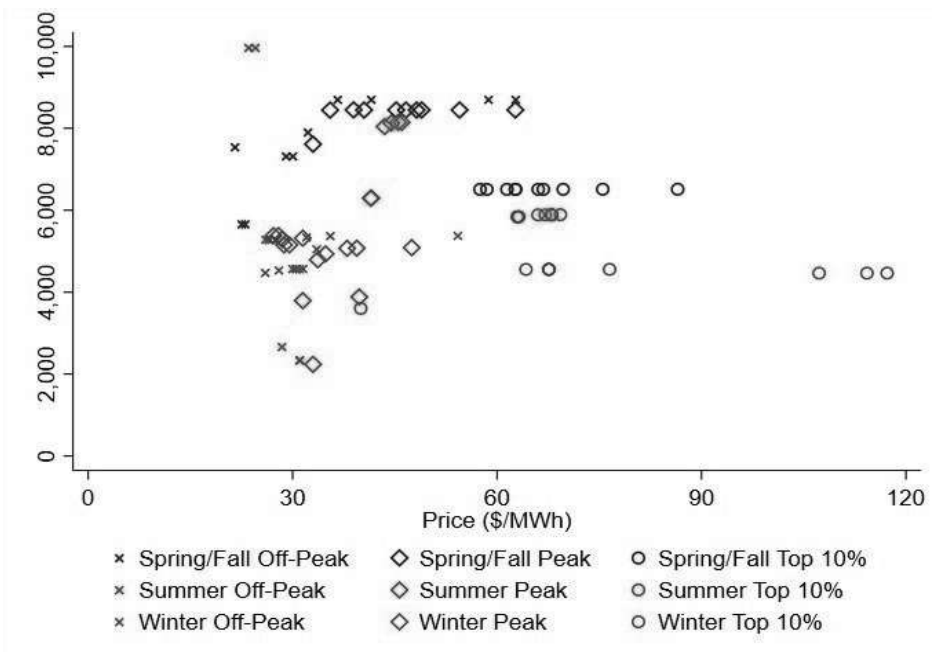

Figure 4: Relationship between market concentration and price level for AEC in Tampa Electric Balancing Area

IV. THE SKEWNESS OF ELECTRIC POWER PRICES

Basing representative market prices on average historical prices has two problems. First, as discussed in section III, the historical price data does not necessarily match the other data in the DPT analysis. But there is a second flaw with

capacity and available economic capacity (and any other measure used to determine the amount of relevant product that could be delivered to a destination market) must be adjusted to reflect available transmission capability to deliver each relevant product. The allocation to a potential supplier of limited capability of constrained transmission paths internal to the merging entities' systems or interconnecting the systems with other control areas must recognize both the transmission capability not subject to firm reservations by others and any firm transmission rights held by the potential supplier that are not committed to long-term transactions. For each such instance where limited transmission capability must be allocated among potential suppliers, the applicant must explain the method used and show the results of such allocation."); *See* Order No. 697, *supra* note 14, at 384 ("For the reasons stated herein regarding the need to as accurately as possible account for transmission limitations when considering power supplies that can be imported into the relevant market under study, the Commission adopts the requirement for use of the SIL [Simultaneous Import Limit] study as a basis for transmission access for both the indicative screens and the DPT analysis.").

average prices: Because price distributions are positively skewed, average prices might be substantially greater than the most common prices during a DPT period.

A two-paragraph primer on statistics helps to understand the issue. The statistical concept of a representative price is captured by what statisticians and economists call central tendency. But three measures of central tendency exist: mode, median, and mean. The mode is the most common value, the median is the value in the middle, and the mean is the arithmetic average. Each of these have advantages over the other depending upon the data and the use. When distributions of value are perfectly symmetric, the mode, median, and average are the same values and it does not matter which measure is used. But electric power prices are typical highly skewed with a positive skewness.[87] To understand skewness, it helpful to understand how statisticians describe distributions of data. They often speak of four "moments" of a distribution. The first moment measures the expected value, which is the mean. The second moment measures the distribution, and it is the standard deviation. The third moment is the measures whether the data are symmetric or asymmetric around the mean, and that is the skewness. The fourth moment measures how peaked the data are around centralized values, and that is a kurtosis.

The skewness of a set of observations measures whether prices are symmetric or asymmetric around the means and is measured as the third moment of the distribution, mathematically given (for a population) by $\Sigma(x_i - \overline{x})^3/ns^3$ where $\overline{x}$ is the average, n is the number of observations, and s is the standard deviation.[88] When skewness is negative, the distribution is skewed to the left and in most cases the average will be less than the median value. When looking at a negatively skewed distribution, the observer sees more observations to the left of the peak than the right. When skewness is a positive, the distribution is skewed to the right and in most cases the average will be greater than the median value. When looking at a positively skewed distribution, the observer sees more observations to the right of the peak than the left. When skewness is within +/- 0.5, then the data are approximately symmetric; when between the -1 and -0.5 or 0.5 and 1 the data are moderately skewed; and when less than -1 or greater than +1, the data are highly skewed.[89]

Figure 5 shows a histogram of the prices for the Southwest Power Pool (SPP) in the 2017 Spring/Fall Peak period, which is a typical example of highly skewed electric power prices.[90] Here, the average price level is about 22% higher than the median price level; as discussed below, around 22% is the typical amount the average diverges above the median. This distribution is also typical in that it has a large tail with some prices over $400/MWh compared to the average of about $27/MWh. As can be seen in Figure 5, relatively few observations with very high

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87. Rafal Weron, *Research Report HSC/05/2 Heavy tails and electricity prices* 6 (2005), http://www.im.pwr.wroc.pl/~rweron.

88. *See, e.g.*, JOHN E. FREUND AND RONALD E. WALPOLE, MATHEMATICAL STATISTICS 137-148 (3d ed. 1980).

89. M.G. BULMER, PRINCIPLES OF STATISTICS 66 (Dover 1979).

90. Hitachi-ABB, VELOCITY SUITE, *ISO Real Time & Day Ahead LMP Pricing - Hourly*, 2017.

prices (*e.g.*, over $100/MWh compared to a median of $22/MWh) drive the average price significantly above the median. But even excluding the prices above $100/MWh, the distribution would still be skewed and the average would be above the median. Therefore, average prices levels can lead to representative prices that above the levels that most commonly occur during a DPT period.

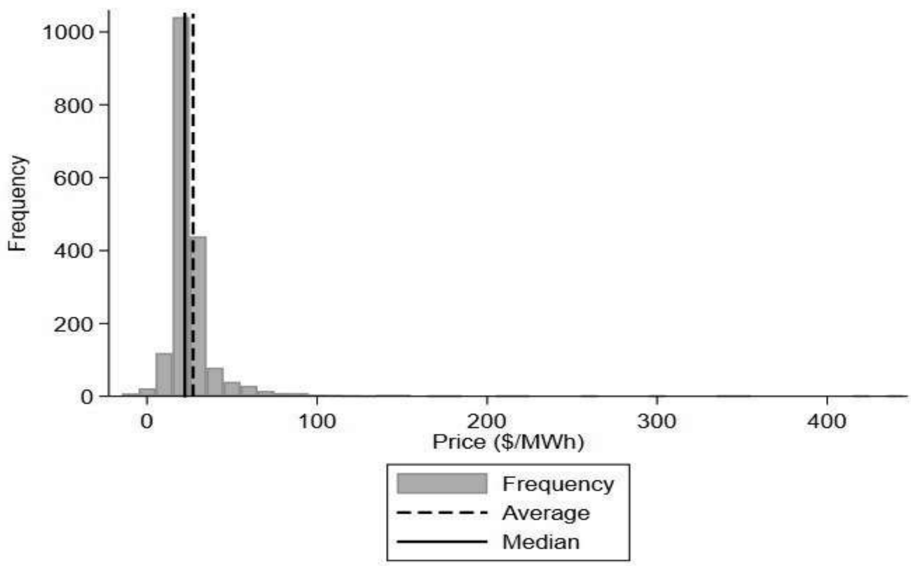

Figure 5: Distribution of SPP Spring Peak Prices[91]

The skewness shown in Figure 5 is not uncommon, as shown in Table 1. The table shows summary skewness measures for each of the RTOs in the United States. For each RTO, it shows the minimum measure, average, and maximum measure of skewness across eighteen periods. Although prices can be negatively skewed, typically prices exhibit positive skewness in which the averages are greater than the median values. In fact, prices are skewed negative in only three of the 126 periods. Each of these periods are off-peak, when excess supplies due to necessary commitments of generation for peak periods and the presence of wind or solar generation can drive prices extremely negative.[92] In all other periods, prices are highly skewed positively.

91. *Id.*

92. *See, e.g.,* GRAEME R.G. HOSTE ET AL., MATCHING HOURLY AND PEAK DEMAND BY COMBINING DIFFERENT RENEWABLE ENERGY SOURCES 2 (2020).

RTO	Minimum	Average	Maximum
CISO	-1.5	4.3	11.4
ERCOT	-0.5	9.9	30.8
ISONE	-0.3	4.2	27.3
MISO	2.0	5.7	13.4
NYISO	0.6	5.7	22.6
PJM	1.3	3.3	6.5
SPP	3.2	6.0	9.2

Table 1: Summary of RTO Price Skewness

The figures in Table 1 are calculated as follows. The table is based on calculating skewness measure for nine DPT periods for each RTO for 2017 and 2018.[93] Because the DPT periods are calculated by year and there are two years of data, each row of Table 1 is based on analyzing eighteen periods for each RTO.

From these data, we see that skewed price distributions can increase the average price level significantly above the median price level. We have also shown that different price levels can either artificially lower or artificially increase the HHI. Therefore, selecting the most appropriate measure of a representative price is an important element of FERC's competitive assessment methodology. We now examine whether the skewness of the prices makes a meaningful difference between average and median levels. If the differences are minor, then we would have less reason to question the current practice of relying on the historical average price. But if the differences between the two are great, that would suggest additional research is warranted to determine which price level is more appropriate when attempting to measure market concentration by price and load levels.

To measure the difference, we calculate the average and median price levels for each of the 126 market-periods discussed above. From these, we then calculate the difference between the average and median as a percentage of the median price. Table 2 presents a summary of the percentage differences in a format similar to Table 1, across the 126 periods for each RTO. In all cases, the average is

93. Although the DPT analysis is done for 10 periods, one period (typically the highest load conditions in summer) consists of either a single hour or a group of ten hours. Rogers Letter, *supra* note 50, at n.3 (specifying the top summer period as the single highest load hour or top 1% of on-peak summer hours based on load levels). This period is too small for meaningful analyses, so the analysis covers nine periods, consisting of the top 10% of on-peak hours, the remaining on-peak hours, and off-peak hours in each of the three seasons (spring/fall, summer, and winter).

greater than the median. This is true even in the three cases that showed some negative skew, although the differences are trivial in two of the three cases (CISO and ERCOT). But average prices typically are about 22% more than median prices. Moreover, one case–summer top 10% in CISO–the average price of \$135/MWh is more than double the median price level of \$58/MWh. These differences are great enough to make substantial differences in HHI calculations. We also find that in 117 of the 126 cases the average was statistically different from the median based upon a two-tailed test at a 5% significance level.[94]

RTO	Minimum	Average	Maximum
CISO	0.7	27.7	134.7
ERCOT	0.1	30.1	84.8
ISONE	4.5	21.3	57.1
MISO	7.6	16.7	42.7
NYISO	4.0	20.4	72.3
PJM	7.6	17.9	65.6
SPP	4.1	18.7	38.9

Table 2: Summary of Percentage Differences between Average and Median Prices by RTO

The highly skewed distribution of prices as revealed in Figure 5 is representative of most price distributions we examined. The right tail is very long, with some extreme observations and atypically high prices. We tested if excluding these outliers might make the differences between average and median price levels disappear. To identify outliers, we utilized Tukey's Fence.[95] Specifically, we dropped prices less than 1.5 times the interquartile range below the first quartile and more than 1.5 times the interquartile above the third quartile. Table 3 shows a summary of the percentage differences between averages calculated after excluding outliers and the medians. The average percentage difference is 3.4% (averaged over the RTOs) compared to 22% for prices including the outliers. But substantial differences can remain, with the revised average percent differences falling as much as 6.7% less than the median to 25.5% more than the median. In thirty-six of the 126 periods, the revised average is more than 5% greater than the median, and in thirty-

94. The significance level gives the probability that the we would conclude that the two values are different when in fact they are the same. The 5% threshold is standard in scientific work and has been accepted in courts. *See, e.g.*, Palmer v. Shultz, 815 F.2d 84, 92 (D.C. Cir. 1987) ("'the .05 level of significance . . . [is] certainly sufficient to support an inference of discrimination'") (quoting Segar v. Smith, 738 F.2d 1249, 1283 (D.C. Cir. 1984), *cert. denied*, 471 U.S. 1115 (1985))); United States v. Delaware, 2004 U.S. Dist. LEXIS 4560 (D. Del. Mar. 22, 2004) (stating that .05 is the normal standard chosen).

95. John W. Tukey, EXPLORATORY DATA ANALYSIS 27-47 (Addison-Wesley 1977). Let Q_1 denote the first quartile (*i.e.*, the 25th percentile) and Q_3 to denote the third quartile (*i.e.*, the 75th percentile). Then outliers occur when $x < Q1 - 1.5(Q3 - Q1)$ and when $x > Q3 + 1.5(Q3 - Q1)$. This is the most common version of Tukey's Fence.

four of the thirty-six, the difference is statistically significant at the 5% level. Based upon these data, we conclude that excluding outliers does not make the average prices comparable to the median prices.

RTO	Minimum	Average	Maximum
CISO	-1.5	3.5	16.7
ERCOT	-4.0	2.5	10.9
ISONE	-4.2	7.2	25.5
MISO	-0.1	3.7	11.4
NYISO	-6.7	2.3	12.7
PJM	0.6	3.4	9.9
SPP	-4.4	1.1	8.9

Table 3: Summary of Percentage Differences between Average and Median Prices by RTO, Dropping Outliers

V. EVALUATING METHODOLOGIES FOR SELECTING REPRESENTATIVE MARKET PRICES

The most appropriate method of calculating market prices depends on which method better represents market conditions. In section III, we show that how well the methodology replicates historical generation levels a fundamentally sound criterion for evaluating different price selection methodologies. For a single market with no imports or exports, the determining generation levels is straightforward because the load (demand) determines the output level. Actual markets, however, are interconnected and have imports and exports so that generation output can be more or less than the load level.[96] Fortunately, RTOs now post hourly generation levels.[97] These output levels can be matched to the hours defining the DPT periods, and we can calculate average historical generation levels during DPT periods.[98] These historical generation levels are our benchmark for judging representative market price selection methodologies.

We compare these historical generation levels against implied generation based on DPT generation data. For the implied generation levels, we use Hitachi-ABB data for generation unit heat rates, publicly available data on fuel costs, and

96. *See, e.g.,* ENERGY INFO. ADMIN., ELECTRICITY EXPLAINED: FACTORS AFFECTING ELECTRICITY PRICES (Dec. 16, 2020), https://www.eia.gov/energyexplained/electricity/prices-and-factors-affecting-prices.php.

97. The Energy Information Administration (EIA) now requires balancing authority operators to report hourly generation by fuel type. This now provides an alternative source of hourly generation data. *See* ENERGY INFO. ADMIN., FREQUENTLY ASKED QUESTIONS: DOES EIA PUBLISH DATA ON PEAK OR HOURLY ELECTRICITY GENERATION, DEMAND, AND PRICES? (July 15, 2020), https://www.eia.gov/tools/faqs/faq.php?id=100&t=3.

98. Our examination of historical generation levels indicates that generation levels typically are not very skewed in DPT periods and the average and median are similar.

estimates of variable operations and maintenance expenses.[99] From these data, we estimate a dispatch cost and compare it to the putative market prices to see whether a unit is "on" or "off" during a DPT period. For unit capacity, we take publicly available capacity and then "derate"—that is, reduce the size—of the unit to account for planned and forced outages based on data reported by NERC in its Generation Availability Data System (GADS).[100] Although these outage data are not unit-specific, over the hundreds of units in an RTO they reasonably reflect generation availability on average.

We use four alternative measures of representative market prices: (1) implied prices based upon the historical generation levels and generation data in the DPT analysis; (2) modeled prices based upon a simple dispatch model matching supply to the demand in the DPT data; (3) median historical price levels by DPT period; and (4) average historical price levels by DPT period. The implied prices match historical generation levels almost perfectly because they are calculated to match the generation levels.[101] Model prices should also be close to the actual model levels because the main difference between actual and modeled output will be driven by imports and exports, which typically are small compared to the market size.[102] For reasons discussed in Morris (2000) and above, the median prices and average prices may produce DPT output levels substantially different from reality. In short, the underlying generation data in the DPT analysis may be substantially different from actual costs of operating an electric power system in the real world.

Table 4 gives annual average prices by RTO for each of the four pricing methodologies. The first column gives the RTO and the following columns give averages for the Implied, Model, Median, and Average methodologies. Annual average prices were calculated by weighting each DPT period by the number of hours in the period. Because the off-peak periods constitute over one-half of the hours in a year, the averages are heavily weighted to the off-peak periods. Nevertheless, the averages provide some indication of the range of results of the different methodologies. The implied price methodology produces the highest average for three RTOs: CISO, ISONE, and NYISO. The model methodology never produces the highest prices, but produces the lowest annual average for ERCOT, ISONE, and MISO. Interestingly, despite the skewness of historical price data, the median produces the highest annual average for three RTOs: MISO, PJM, and SPP. Yet, the median produces the lowest overall average across the RTOs. The average methodology produces the highest average for ERCOT, and overall.

99. These are data required in a DPT filing. 18 C.F.R. § 33.3(d)(2) (2000). For natural gas costs, we used averages of daily natural gas prices in each of the DPT periods.

100. Derating is required in a DPT analysis. 18 C.F.R. § 33.3(d)(1).

101. They do not match perfectly in all periods because many MW of capacity can have the same dispatch cost in DPT data. This creates as small range of uncertainty of output levels for a given price level. For example, if the price of $25/MWh is necessary to match an output level of 20,000 MW and there are 1,000 MW of capacity at $25/MWh, then the DPT capacity at that price can range from 20,000 MW to 20,999 MW.

102. CISO is an exception to this as imports account for as much as 40% of its demand in some hours. *See* Morris (2000), *supra* note 57.

RTO	Implied	Model	Median	Average
CISO	45.16	39.16	36.23	39.46
ERCOT	25.54	22.29	24.38	25.55
ISONE	39.62	31.30	38.74	37.91
MISO	26.06	25.90	29.36	25.50
NYISO	36.78	28.03	33.56	34.58
PJM	27.69	27.91	32.59	28.77
SPP	22.39	23.24	24.66	22.36
All	31.40	31.04	27.84	31.82

Table 4: Comparison of Annual Average Prices from Implied, Model, Median, and Average Methodologies

We have data for seven RTOs and nine time periods for each.[103] This gives sixty-three "tests" of the how well a price level predicts the historical generation level in the RTO. We utilize two metrics to determine which methodology fits best. First, we count which methodology best predicts generation levels among the sixty-three tests. The best methodology could be viewed as the one that predicts best most often. Second, we use a form of relative absolute error (RAE) known as Theil's U.[104] The RAE is unitless and gives the error as a fraction of the actual average value. We multiply this value by 100 to place it in percentage terms. For example, a RAE of thirty means that errors on average are 30% of the actual values.

Based upon the "closest most often" criteria, the implied price methodology has the best fit and the average price methodology is the worst. Table 5 shows the counts of the representative price methodology that most closely predicts the average generation level during a DPT period. The first column gives the methodology: implied, model, median, and average. The second column gives the results when all four methodologies are compared. The implied price methodology is the

103. Because DPT data are averaged over two years, we have only nine periods per RTO instead of the 18 per RTO used in section IV.

104. The RAE is calculated as:

$$RAE = \sqrt{\frac{\sum_i^n (p_i - a_i)^2}{\sum_i^n a_i^2}}$$

where p_i is the predicted value, a_i is the actual value, and n is the number of observations. *See* H. Theil, ECONOMIC FORECASTS AND POLICY (Amsterdam: North Holland, 1958), at 31-42; *See also* Stephanie Glen, *U Statistic: Definition, Different Types; Theil's U*, STATISTICS HOW TO (Jan. 12, 2017), https://www.statisticshowto.com/u-statistic-theils/.

closest most often, in fifty-six of the sixty-three tests. This is not surprising because the methodology is designed to produce a price level that closely matches the implied generation to the average historical generation level. Despite this design, the model prices are closer in six of the sixty-three tests and identical to the implied methodology in three, which produces a total of nine closest.[105] The third column excludes the implied price methodology to compare the model, median, and average methodologies. In this case, the model prices produce the generation levels closest to actual in fifty of sixty-three cases. The fourth column excludes the model methodology to compare the implied, median, and average methodologies. In this comparison, the implied prices produce the closest to historical generation levels in sixty-one of sixty-three of the tests, and the median methodology is closest in two. Finally, the fifth column show a head-to-head competition between median and average price levels. In this case, median prices are closest in forty-six of the sixty-three periods, while average prices produce generation levels closer to actual in only seventeen periods. When summing across the columns, the average price methodology has the lowest total. In other words, the methodology that is most used in DPT analyses is the worst at matching implied generation levels in the DPT to actual generation levels.

Comparison	Implied	Model	Median	Average	Total
All Four Methodologies	56	9	1	0	66
Model, Median & Average	–	50	8	5	63
Implied, Median & Average	61	–	2	0	63
Median & Average	–	–	46	17	63

Table 5: Number of tests each methodology predicts closest to actual generation levels

Our other criterion is the accuracy of the predicted DPT generation levels for each price methodology as measured by the relative absolute error. Table 6 shows the relative absolute errors on average for the RTOs and across all the RTOs. In each case, the relative absolute error for the implied price methodology is very small compared, ranging from 0 to 1.8%. Next closest is the model price methodology. In some RTOs (*e.g.*, ERCOT, MISO, PJM, and SPP) the model produced implied generation levels close to the actuals. Even when the model produced substantial error—*e.g.*, 19.7% in CISO—the model was much more accurate than the median and average methodologies based on actual price data. Overall, the average error for median prices was 26.7% and the average error for average prices was 30.3%. Once again, the traditional methodology produces the worst results, with average errors of 30.3% and errors for one RTO of 42.2%.

105. Because of the three ties for closest between the implied and the model methodologies, the total in the table is 66 instead of 63 for the second column.

RTO	Implied	Model	Median	Average
CISO	0.6	19.7	33.7	35.6
ERCOT	0.8	0.9	35.2	42.2
ISONE	1.8	15.5	30.8	33.4
MISO	0.3	6.4	32.8	38.6
NYISO	1.0	9.8	29.5	30.6
PJM	0.3	6.1	18.4	19.4
SPP	0.7	1.4	31.3	32.8
All	0.5	6.8	26.7	30.3

Table 6: Relative absolute error for each methodology by RTO

Another metric to measure the reasonableness of a methodology for selecting representative market prices is to examine the percentage of the year captured in the price sensitivity analysis. Recall that FERC requires that the HHI also be calculated at prices above and below the representative prices selected by the applicants.[106] The typical practice is to use prices 10% above and below the representative price.[107] This gives a range of prices over which the analysis covers, and this range of prices in turn defines a set of hours over which are implicitly covered in each DPT period and the year. For example, take the SPP Spring period in 2017 used in Figure 5. The median price is $22/MWh, which gives the range of $19.80/MWh to $24.20/MWh hour. All the prices that occur in this range comprise 27% of the DPT period. The average price is $27/MWh, which produces a range of $24.30/MWh to $29.70/MWh. Because the average price is higher than the median, the range is wider ($5.40 vs. $4.40), but because the average is further away from the middle of the distribution of prices, the range of prices for the average covers only 20% of the DPT period, which is less than the hours covered by the median range. Because range of hours covered by the price sensitivity (based on historical prices) is greater for median prices than for average prices, the median prices can be considered a superior measure of representative prices.

We applied this exercise to all the DPT periods for all the RTOs and methodologies for the 2017 and 2018 years, and the summary is in Table 7. It shows the percentage of the years that are within the price ranges calculated based upon each price methodology. In all cases, the range from the median price methodology covers more of the years than the range established by the other methodologies. On average, the median ranges cover about 30% more hours than do the

106. 18 C.F.R.§ 33.3(d)(6) (2019).

107. This is the range that has been required by FERC Staff. *See* 136 F.E.R.C. ¶ 61,245, at P 48 ("Applicants were directed to provide price sensitivity analyses for the Duke Energy Carolinas, Progress Energy Carolinas-East, and Progress Energy Carolinas-West BAAs under two different scenarios – a 10 percent price increase and a 10 percent price decrease.").

average ranges. The results provide another reason to favor median price levels over average price levels if historical prices are to be used as the basis of representative market prices. The implied and model methodologies on average also cover more hours than do average prices. This is to say that those methodologies often produce prices closer to the center of the price distribution than does the averaging methodology.

RTO	Implied	Model	Median	Average
CISO	12.9	14.3	19.4	18.0
ERCOT	24.2	24.3	30.4	26.2
ISONE	13.9	13.7	17.9	14.2
MISO	35.7	35.6	41.7	26.6
NYISO	16.3	16.1	21.2	17.3
PJM	24.2	26.6	31.9	21.3
SPP	25.2	25.1	24.8	20.4
All	21.8	22.3	26.8	20.6

Table 7: Percentage of Year Covered by the Price Range from each Price Selection Methodology

This coverage analysis can also be done with historical generation data. For instance, it is possible to take a price from a methodology and find the generation amount in the DPT data that corresponds with the plus and minus 10% range. For example, the Implied price in the Spring Peak period is \$19.65/MWh, the -10% price is \$17.69, and the +10% price is \$21.62/MWh. The generation level corresponding to the price of \$17.69/MWh is 21,429 MW, and the generation level for the \$21.26/MWh price is 34,359 MW. During the Spring/Fall peak period in the base years, actual generation in SPP during the Spring/Fall Peak period fell in the range of 21,429 to 34,359 MW in 86% of the hours during the period. The very high share of hours generation output covered in the +/-10% price provides an indication that the Implied price is representative of market conditions, given the generation data in the DPT analysis.

We applied this exercise to all the DPT periods for all the RTOs and methodologies for the 2017 and 2018 years, and the summary is in Table 8. It shows the percentage of the years that are within the implied generation ranges calculated based upon each price methodology. In all cases, the generation range calculated from Implied and Model prices covers more of the years than the range established by the historical price-based other methodologies. On average, the Implied Model methodologies cover over twice the hours than do the ranges base the Average price methodology. In twenty-two of the sixty-three RTO/Periods tested, the Average price implied generation levels that never occurred during the DPT period! In thirty-seven of the sixty-three periods—over one-half—average price implied generation levels that occurred in less than 25% of the period. These results demonstrate conclusively that selecting prices consistent with the underlying DPT data are much more likely to produce generation levels consistent with actual generation levels, thereby the incentive to exercise market power as discussed with equation (3).

RTO	Implied	Model	Median	Average
CISO	58.6	27.2	22.5	23.6
ERCOT	97.8	97.8	56.4	36.6
ISONE	91.8	89.7	30.0	41.4
MISO	93.7	94.4	55.0	26.8
NYISO	88.2	74.6	24.0	38.4
PJM	77.1	74.3	46.1	27.7
SPP	84.0	84.0	47.3	42.7
Total	84.4	77.4	40.2	33.9

Table 8: Percentage of Year Covered by the Price Range from each Price Selection Methodology

These results show a significant disconnect between calculated generation levels based on average historical prices and DPT data on the one hand and actual historical generation levels on the other hand. How can such discrepancies exist? Although many factors likely drive the differences, we discuss two potential ones here. First, DPT analyses ignore daily unit commitment decisions that market operators make.[108] They essentially assume that generation units can be turned on or off costlessly depending upon small changes in price. On any given day in the real-world, many generation units are not committed to operation, which is to say the available fleet typically is less than the entire fleet that is available in a DPT analysis.[109] Given this, it is not surprising that real-world generation levels are less than those implied in DPT data given historical prices. Second, related to the first, DPT data include neither start-up nor no-load costs that generation units incur in actual operations.[110] This is especially problematic in contemporary electric power markets with natural gas prices often below the price of coal. Large coal-fired units that were designed to be base-load units with few starts per year are now intermediate units, or even peaking-type units in some cases.[111] It is very

108. John R. Morris, *The Good, the Bad, & the Ugly: A review of the Federal Energy Regulatory Commission's market-based rate (MBR) screens, from theory to application*, PUB. UTIL. FORTNIGHTLY (July 2005).

109. *Id.*

110. *Id.*

111. The coal-fired plants in Maryland ran only 17 days in 2019 and are expected to run only 14 days in 2020. *See* Samantha Hawkins, *Blue-Green Divide on Display as Workers Swarm Legislature to Oppose Coal*

costly to start a coal-fired unit, often running into the hundreds of thousands of dollars. The only costs included in the DPT are the average variable costs of a fully-loaded unit. So, there can be substantial costs missing in DPT analysis. Given the differences between real-world operations and DPT data, the results here are not surprising.

VI. OTHER CONSIDERATIONS

For the reasons discussed in section V, the implied, model, and median methodologies all perform better than the traditional average price methodology at replicating historical generation levels in a DPT analysis and at coverage of the year. In this section, we consider additional factors that one might consider when selecting representative price levels. These factors include trying to match to actual generations levels in traditional markets, matching generation levels and implied capacity factors for the applicant companies, the effects of FERC's mandate to use 105% of market prices for the DPT analysis and discuss price sensitivities, selecting representative load levels, and methodologies for selecting fuel costs.

A. Traditional markets and generation owner quantities

The analyses in section V can be performed for RTOs because they post substantial amounts of hourly data including generation levels, demand levels, electric energy flows into and out of the RTO, and prices. In contrast, as discussed in section II, good hourly price data may not be available in traditional markets outside of RTOs and proxies must be used. This leaves the problem of how to estimate representative market prices given a paucity of data. FERC has stated a preference for using EQR data in some fashion,[112] and has accepted lambda data or prices from adjacent RTOs when EQR data are sparse.[113] But even these proxies may not be available in all cases. For example, South Carolina Gas & Electric (SCG&E) is not directly adjacent to an RTO and has no reliable lambda data.[114]

One advantage of using either the implied price or model price methodologies is that they can be reliably used even when no historical price data are available. The prices are calculated to be consistent with the other underlying supply and demand data that FERC requires in the DPT analysis, as in Figure 2. These methodologies are also consistent with the *Bluegrass* decision where FERC accepted an alternative price methodology that better matched the implied capacity factors with the actual historical capacity factors.[115] Matching historical generation levels

Plant Shutdowns, MARYLAND MATTERS (Feb. 26, 2020), https://www.marylandmatters.org/2020/02/26/blue-green-divide-on-display-as-workers-swarm-legislature-to-oppose-coal-plant-shutdowns/.

112. *PJM Interconnection, L.L.C.*, 136 F.E.R.C. ¶ 61,245, at PP 119-129.

113. 139 F.E.R.C. ¶ 61,094, P 26; *Louisville Gas & Elec. Co. & Ky. Utilities Co*., 166 F.E.R.C. ¶ 61,206 (2019), *reh'g denied*, 168 F.E.R.C ¶ 61,152 (2019).

114. The lambda data for 2017 and 2018 filed at FERC are all zero. *See* F.E.R.C., OMB No. 1902-021, Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report (2017) (SCG&E's Q4, 2017 Report); F.E.R.C., OMB No. 1902-021, Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report (2018) (SCG&E's Q4, 2018 Report).

115. 139 F.E.R.C. ¶ 61,094, at P 26.

to the implied generation levels is another way to say that the implied price methodology is attempting to match the market capacity factor–*i.e.*, the amount of actual generation divided by the potential generation. As discussed in section V, the model price methodology also typically provides a close approximation to historical generation levels. Hourly net generation data is now available for most areas via EIA Form-930;[116] therefore, the implied price or modeling methodologies can be performed for most areas. When the hourly data are not available, the model methodology can be used.

Not only should FERC and practitioners examine the capacity of the total market, they should also examine the economic capacity of the applicants. Our discussion on price methodologies have been conducted on a market level, which is important because if the market level of generation is correct, then the amount of EC and AEC for that market would be correct. A market share calculation involves dividing a generation owner's capacity, the numerator, by the total market capacity, the denominator. Ensuring the correct capacity for the market ensures that the denominators are correct for market calculations. But just because the total capacity (denominator) is correct, does not mean that capacities for individual generation owners (the numerators) are correct. Because actual generation costs are not observable, any individual owner may have more or less economic generation capacity in a well-calibrated DPT study than its historical or expected future economic capacity. Therefore, it is also important to consider the economic capacity of the individual owners, especially the capacity of the applicants. In fact, it was an unrealistic implied generation level for an applicant that led FERC to accept a revised methodology in the *Bluegrass* matter, which involved LG&E/KU attempt to acquire a 495 MW peaking facility in Kentucky.[117] EQR data were sparse, covering only 11.5% of the year.[118] Using average EQR prices, the implied capacity factor for the assets to be acquired, the Bluegrass Facility was 28.7% whereas the facility actually ran in only 3.6% of hours and had only a 2.5% capacity factor.[119] Average EQR prices would clearly overstate the competitive significance of *Bluegrass*, so FERC allowed an alternative methodology.[120] Similarly, the opposite could occur so that one or both merger applicants would have less economic capacity than they actually would have or be expected to have in

116. EIA Form 930 provides hourly net generation, load, and interchange by balancing authority area. *See* U.S. ENERGY INFO. ADMIN., EIA-930 DATA USERS GUIDE AND KNOWN ISSUES (Jan. 11, 2018), https://www.eia.gov/realtime_grid/docs/userguide-knownissues.pdf.

117. 139 F.E.R.C. ¶ 61,094, at P 1.

118. *Id.*at P 14.

119. *Id.* at PP 15-16.

120. *Id.* at P 26.

the future.[121] Therefore, applicants and FERC should check that the implied capacity factors (*i.e.*, generation levels) in the DPT analysis reasonably match the historical levels of the applicants.[122]

Finally, when comparing implied capacity factors generation levels with historical data, the comparison should be based upon historical data and not the future test period. FERC requires the DPT analysis to be done for future periods and not a historical period.[123] Capacity factors can change going forward as demand, fuel prices, and generation capacities change. Other than through a study of likely future generation dispatch with fundamental model of supply and demand, expected capacity factors are not known. The historical data is preferable because we can observe what occurred. This can be compared to implied capacity factors based upon the historical data, including historical demand, fuel costs, and generation capacity. Once calibrated based on historical data, then the analysis can be brought into the future that includes all the expected changes to the fundamental determinants to market prices.

B. *Effects of Using Different Prices*

Another factor to consider in the selection of representative market prices is that the actual DPT analysis is not done with the representative market price selected, but 5% above the market price.[124] The exact reason for using a price that is 5% above the representative price is not clear. It likely comes from the DOJ and FTC Merger Guidelines in effect at the time.[125] The 1992 Guidelines defined markets "as a product or group of products and a geographic area in which it is produced or sold such that a hypothetical profit-maximizing firm, not subject to price regulation, that was the only present and future producer or seller of those products in that area likely would impose at least a 'small but significant and nontransitory' increase in price.'"[126] An earlier version of the Guidelines stated that when "attempting to determine objectively the effect of a 'small but significant and nontransitory' increase in price, the Department in most contexts will use a price increase of five percent lasting one year."[127] The 5% adder is also consistent

121. Although FERC staff did not state it in their deficiency letter in Duke/Progress, this would provide a logical basis for requiring an alternative analysis with either higher representative market prices or lower generation costs; *See* 139 F.E.R.C. ¶ 61,094, at PP 26-27.

122. Because most DPT periods cover very large aggregation of hours, it is not possible perfectly match implied generation levels with actual levels. Nevertheless, the implied levels and actual levels should be within a zone of reasonableness; *See* 136 F.E.R.C. ¶ 61,245.

123. Order No. 642, *supra* note 3, at 31,887 ("… merger analysis should be as forward-looking as practicable …"). DPT analyses for market-based rate applicants may be historical. *See* FED. ENERGY REGULATORY COMM'N, HORIZONTAL MARKER POWER, https://www.ferc.gov/horizontal-market-power.

124. Order No. 592, *supra* note 4, at 31,130-131; 18 CFR § 33.3(c)(4) ("For each destination market, the applicant must calculate the amount of relevant product a potential supplier could deliver to the destination market from owned or controlled capacity at a price, including applicable transmission prices, loss factors and ancillary services costs, that is no more than five (5) percent above the pre-transaction market clearing price in the destination market.").

125. 1992 Guidelines, *supra* note 70.

126. *Id*.

127. U.S. DEP'T OF JUSTICE, MERGER GUIDELINES (1984), https://www.justice.gov/archives/atr/1984-merger-guidelines [hereinafter 1984 Guidelines].

with the current Horizontal Merger Guidelines that state that current suppliers are included as suppliers to a market and "[f]irms that are not current producers in a relevant market, but that would very likely provide rapid supply responses with direct competitive impact in the event of a SSNIP [small but significant and non-transitory increase in price], without incurring significant sunk costs, are also considered market participants."[128]

Using a price that is 5% above the representative market price of course increases the amount of economic capacity from all suppliers. To see the effect on generation levels from increasing prices by 5%, we start with the implied prices. We use this for the benchmark because it most closely matches implied generation to historical generation levels. We then increase the price by 5% and calculate the relative absolute errors from the historical generation levels, which provides a percentage difference measure. The results are shown in Table 9, which shows the increase in generation increasing from 5.7% for PJM to 19.4% for ISONE. The overall average increase is 8.7%. In other words, using the 5% adder can increase generation and increase apparent market power. But this is calculated for EC. The increase for AEC can be substantially more than this amount because it is the leftovers after subtracting load, which is typically at least 90% of generation levels. An increase in generation capacity of 10% could easily double AEC in some markets.

RTO	Percentage Increase
CISO	7.2
ERCOT	12.9
ISONE	19.4
MISO	10.6
NYISO	13.3
PJM	5.7
SPP	7.1
All	8.7

Table 9: Percentage Increase in Generation Capacity from Using 5% Higher Prices

But because of the uncertainty of market prices, FERC has required applicants to do price sensitivities of +/-10%.[129] Because of the 5% adder, the actual price sensitivities are 5.5 percent below the market price and 15.5% above the market price.[130] To see the effect on generation levels from increasing prices by

128. U.S. DEP'T OF JUSTICE AND FEDERAL TRADE COMM'N, HORIZONTAL MERGER GUIDELINES (Aug. 19, 2010), https://www.justice.gov/atr/file/810276/download [hereinafter 2010 Guidelines].

129. *See* section II.

130. 5.5 = 100 - (100 + 5) x (1 - 10%); 15.5 = (100 + 5) x (1 + 10%).

15.5%, we start with the implied prices and average prices. We use these for the benchmarks to see the range potential range off effects from the positive price sensitivity. We then increase the price by 15.5% and calculate the relative absolute errors from the actual generation levels, which provides the percentage difference measure. The results are shown in Table 10. Starting with the implied price base, the increase in generation from the +10% price sensitivity ranges from 14.3% for PJM to 36.8% for ISONE, with an overall average increase is 21.3%. With using average prices as the base, the increase in generation above historical levels from the +10% price sensitivity ranges from 26.6% for PJM to 47.1% for MISO, with an overall average increase is 36.6%. These levels are simply too far from historical levels to provide meaningful evidence. For instance, in thirty-nine of the sixty-three DPT periods examined in this article, the +10% price sensitivity and average prices produced implied generation levels that were greater than the maximum generation in the RTO in any single hour of the DPT period. Even using the implied prices, which almost perfectly match average generation levels, the +10% price sensitivity produced implied generation levels that were greater than the maximum generation in the RTO in any single hour of the DPT period in twenty-two of the sixty-three DPT periods.

RTO	Implied Price Base	Average Price Base
CISO	18.8	30.8
ERCOT	36.0	45.2
ISONE	36.8	45.3
MISO	24.4	47.1
NYISO	22.1	36.4
PJM	14.3	26.6
SPP	19.0	41.7
All	21.3	36.9

Table 10: Percentage Increase in Generation Capacity from Using 15.5% Higher Prices

It is fair to see if results are sensitive to small variations in assumptions. But the standard +/10% of market prices (including the 5% adder) does not appear supportable. Some alternatives might include using smaller changes (*e.g.*, 5%) or doing the changes only for the applicants. For example, raising and lowering the applicants' generation costs by 5% would provide information whether small changes in costs would substantially change the results. For example, results might change substantially if several applicant generation units had costs that were not economic in a period by less than $1/MWh. Another alternative would be to first focus and generation output and utilization and then on prices. For example, implied prices can be calculated to match the average generation level in the period. One might examine implied prices that would occur at one standard deviation above or below the average generation levels. That would then provide a range of prices that are within at least some bounds of reasonableness.

C. Demand data

As discussed above, the obligation of each supplier to serve demand is another important component of the AEC calculation. Demand in the electric power industry, which is dominated by engineers, is called load and is measured in mega-Watts (MW) instantaneously or mega-Watthours (MWh) over time.[131] If median prices are better than average prices during a DPT period, then are median load levels better measures of representative load than average load levels?

Whether one uses median or average load levels during a DPT period is not likely to affect results significantly because the median and average load levels are similar. Table 11 shows the summary information for the percentage difference between average load levels and median load levels. In contrast to the differences for prices, the differences for load levels all fall in the range of -2.8% to 5.5%. Moreover, the average difference is only 1.3% and no more than 1.6% in any given RTO. Given these data, there is no reason *a priori* to believe that using either median or average load levels would substantially change the results of a DPT analysis.

RTO	Minimum	Average	Maximum
CISO	-0.6	1.4	5.1
ERCOT	-2.8	1.6	3.9
ISONE	-0.4	1.6	5.5
MISO	-1.0	1.0	4.1
NYISO	-0.3	1.0	4.7
PJM	-0.2	1.3	3.9
SPP	-1.6	1.0	3.0

Table 11: Summary of Percentage Differences between Average and Median Load Levels by RTO

D. Generation Costs

Generation costs make up the third major component of a DPT analysis. Above we have discussed how prices can be selected so that the prices, estimated supply curve, and demand can be consistent with a historical benchmark. If applicants were forced to use a price based upon historical data via FERC decision (*e.g.*, the median or average price), then applicants could adjust the supply curve to match the intersection of the historical price and historical demand. This could

131. *See* UNION OF CONCERNED SCIENTISTS, HOW THE ELECTRICITY GRID WORKS, https://www.ucsusa.org/resources/how-electricity-grid-works.

be accomplished by, for example, scaling the generation capacities or scaling the costs so that all three curves (price, demand, and supply) intersect at the same point. Different classes of generation units might be scaled differently to match historical capacity factors for that class of unit. For example, in *Bluegrass*,[132] the applicant could have raised the dispatch costs of the Bluegrass facility to match historical capacity factors at the average price level of the EQR data. But it seems unreliable to change thousands of data points in the generation data when just one point (the representative market price) can be adjusted to match the best knowledge available on generation. Therefore, we proceed assuming that applicants continue to seek the most representative supply curve given publicly available data and precedents set by FERC.

Many factors may vary generation costs within a DPT period. These factors be broken down into two main categories: (1) factors that vary capacities and (2) factors that vary costs given capacities.[133] Factors that affect capacity include unit outages, changes in thermal efficiencies based on weather, and the variation of in intermittent generation from hydroelectric, wind, and solar units. Only general information is known for many of these factors with no data available within a DPT period. Hourly data on intermittent generation are available. Factors that affect generation costs include unit heat rates, variable operations and maintenance expenses, and fuel costs. Most fuel costs do not vary appreciably within a DPT period. For example, coal contracts typically range from a quarter to three years. Natural gas prices, however, can change significantly within a DPT period as well as across a DPT period. We now turn to examining the two major sources of variation in supply with DPT periods.

Although generation output of intermittent generation such as hydroelectric, solar, and wind may vary substantially within a DPT period, the generation levels do not exhibit sufficient skewness in the distributions to substantially impact DPT analysis. For intermittent generation resources such as hydroelectric, solar, and wind, FERC requires applicants to use generation levels (capacity factors) averaged over five years.[134] Therefore, the question is whether averages are likely to substantially affect DPT results because averages mask skewness in generation levels within DPT periods.[135] Accordingly, we measured the skewness of total output from intermittent generation in the RTOs, and the summary results are on the left side of Table 12. Recalling that a skewness measure in the range of -0.5 to 0.5 is approximately symmetric, we can see that generation levels of intermittent generation resources typically are approximately symmetric. All but one of the minimum levels are in this range, and five of the seven averages are within the range. The two averages outside of the range are just above at 0.55 for CISO and

132. 139 F.E.R.C. ¶ 61,094.

133. ENERGY INFO. ADMIN., ELECTRICITY EXPLAINED (Mar. 19, 2020), https://www.eia.gov/energyexplained/electricity/electricity-in-the-us-generation-capacity-and-sales.php.

134. *See* Order No. 697, *supra* note 14, at P 344 ("With regard to energy-limited resources, such as hydroelectric and wind capacity, . . . we will allow such resources to provide an analysis based on historical capacity factors reflecting the use of a five-year average capacity factor.").

135. Hourly energy production for intermittent generation is not generally available on a unit or plant-specific basis. Historical generation and capacity factors can be calculated based on EIA Form 923 data, which contain data on energy generation by plant by month. *See* https://www.eia.gov/electricity/data/ eia923/.

0.54 for MISO. Some DPT periods, however, are highly skewed as indicated by the maximums being greater than 1. In these cases, we can expect the average level of generation being greater than the median or more typical level of generation, as shown on the right side of Table 12. Because intermittent generation has low marginal cost, using averages increases low-cost supplies and shifts out the supply curve relative to the median generation level. This can be one cause of estimated supply curves in DPT analyses having lower costs and implied prices than average price levels in the historical data.

	Skewness			Percentage Difference from Median		
RTO	Minimum	Average	Maximum	Minimum	Average	Maximum
CISO	-0.45	0.55	2.18	-5.55	2.9	14.94
ERCOT	-0.47	0.23	1.15	-4.26	3.84	13.05
ISONE	-0.37	0.43	1.7	-3.08	2.16	7.88
MISO	-0.01	0.54	1.42	2.07	8.73	21.31
NYISO	-0.28	0.13	0.81	-1.3	0.4	1.65
PJM	-0.62	0.36	1.43	-0.83	4.68	18.74
SPP	-0.35	0.12	0.79	-3.45	3.98	20.59

Table 12: Summary of Intermittent Generation Skewness by RTO

The second major source of variability of supply costs in DPT data is the price of natural gas, which can be skewed positive like electric power prices. To examine natural gas prices, we considered the two natural gas prices that are related to the largest quantity of gas-fired generation capacity for each of the seven RTOs.[136] We then match each hour in a DPT period to the two natural gas prices that for delivery in that hour. Based upon the hourly data, we then calculate skewness measures and the differences between the average prices and the median prices. The results are presented in Table 13, which shows that natural gas prices can be highly skewed positively. In five of the seven RTOs, on average, natural gas prices were highly skewed and every RTO had at least one period with highly skewed natural gas prices. And average natural gas prices averaged at least 10% more than median gas prices in each of the RTOs, and average gas prices could be double median gas prices in some RTOs (*e.g.*, NYISO and PJM). The difference between the average and median natural gas prices means that different processing methods for natural gas prices could have substantial effects on the estimated sup-

136. The Hitachi-ABB Velocity Suite database lists an ICE natural gas trading hub to each plant with a gas-fired unit. We then matched the ICE gas trading hubs to Gas Daily price points. We used the two price points that were matched to the greatest amount of generation capacity in each RTO.

ply curves in DPT analysis. This gives added impetus to verify that supply, demand, and representative market prices are consistent with each other in DPT market power studies.

	Skewness			Percentage Difference from Median		
RTO	Minimum	Average	Maximum	Minimum	Average	Maximum
CISO	-1.4	1.6	6.7	-2.2	14.7	68.7
ERCOT	-0.4	0.8	3.6	-0.5	13.5	74.1
ISONE	0.2	2.1	5.7	-1.6	30.1	95.8
MISO	-1.2	1.0	5.6	-1.4	10.8	80.8
NYISO	-0.2	2.6	10.5	-4.3	26.7	136.8
PJM	-0.4	2.1	7.3	-4.3	27.3	126.2
SPP	-1.2	0.5	2.7	-8.0	11.0	82.6

Table 13: Summary of Intermittent Generation Skewness by RTO

E. Effects on DPT Analyses

The data presented thus far indicates that different methodologies can produce different HHI results, but they do not demonstrate that different merger outcomes might be inferred from the different results. To demonstrate different inferences with different methodologies, in theory one could examine past filings and see how the results might be different with different methodologies for selecting representative market prices. Clearly different methodologies can produce different results. For example, in the Duke/Progress merger, applicants initially showed no screen violations during peak periods when accounting for the rate depancaking from the merger.[137] Using average prices based on the available EQR data, applicants showed one on-peak screen failure in Duke with the base prices and two with the +10% prices.[138] In *CPLE*, applicants showed two on-peak screen failures in the base prices and three in the +10% case.[139] This was sufficient for the Commission to require mitigation in approving the application.[140] Another method of selecting market prices could easily create a different result. Unfortu-

137. Duke Energy Corporation and Progress Energy, Inc., *Application for Authorization of Disposition of Jurisdictional Assets and Merger Under Sections 203(a)(1) and 203(a)(2) of the Federal Power Act*, FERC Docket No. EC11-60-000, Accession No. 20110404-5212, Apr. 4, 2011, at 23, 26, 27.

138. *Id.*

139. Duke Energy Corporation and Progress Energy, Inc., *Answer of Duke Energy Corporation and Progress Energy, Inc.*, FERC Docket No. EC11-60-000, Accession No. 20110829-0016, Aug. 23, 2011, Exhibit A.

140. 136 F.E.R.C. ¶ 61,245, at PP 1, 134 (2011).

nately, the workpapers necessary to determine how different methodologies of selecting representative market prices would affect the HHI results are typically filed on a confidential bases and not available to the general public. Therefore, an alternative method is necessary to determine how different methodologies might affect HHI results for individual transactions.

To develop a systematic methodology of evaluating how price sensitivities might affect HHI results and inferences of market power, we used DPT data from our other analyses in this article, such as the amount of additional generation from 5% higher prices shown in Table 9.[141] Using these data, we exhaust the list of transactions among generation owners that that might have HHI screen violations. Specifically, we do a 2ab calculation and use a threshold of 100.[142] This standard would be met whenever both firms have shares of 7.1% or more, or a firm with a 15% share acquires a firm with a share of 3.4% or more. In total, we have sixty-nine hypothetical transaction that we analyze. For each transaction, we calculate the HHI levels and changes for ten DPT periods for both EC and AEC, and we do the price sensitivities. In total, there are 16,560 cases of post-transaction HHIs and their changes.

Table 14 gives the number of HHI screening violations (or failures) by the methodology of selecting representative market prices, the measure of capacity (AEC or EC) and the price sensitivity case (-10%, base prices, and +10%). Several patterns emerge from the AEC results. First, and except for those that do DPT analyses, with the average prices, the number of AEC violations increases with the price level. This is also true for the median and model price methodologies. Interestingly, this pattern does not remain with the implied price methodology. The most screen violations occur with the base prices, with fewer violations in the +/110% cases for the methodologies not relying on historical prices. Second, it does not appear that using average prices is conservative in terms of producing AEC screen violations. It appears that the implied and model methodologies can produce more screen violations, although none of these differences are statistically significant in two-tailed tests at the standard 5% confidence level. As for the EC results, as expected there is less variance in the results compared to the AEC results. None of the differences are statistically significant, and there is no clear pattern in the results.

141. *See supra* Table 9.

142. The 2ab method comes from the fact that the change in the HHI from combining firm a with firm b is equal 2 times the share of firm a times the share of firm b, or mathematically 2ab. This can be a very quick screening methodology based on installed capacity. *See, e.g.*, Market Power Experts, *Comments to the Federal Energy Regulatory Commission Concerning Notice of Inquiry: Modifications to Commission Requirements for Review of Transactions under Section 203 of the Federal Power Act and Market-Based Rate Applications under Section 205 of the Federal Power Act*, FERC Docket No. RM16-21-000, Nov. 28, 2016, at 22-23.

Capacity Type	Price Case	Implied	Model	Median	Average
AEC	-10%	139	144	118	128
	Base	156	157	126	132
	+10%	148	160	135	136
EC	-10%	89	95	68	64
	Base	62	81	63	62
	+10%	63	76	71	73

Table 14: Number of DPT Screen Violations by Price Methodology, Capacity Measure, and Price Case

Table 14 gives information on which pricing methodology is most likely to produce screen failures, but it does not give information on whether the different methodologies identify the same transactions as being problematic. To address the issue of whether there is a relationship between the methodologies, we examine the number of screen violations across the methodologies. As before, we do this by the two capacity types. FERC requires mitigation only when the DPT analysis shows "systematic" screen failures,[143] but it has never explicitly stated what it considers systematic. For a definition of systematic screen failure, we use the criteria that a systematic screen failure exists if five or more of the twenty-one on-peak HHIs for either AEC or EC are above the screens.[144]

Table 15 shows the results for the relationship between the mergers likely to require mitigation and the methodology for the representative market price. As before, the results are divided between AEC and EC. To understand the data, consider the first row, for the implied methodology for AEC. It indicates that the implied methodology identified twenty of the sixty-nine transactions as requiring mitigation. Of those twenty transactions, all twenty were also identified by the model and median price methodologies, but only eighteen were identified by the average price methodology. In other words, the implied price methodology identified two transactions that the historical average method did not. Consider the next row, the model methodology identifies twenty-three transaction as needing mitigation. Of those twenty-three, the implied price and median price methodologies identify twenty and the average price methodology identifies eighteen of the twenty-three transactions as requiring mitigation. As for the standard average pricing methodology, it identifies eighteen transactions, and all eighteen would be

143. 136 F.E.R.C. ¶ 61,245, at P 134; *CP&L Holdings, Inc.*, 92 F.E.R.C. ¶ 61,023, at 61,054 (2000).

144. Three of the ten DPT periods are off-peak and seven are on-peak. With three price levels (-10%, base, and +10%), that gives 21 on-peak periods tested for each destination market in a transaction. We limit this screen to on-peak periods because FERC is traditionally more concerned with on-peak periods. *Bayou Cove*, 165 F.E.R.C. ¶ 61,226, at P 67 (2012) ("In determining whether an alternative geographic market is relevant for purposes of analyzing a transaction, the Commission examines 'whether there are frequently binding transmission constraints during historical seasonal peaks examined in the screens and at other competitively significant times that prevent competing supply from reaching customers within the [proposed alternative geographic market].'").

identified with the other methodologies. As expected from the results in Table 14, the EC results show fewer transactions requiring mitigation and less variance across the results. Nevertheless, the pattern remains that the different methodologies at the margin identify different transactions as being problematic. Although we note that none of these results differ by a statistically significant amount based on capacity type, they do not support the position that the average price methodology is more likely to find screen violations than the other methodologies.

Capacity Type	Methodology	Implied	Model	Median	Average
AEC	Implied	20	20	20	18
	Model	20	23	20	18
	Median	20	20	20	18
	Average	18	18	18	18
EC	Implied	9	9	8	8
	Model	9	10	8	8
	Median	8	8	10	9
	Average	8	8	9	9

Table 15: Transactions with Systematic Violations by Price Methodology and Capacity Measure

Another metric to consider is the amount of divested capacity that would be required to eliminate the screen failures. At times, crafting divestiture packages can be difficult because it is possible that divesting enough capacity in one time period ends up created screen failures in other time periods. In general, divesting the minimum of the two companies' capacities would eliminate the screen failure.[145] To find the amount that is necessary to divest to solve all screen failures, we take the maximum of the divestiture amounts across all the screen failures.[146] If screen violations are deemed systematic, then the divestiture amount is the amount to eliminate all the screen violations.

Table 16 shows the results on estimating divestiture amounts by representative price methodology. The first column gives the capacity type, AEC or EC. We give capacity types because some markets are driven more by EC considerations (*e.g.,* ISONE) and others are driven more by AEC (*e.g.*, SPP). The second column lists four different types of data calculated. The first row gives the number of transactions requiring divestiture out of a possible sixty-nine. The second row

145. At least any HHI changes are not driven by an increase in market share by the acquiring party.

146. In total, there could be up to 60 screen failures to consider (10 DPT periods, three price sensitivities, and two capacity types) for a transaction. In practice, the number of screen failures to consider are considerably less in most cases.

gives the minimum of the divestiture amount for those transaction requiring divestiture. The third row gives the average amount of divestitures necessary to mitigate the screen violations. The fourth row gives the maximum amount of divested capacity necessary for mitigation. The pattern repeats itself for the EC measure of capacity. For AEC, the divestiture numbers do not vary substantially across the pricing methodologies, but for EC, the implied and model methodologies on average produce lower divestiture amounts of up to 12%. To the extent that divestiture amounts can be viewed as a tax or penalty for mergers, the historical pricing methodologies appear to levy greater penalties without a corresponding increase of detecting anticompetitive mergers.

Capacity Type	Statistic	Implied	Model	Median	Average
AEC	Number of Transactions	20	23	20	18
	Minimum Divestiture (MW)	599	599	599	599
	Average Divestiture (MW)	3134	3300	3151	3025
	Maximum Divestiture (MW)	9234	9308	8623	8035
EC	Number of Transactions	9	10	10	9
	Minimum Divestiture (MW)	2669	2676	949	2656
	Average Divestiture (MW)	5540	5508	5806	6208
	Maximum Divestiture (MW)	8887	8737	9550	9550

Table 16: Transaction and Divestiture Amounts by Price Methodology

F. The Importance of Getting the DPT Inferences Correct

From the perspective of promoting the public interest, correctly assessing the competitive impacts of a merger is important because mergers can substantially reduce costs and improve consumer welfare. This can be seen through the increased efficiency gains from the changing ownership structure of power plants.[147] The most studied effects are with nuclear power plants.[148] An article by Davis and Wolfram found that divesting electric power plants increased nuclear plant operating performance by 10% and decreased wholesale power prices by $2.5 billion per year.[149] Although the article does not separately examine the effects of consolidation of ownership of deregulated (*i.e.*, divested) plants, it does show that larger fleets of regulated plants increase efficiency.[150] In PJM, Exelon operates

147. James B. Bushnell & Catherine Wolfram, *Ownership Change, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generation Plants*, CTR. FOR THE STUDY OF ENERGY MKTS., at 3-5 (Mar. 2005).

148. *Id.* at 4-5; Lucas W. Davis & Catherine Wolfram, *Deregulation, Consolidation, and Efficiency: Evidence from U.S. Nuclear Power*, 4 AM. ECON. J.: APPLIED ECON. 194, 207 (2012) [hereinafter Davis & Wolfram].

149. Davis & Wolfram, *supra* note 148, at 207-09.

150. *Id.* at 208-09.

about 50% of the nuclear capacity,[151] and its capacity factor from 2015 through 2019 was 96% compared to 92% for the other five owners.[152] This four-percentage point difference is about 0.8 GW of additional generation each hour. We estimate that each additional GW of nuclear generation reduces PJM system costs by about $0.49/MWh. The additional generation translates to about $300 million per year in lower energy prices in PJM. We also note that Calpine owns the largest fleet of gas-fired combined cycle plants in ERCOT, with about a 20% share of that generation technology.[153] Its average capacity factor is 68% compared to 47% for other generation owners with smaller fleets of gas-fired combined cycle units.[154] This also suggests that larger fleets can lead to efficiencies that increase output and lowers prices. More general work has also demonstrated that greater consolidation in the electric power industry is related to lower prices.[155] In summary, benefits can and do occur with larger generation fleets, especially when owners operate plants with similar technology.

Therefore, from the perspective of promoting the public interest, FERC should balance the procompetitive effects of mergers with the possible anticompetitive effects. In assessing these effects, two types of errors inevitably occur.[156] Type I errors are false positives, finding a market power problem when one does not exist. Type II errors are false negatives, not finding a market power problem that does exist.[157] Some have argued that FERC would seek to minimize false negatives and that FERC could safely ignore false positives because the cost of false negatives are large and the cost of false positives are non-existent.[158] But such a view totally discounts the efficiencies discussed above, and ignores the fact that any potential anticompetitive effects are likely to be short-lived. Entry in electric power markets is ongoing, and can now be accomplished rapidly.[159] The average amount of entry is more than enough to offset any reasonable anticompetitive withholding scenario within two years.[160] In addition, substantially more capacity sits in the generation queue, so the amount of entry can easily expand whenever economic conditions warrant it.[161] In summary, available data on possible

151. Hitachi-ABB, VELOCITY SUITE, *Unit Generation & Emissions – Annual*, 2015-2019.

152. *Id.*

153. *Id.*

154. *Id.*

155. *See, e.g.*, David A. Becher, J. Harold Mulherin, & Ralph A. Walking, *Sources of Gains in Corporate Mergers: Refined Tests from a Neglected Industry*, 47 J. OF FIN. & QUANTITATIVE ANALYSIS 57, 60, 86 (2012).

156. *See, e.g.,* Lawrence J. White, *Antitrust and Merger Policy: A Review and Critique*, 1 J. OF ECON. PERSP. 13, 14-16 (1987).

157. For a discussion on false positives and negatives on merger analysis, see J. Dutra & T. Sabarwal, *Antitrust analysis with upward pricing pressure and cost efficiencies*, PLOS ONE 15(1) e0227418 (2020).

158. *See, e.g.*, Mark J. Niefer, *Explaining the Divide Between DOJ and FERC on Electric Power Merger Policy*, 32 ENERGY L.J. 505, 529 (2012) ("Although there is a fairly substantial body of theoretical and empirical work suggesting that generators can, and sometimes do, exercise market power, there is little work concerning the net effect on consumers of electric power mergers – which can involve increased efficiencies benefiting consumers or increased market power harming consumers.").

159. John R. Morris, Jessica R.S. Dutra & Tristan Snow Cobb, *Should Market Power Still be a Concern in the U.S. Electric Power Industry?*, 33 ELEC. J. 106,725 (2020).

160. *Id.*

161. *Id.*

effects of mergers and acquisitions in the electric power industry suggest that a careful weighing of the relevant facts is important and that any assessment methodology should not be biased for or against mergers. In other words, the costs of false positives and false negatives should be considered in assessing whether mergers are in the public interest.

Despite this, the DPT methodology is conservative in that it is more likely to find market power. For example, on numerous occasions FERC has stated the DPT methodology is conservative.[162] Others have also observed that the methodology is conservative in the sense that FERC is more likely to require divestitures than is DOJ.[163] This is now in part because FERC maintained the old HHI screening thresholds whereas DOJ raised its HHI thresholds in 2010, so the minimum requirement to challenge a merger is a post-transaction HHI of 1,500 and an increase of at least 100.[164]

VII. CONCLUSION

As part of its section 203 merger review process, FERC requires applicants to calculate available economic capacity, which is very sensitive to "representative market prices."[165] Other than requiring applicants to supply two-years of price data, however, FERC does not specify how applicants are to determine representative market prices. Most applicants have used some variation of calculating average prices to determine the representative prices. Our theoretical and empirical investigation of Implied, Model, Median, and Average prices leads us to conclude that the traditional practice of using average prices is likely the least reliable method of selecting representative prices.

In order to be representative of market conditions, representative prices need to be able to reproduce generation levels and implicit capacity factors. Because of the inherent disconnect between historical prices and the estimated supply curves in DPT analyses, Implied prices from historical generation levels and DPT data, and Model prices based on DPT data alone, can be superior at replicating actual generation levels. Implied generation levels and capacity factors from Average prices are often greater than the historical capacity factors, which reinforces the idea that the Average price levels are not representative market prices. Moreover, the 5% adder used in DPT HHI calculations and price sensitivities can result

162. 138 F.E.R.C. ¶ 61,109, at PP 5, 35, 39, 56, 58; Order No. 592, *supra* note 4, at 68,600, 68,607. *See also Analysis of Horizontal Market Power under the Federal Power Act*, 138 F.E.R.C. ¶ 61,109, at PP 5, 35 (2016); Merger Policy Statement, *supra* note 4, at p. 30,119.

163. *Comment of the U.S. Department of Justice and the Federal Trade Commission*, FERC Docket No. RM16-21-000 (Nov. 28, 2016) [hereinafter F.E.R.C. Docket No. RM16-21-000]; *see also* Market Power Experts, *supra* note 142, at p. 4.

164. U.S. DEP'T OF JUST. & THE FED. TRADE COMM'N, HORIZONTAL MERGER GUIDELINES 21-22 (2010), https://www.justice.gov/atr/file/810276/download; FERC Docket No. RM16-21-000, *supra* note 163; 138 F.E.R.C. ¶ 61,109 at P 39; 2010 Guidelines, *supra* note 128, at section 5.3; Market Power Experts, *supra* note 142, at p. 5.; 138 F.E.R.C. ¶ 61,109, at P 39.

165. Order No. 642, *supra* note 3.

in Average prices producing implied DPT generation levels that rarely or never occur in actual market operations.[166]

We also show that using the +/- 10% price sensitivity cases provide too wide of a range of generation outputs, producing implied generation levels that never occur during DPT periods. Therefore, a smaller range to test for price sensitivity, such as +/- 5%, would be more appropriate.

Because merger analysis is forward looking, representative prices must be transformed from a selection based on historical data to represent expected prices in future market conditions. Therefore, we recommend that the representative price in the future test period for the DPT analysis be consistent with the other DPT data for that period. In that sense, a Model price would be a representative market price because it is the price that matches the supply and demand in the forward-looking DPT data. The study of potential transactions in this article demonstrates that this change would not reduce the likelihood of detecting anti-competitive mergers and, in fact, may more correctly identify truly anticompetitive mergers. This would be a logical next step in the evolution of the DPT analyses.

DATA APPENDIX

This exhibit describes data and assumptions used in the delivered price test study (study) carried out by us for this paper.

Transaction choices The study considers all transactions of generation owners in the U.S. ISOs (ERCOT, CAISO, ISONE, NYISO, PJM, MISO, and SPP) in which an HHI based on installed capacity would increase by 100 or more. The assigned ownership is based on Economists Incorporated's ownership data as of 2019. Base period data are from 2017 and 2018, and the forward period for the study is 2021. This criterion gives sixty-nine possible transactions to consider. If the data were not limited to HHI increases of 100 or more, there would be over 150,000 possible transactions, of which all but sixty-nine would have no likelihood of anticompetitive effects.

Periods The paper calculates market shares and concentration indexes for electric energy for ten representative periods during the year.

Geographic Regions The destination markets are each of the seven ISOs. The geographic market (supply area) includes the destination market plus each of the balancing authority areas in the US directly connected to the ISO.

Generation The study includes generating units located in the geographic region that are connected to the power grid. The study uses data for summer and winter capability at the unit level reported in the Velocity Suite Generation Unit Capacity database available from Hitachi-ABB PowerGrid. The study uses variable costs of generation that include fuel costs, sulfur dioxide and nitrogen oxide emissions costs, and variable operations and maintenance (VOM) costs.

Loads The report uses estimates of load obligations from information available from public sources such as EIA Form 861. The calculation is performed in

166. The 5% adder accounts for easy entry (i.e., responses of other generators if a seller attempts to exercise market power). It is appropriate only if it is applied to a proper base price. As shown above, Average Prices tend to be higher than representative market prices; therefore, adding another 5% compounds the errors from using Average Prices.

five steps. First, the hours in each period are identified based on time and load level for the destinations. Second, load "shapes" are calculated so that the annual load level in EIA 861 data can be translated into a load amount during each of the ten periods. Third, the annual loads served by state and balancing area are then merged with the shapes to give the expected load level served in each period. Fourth, when actual hourly load data for an entity are available (e.g., from Form 714), we use the actual hourly load data. Finally, an "obligation" amount is applied to each of the calculated load levels. These obligation amounts are 100% for municipal cooperative, and regulated IOU systems without retail competition, 90% for IOU systems with limited retail competition (e.g., Detroit Edison), 60% for IOUs with competitive retail access, and 30% for retail power marketers.

Transmission The paper incorporates a contract path transmission network for modeling purposes. Transmission pricing between balancing authority areas in each Region is represented by a traditional contract path transmission network in which the direct physical connections between balancing authority areas are also the individually priced links from which contract paths are constructed. Transfer capabilities are based on OASIS postings. Transmission rates and losses are based on tariff filings and OASIS postings.

Market Prices The calculation of market prices during base periods is discussed in the article. The base period prices were moved to the forward period based on a simulation consistent with the data. For example, if the base period average price during a DPT period were \$20.00/MWh and the change from the base period to the forward period is -\$0.50/MWh, then the price for the average methodology in the forward period would be \$19.50/MWh.


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UTILITY MERGERS AND THE MODERN (AND FUTURE) POWER GRID

By Scott Hempling
*Reviewed by Joshua C. Macey**

Abstract: Scott Hempling's *Regulating Mergers and Acquisitions of U.S. Electric Utilities* provides a comprehensive history of electric utility mergers in the United States since the 1980s. Hempling documents the dramatic consolidation the industry has seen in the past fifty years, and he convincingly argues that electric utility mergers present unique problems for regulators. This Review considers how utility acquisitions (a) allow holding companies to leverage the utilities' creditworthiness to cross-subsidize non-utility affiliates, and (b) exacerbate informational asymmetries between regulators and utilities. It argues that utility mergers generate negative spillovers outside of the utility's service territory that have potentially significant environmental consequences, and argues that FERC and state energy regulators have been overly reluctant to respond to these challenges, even compared to regulators that oversee other heavily regulated industries.

I. INTRODUCTION

Scott Hempling's *Regulating Mergers and Acquisitions of U.S. Electric Utilities* traces the wave of mergers and acquisitions that transformed the electric power industry at the end of the twentieth and beginning of the twenty-first century.[1] Hempling's book is the latest in a long line of scholarship, much written by Hempling himself, exploring how market power remains a pervasive problem in restructured electricity markets.[2] As Hempling documents, since the 1980s, "a stream of mergers and acquisitions has cut the number of local, independent electric retail utilities in the U.S. by more than half."[3]

Regulating Mergers and Acquisitions offers a powerful and persuasive argument that utility mergers raise unique challenges for energy regulators. Elec-

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1. *See* SCOTT HEMPLING, REGULATING MERGERS AND ACQUISITIONS OF U.S. ELECTRIC UTILITIES: INDUSTRY CONCENTRATION AND CORPORATE COMPLICATION xxiii (2020) [hereinafter REGULATING MERGERS AND ACQUISITIONS].

2. *See* Scott Hempling, *Inconsistent with the Public Interest: FERC's Three Decades of Deference to Electricity Consolidation*, 30 ENERGY L.J. 233 (2018); Ari Peskoe, *Is the Transmission Syndicate Forever?*, 42 ENERGY L.J. 1 (2021) (critiquing investor-owned utilities control over transmission planning); Joshua C. Macey & Robert Ward, *MOPR Madness*, 42 ENERGY L.J. 67 (2021) (critiquing buyer-side market power mitigation rules); Joshua C. Macey & Jackson Salovaara, *Rate Regulation Redux*, 168 U. PA. L. REV. 1181, 1184 (2020) (arguing that resource adequacy reforms revise principles of public utility regulation); David Spence & Robert Prentice, *The Transformation of American Energy Markets and the Problem of Market Power*, 53 B.C. LAW REVIEW 131, 131-32 (2012).

3. *See* HEMPLING, REGULATING MERGERS AND ACQUISITIONS, *supra* note 1, at xxiii.

tric utilities, at least those Hempling analyzes,[4] enjoy a government-granted monopoly franchise. In ordinary markets (by which I mean markets that are not dominated by rate regulated monopolists), competition disciplines firm behavior. Acquirers pursue targets because they believe the merger or acquisition will generate scale economies, or because they believe that the acquirer can improve the target's performance. Either way, mergers in ordinary markets at least theoretically benefit consumers as increased efficiencies allow firms to provide less expensive or superior goods.[5] Utilities that possess a monopoly franchise, by contrast, are controlled by state and federal energy regulators but not by market forces.

To a casual observer, it might not be clear why utility mergers pose a problem for the electricity industry. Utilities already enjoy monopoly franchises. Why, then, should we be concerned when two monopolists join forces? One argument, commonly put forth by utilities themselves, is that utility mergers have helped the electric industry realize economies of scale and scope.[6] Alternatively, a naïve observer of energy markets may feel that utility mergers have a neutral effect on energy markets. Mergers and acquisitions do not increase the acquirer's market power in the utility market. Before the merger, the acquirer and the target companies each enjoyed a monopoly. Since both acquirer and target returns are closely supervised by a regulatory body, one could plausibly conclude that utility mergers are neither harmful nor beneficial, since public utility commissions continue to scrutinize the price and services utilities offer after two utilities merge.[7]

But that is not the story Hempling tells. On his account, utility mergers support the interests of utility shareholders to the detriment of their captive ratepayers. In the absence of competition, acquirers do not pursue companies that will improve their own operations. Instead, they seek to take advantage of state government decisions granting distribution companies a monopoly over a physical distribution territory. The recurring theme is that utility acquisitions reflect an attempt to exploit what Hempling calls the "unearned advantage" that utilities obtain as result of their exclusive franchise.[8]

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4. The Federal Power Act defines "public utility" broadly to mean any energy company subject to the jurisdiction of the Federal Energy Regulatory Commission. *See* 16 U.S.C. § 824(e). Hempling is analyzing utilities that enjoy a monopoly privilege. In this Review, I use the word utilities to refer to these rate regulated utilities—not as utility as defined in the FPA.

5. This assumes, of course, that the acquisition is not anticompetitive. *See, e.g.*, Colleen Cunningham, Florian Ederer & Song Ma, *Killer Acquisitions*, J. POL. ECON. 3, 19 (2020) (analyzing the practice of "acquir[ing] innovative targets solely to discontinue the target's innovative projects and preempt future competition.").

6. *See* HEMPLING, REGULATING MERGERS AND ACQUISITIONS, *supra* note 1, at 87, 195 (describing these potential benefits).

7. *See* David Spence, *Can Law Manage Competitive Energy Markets*, 93 CORNELL L. REV. 765, 769 (2008) ("Traditional regulation guaranteed that licensed monopoly energy service providers would be able to charge administratively established rates that allowed the companies a 'fair' return on their prudently made investments. In return, these 'public utilities' agreed to meet a variety of service obligations to the general public, including the obligation to serve all eligible customers and provide a reliable source of supply. State public service commissions regulated retail rates, and the Federal Energy Regulatory Commission (FERC) regulated wholesale rates.").

8. *See* HEMPLING, REGULATING MERGERS AND ACQUISITIONS, *supra* note 1, at 154.

Regulating Mergers and Acquisitions is a terrific book, but its importance is not in showing that electric utility mergers have harmed electricity markets. We already know that, in no small part because of Hempling's prior work. Its contribution lies in its analysis of *why* utility mergers are harmful. Hempling makes a convincing case that acquirers leverage a utility's unearned advantage to subsidize non-utility affiliates. Doing so exposes utility customers to the affiliate's risks and gives the affiliate an advantage that was never intended to be used in the non-affiliate's market.

This Review focuses on two concerns raised by *Regulating Mergers and Acquisitions of U.S. Electric Utilities*[9]: (1) that utility mergers allow corporate affiliates to obtain advantages despite the fact that there is no reason to protect these affiliates from competition, and (2) that utility mergers exacerbate informational asymmetries and, in doing so, make it difficult for regulators to adequately supervise the operations of the firms they are charged with regulating.

Hempling is correct that acquisitions allow firms to use utility revenues to provide credit enhancements to non-utility affiliates. These credit enhancements are best understood as subsidies that flow from ratepayers to affiliates that do not enjoy monopoly franchises. That, in turn, allows non-utility affiliates to secure more favorable financing than their competitors. Hempling is also correct that utility mergers make it difficult for energy regulators, who face jurisdictional constraints and have access to limited resources, to manage the firms they are charged with regulating.

A recurring theme in *Regulating Mergers and Acquisitions* is that the behemoths that now dominate the retail electricity markets have managed to leverage their utility businesses to give themselves substantial advantages in related markets. These spillovers not only harm utility customers, but they also give utilities' affiliates an advantage over their competitors and hamper implementation of environmental policies.

This Review considers precisely how electric utility mergers differ from mergers in other industries in which the government has granted some market participants a valuable franchise. As described below, electric utilities are not entirely unique. Railroads, financial institutions, and telecommunications have long been afforded special government protections, and they have sought to use these protections to support their affiliates.[10]

Still, Hempling is right that the approach FERC and state public utility commissions have adopted to regulate utility mergers and acquisitions is remarkable even compared to these other highly regulated industries.[11] Regulators in these industries have long been aware that firms that enjoy these protections might be able to leverage them to their advantage in related industries.[12] For example, bank regulators have responded to some of the problems Hempling ana-

9. These are far from the only distortions Hempling analyzes.

10. *See* Lina M. Khan, *The Separation of Platforms and Commerce*, 119 COLUM. L. REV. 973, 1037-51 (2019).

11. *See* infra Part III.

12. The electric industry had similar requirements until Congress repealed the Public Utility Holding Company Act of 1935 (PUHCA). See HEMPLING, REGULATING MERGERS AND ACQUISITIONS, supra note 1, at 67-68.

lyzes by strictly limiting banks' ability to lend to affiliates and insisted that loans be negotiated at arm's length.[13] Other industries have adopted similarly strict merger policies to prevent regulated businesses from leveraging their franchise to support non-regulated affiliates.

Finally, it is worth emphasizing that there is some hope for reform. Section 203 of the Federal Power Act (FPA) requires that FERC approve mergers only if the merger will "not result in cross-subsidization of a non-utility associate company."[14] Hempling's analytic contribution about the harms caused by utility mergers thus suggests that FERC's merger policy is inconsistent with its statutory mandate.[15]

Part II of this Review describes the regulatory landscape that governs utility mergers. Part III focuses on Hempling's claim that utility acquisitions allow acquirers to cross-subsidize non-utility businesses. These cross-subsidies impede innovation, undermine decarbonization policies, and thwart efforts aimed at opening electricity markets up to competition. Part IV considers how utility consolidation exacerbates informational advantages utilities enjoy compared to their regulators. These informational asymmetries further undermine climate policy and efforts to reduce barriers to entry for independent power producers. Part V argues that Hempling's proposal, in which utility regulators adopt a proactive approach and approve utility mergers and acquisitions on the condition that the utility meaningful operational improvements, would also mitigate some (though not all) of these harms.

II. Regulating Utility Mergers and Acquisitions

The United States used to have a federal policy that governed electric utility mergers. Under the Public Utility Holding Company Act of 1935 (PUHCA), the Securities and Exchange Commission (SEC) could approve utility mergers and acquisitions only if the transaction created economic benefits and involved geographically contiguous utilities.[16] PUHCA ensured that electric utilities remained relatively small, limited the amount of debt utilities could take on, and prevented utilities from expanding into riskier businesses.[17]

Today, FERC and states generally both have jurisdiction over utility mergers. After Congress repealed PUHCA's restrictions on utility mergers as part of the Energy Policy Act of 2005,[18] it made FERC responsible for regulating mergers and acquisitions that involve two or more electric utilities.[19] And, Congress

13. *See* infra Part III.

14. Federal Power Act of 1935 § 203, 16 U.S.C. § 824b(a). If the merger does result in a cross-subsidy, FERC can approve of it if it provides evidence that the merger is nevertheless "in the public interest." *Id*.

15. Hempling has previously made this argument in these pages. *See* Hempling, *Inconsistent with the Public Interest*, *supra* note 2, at 239.

16. Public Utility Holding Company Act of 1935, 15 U.S.C. § 79 *et seq*.

17. *See* Hempling, Regulating Mergers and Acquisitions, *supra* note 1, at 67-68.

18. Interestingly, the pattern of utility mergers Hempling describes began in the 1980s, more than twenty years before PUHCA's repeal.

19. Federal Power Act of 1935 § 203, 16 U.S.C. § 824b.

gave FERC wide discretion to determine the best policy for regulating utility mergers.[20]

Section 203 of the FPA is the statutory basis of FERC's authority to regulate utility mergers.[21] Section 203(a)(4) instructs the Commission to approve proposed mergers and acquisitions "if it finds that the proposed transaction will be consistent with the public interest."[22] Notably, FERC must find that the merger will "not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the benefit of an associate company unless the Commission determines that the cross-subsidization, pledge or encumbrance will be consistent with the public interest."[23]

As Hempling observes, FERC has never adequately defined this "public interest" standard.[24] However, in 1996, the Commission issued Order No. 592, which outlines the Commission's merger review policy.[25] Order No. 592 establishes a five-step process that the Commission uses to analyze utility mergers.[26] FERC considers, among other things, if the transaction "would significantly increase concentration," if the merger "raises concern about potential adverse competitive effects," and if the merger will lead to "efficiency gains that reasonably cannot be achieved by other means."[27] According to FERC, this screen "identif[ies] proposed mergers that clearly will not harm competition."[28] Though FERC has repeatedly updated its merger review policy,[29] it has continued to permit mergers and acquisitions that cause no harm, which means simply that the identifiable costs do not exceed the benefits.[30]

And this standard has proven to be highly accommodating of mergers and acquisitions and, according to Hempling, fails on its own terms.[31] When FERC

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20. FERC must make sure that the merger is in the "public interest," though it did not define this standard, and that the utility not be used to cross-subsidize non-utility affiliates. *See id.*

21. Federal Power Act of 1935 § 203, 16 U.S.C. § 824b(a).

22. *Id.* § 824b(a)(4).

23. *Id.*

24. *See* HEMPLING, REGULATING MERGERS AND ACQUISITIONS, supra note 1, at 65-72, 102, 109.

25. *See* Order No. 592, Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, 77 F.E.R.C. 61,263 (Dec. 18, 1996). FERC's policy is based on the Department of Justice and Federal Trade Commission's 1992 Horizontal Merger Guidelines. *See* 138 F.E.R.C. ¶ 61,109, at 2 (Feb. 16, 2012) (citing U.S. Dept. of Justice & Federal Trade Commission, "Horizontal Merger Guidelines" (1992)).

26. *See* Order No. 592, 77 F.E.R.C. at 3.

27. *Id.* at 3-4.

28. *Id.* at 4.

29. Order No. 642, Revised Filing Requirements under Part 33 of the Commission's Regulations, 65 Fed. Reg. 70,983 (Nov. 28, 2000) (revising data requirements); Order No. 667, Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005, 113 F.E.R.C. ¶ 61,248, at 4, 6 (2005) (stating that "PUHCA 2005 [the merger requirements Congress passed in 2005] is primarily a 'books and records access' statute and rejecting requests to "reimpose particular requirements in PUHCA 1935 that Congress chose not to include in PUHCA 2005."); Order No. 669, Transactions Subject to FPA Section 203, at 6 (2005) (explaining the evidentiary basis the Commission would use to establish cross subsidization from a utility to a non-utility affiliate).

30. *See* HEMPLING, REGULATING MERGERS AND ACQUISITIONS, *supra* note 1, at 273; *Entergy & Gulf States, Inc.*, 121 F.E.R.C. ¶ 61,182 at P 71 (2007) (stating that FERC imposes conditions on utility mergers and acquisitions "only when needed to address specific, transaction-related harm").

31. *See* HEMPLING, REGULATING MERGERS AND ACQUISITIONS, supra note 1, at 72-73.

reviews mergers, it provides substantial deference to utilities' claims about the economic benefits of the proposed merger and only requires that the utility show that the proposed merger or acquisition does not cause any harm. Hempling objects to FERC's merger review process—rightly, in my opinion—both because it fails to identify many of the harms caused by utility mergers, and because the costs of error seem to be more significant when the Commission is overly accommodating of mergers than when it blocks value-adding transactions. Given the broad discretion the FPA affords the Commission, this seems to be largely a problem of FERC's making.

States, too, oversee utility mergers and acquisitions. Typically, state public utility commissions have jurisdiction only when the target of the merger or acquisition is subject to its jurisdiction.[32] FPA Section 203 does not preempt state merger laws.[33] Thus, a state can block a utility merger even if FERC has approved it.

While there are considerable differences among state merger policies,[34] states have also failed to pay sufficient attention to the effects of utility mergers. Like FERC, states routinely apply the no-harm standard when approving utility mergers.[35] As a result, many utility mergers are approved with only minimal concessions. Sometimes the utility will offer a customer credit, perhaps for $100, to entice a regulator to approve a merger. Or the utility might commit to investing in new office space in a community. Or it might agree to pursue other policies such as energy efficiency programs.[36]

But these concessions fail to mitigate the harms Hempling analyzes. While a comprehensive analysis of the ills caused by utility mergers is beyond the scope of this Review,[37] it is worth pointing out that the no-harm standard fails even on its own terms: FERC refuses to consider many tangible and quantifiable harms. It is perhaps axiomatic that a no-harm standard should establish that the proposed transaction does not in fact cause harm.

But this is not what FERC does. Hempling shows that, among other things, FERC focuses exclusively on wholesale competition and thus ignores anticompetitive effects utility mergers have on retail competition, reviews mergers in isolation and therefore ignores their cumulative effects and fails to consider whether there is sufficient regulatory capacity to supervise the consolidated company.[38]

32. *See id*. at 459.

33. *See id.* at 463.

34. *See id*. at 85-102 (describing state and FERC merger reviews).

35. *See id*. at 65-73 (discussing the no-harm standard).

36. HEMPLING, REGULATING MERGERS AND ACQUISITIONS, *supra* note 1, at 78-79; 85-102.

37. Readers are advised to go directly to the source and read Hempling's book.

38. *See id*. at 192-93 (describing an exception to this rule in which California denied a Southern California Edison-San Diego Gas & Electric merger application in part because it would make it more difficult for regulators to supervise the utilities).

III. CROSS-SUBSIDIZING NON-UTILITY AFFILIATES

A distinctive feature of utility mergers and acquisitions is that companies pay to control a utility's monopoly franchise.[39] Hempling calls this their "unearned advantage."[40]

The utility's exclusive franchise confers substantial benefits on the consolidated firm. For example, a holding company may try to "hide" one of its non-subsidiary's costs in the utility's rate base. Non-utility affiliates often participate in competitive generation markets. If the affiliate manages to recover some of the costs of generating electricity by including them in the utility's rate base, it will be able to sell electricity at a lower price, potentially pushing some of its competitors out of the market. This is a form of predatory pricing. But unlike traditional forms of predatory pricing, the firm does not incur a loss when it is predating, because it is able to use its utility to recover the losses incurred by the non-utility affiliate.

But perhaps the most insidious advantage that acquirers enjoy is that the utility's monopoly franchise can be used to create financing advantages for non-utility affiliates. Utilities have captive customer bases. Their rates are controlled by state utility commissions. Utility franchises therefore generally allow utilities to enjoy stable earnings. Historically, the primary risk pure-play utilities faced arose when they invested in new technologies that proved more expensive than expected.[41]

When a utility's holding company also owns non-utility subsidiaries, the holding company can use the utility's earnings to support non-utility affiliates. As Hempling explains, a holding company can use revenues generated from utilities "(a) . . . to finance the operations of non-utility affiliates, (b) lend money directly to those affiliates, or (c) pledge the utility's assets as collateral for third-party loans to affiliates."[42]

These are cross-subsidies. The holding company uses the utility's assets as a credit enhancement to support non-utility affiliates. Doing so renders the utility less financially secure. When a utility guarantees non-utility affiliates' debt, creditors of non-utility affiliates can pursue the utility's assets directly. Such guarantees benefit non-utility affiliates by lowering their financing costs. In doing so, however, they make the utility less financially secure. A utility's cost of debt will increase as it becomes exposed to its affiliates' business risks. As a result, its captive customers' costs will increase as the utility has to pay more to finance its own operations.[43] In other words, market consolidation has exposed electric utilities to some of the risks incurred by non-utility affiliates.

It is worth noting that these credit enhancements are unusual even in highly regulated industries. For example, the Federal Reserve strictly limits the amount

39. This is not to say acquirers are motivated exclusively, or even primarily, by this unearned advantage. An acquisition may create economies of scale, or a utility may also be trying to exercise more prosaic forms of anticompetitive conduct such as refusing to deal with competitors.

40. *See* HEMPLING, REGULATING MERGERS AND ACQUISITIONS, supra note 1, at 154.

41. *See id*. at 283-84.

42. *Id*. at 287.

43. Hempling discusses these arrangements in detail in Chapter 7. *See id*. at 283-89.

that insured depository institutions are allowed to loan to their affiliates.[44] The Fed also requires that inter-affiliate loans be negotiated on an arms-length basis.[45] Insured depository institutions are therefore prohibited from making favorable loans to their affiliates. These limitations make it difficult for banks to lend to their non-FDIC-insured affiliates and thus ensure that the protection afforded by FDIC insurance cannot be used to support high-risk (and less closely regulated) activities. Similar arrangements have historically been used in other regulated industries.[46] In fact, until PUHCA's repeal, electric utilities were unable to enter into complex financing arrangements whereby a non-utility affiliate used a utility's profits to secure more favorable financing.

FERC, too, ostensibly scrutinizes transactions between utilities and non-utility affiliates,[47] but in reality the Commission has proven highly deferential to utility requests to support the financing needs of their non-utility affiliates.[48] According to a Jones Day memorandum, "[m]any applicants now request a waiver from the competitive bidding obligations that otherwise would apply, which is typically granted."[49]

As a result of this lenient treatment, utility mergers have likely allowed carbon-intensive generation facilities to gain an advantage in restructured energy markets and introduced distortions in markets that are ostensibly competitive. Consider, for example, American Electric Power (AEP), which is the fifth largest electric utility in the United States.[50] According to AEP's website, coal accounts for approximately 45% of AEP's generating capacity, with natural gas accounting for an additional 28%.[51]

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44. See Fed. Res. Act § 23A (limiting the amount banks can lend to covered affiliates); *See also* Saule T. Oumarova, *From Gramm-Leach Bliley to Dodd-Frank: The Unfulfilled Promise of Section 23A of the Federal Reserve Act*, 89 N.C.L. REV., 1683, 1692-1701 (2011) (describing the scope of these restrictions).

45. Fed. Res. Act § 23B (requiring transactions between banks and affiliates be negotiated at arm's length).

46. *See* Lina M. Khan, *The Separation of Platforms and Commerce*, 119 COLUM. L. REV. 973, 1037-51.

47. *See* 8 C.F.R. § 34.2(a).

48. *See, e.g.*, *AEP Tex. Cent. Co.,* 126 F.E.R.C. ¶ 62,156, at P 1 (2009) (granting a waiver from the Commission's competitive bidding requirements and authorizing AEP Texas Central to issue more than $300 million in long-term debt securities, including $200 million that can be issued to its corporate parent). FERC has established conditions for utilities that extend debt to non-utility affiliates. These are known as the Westar conditions. *Westar Energy, Inc*., 102 F.E.R.C. ¶ 61,186 at PP 20-21 (2003), *order on reh'g*, 104 F.E.R.C. ¶61,018 (2003) ("First, public utilities seeking authorization to issue debt backed by a utility asset must use the proceeds of the debt for utility purposes. Second, if any utility assets that secure debt issuances are divested or 'spun off,' the debt must follow the asset and also be divested or 'spun off.' Third, if any of the proceeds from unsecured debt are used for non-utility purposes, the debt must follow the non-utility assets. Specifically, if the non-utility assets are divested or 'spun off,' then a proportionate share of the debt must follow the divested or 'spun off' non-utility asset. Finally, if utility assets financed by unsecured debt are divested or 'spun off' to another entity, then a proportionate share of the debt must also be divested or 'spun off.'").

49. JONES DAY, FEDERAL ENERGY REGULATORY COMMISSION REGULATION OF SECURITIES (Nov. 2009), https://www.jonesday.com/en/insights/2009/11/federal-energy-regulatory-commission-regulation-of-securities.

50. *See* STATISTA, LARGEST ELECTRIC UTILITIES BASED ON MARKET VALUE IN THE UNITED STATES AS OF APRIL 2020, https://www.statista.com/statistics/237773/the-largest-electric-utilities-in-the-us-based-on-market-value/.

51. *See* AEP, SUPPLYING ENERGY NATIONWIDE, https://www.aep.com/about/businesses/generation#:~:text=Today%2C%20coal%2Dfueled%20power%20plants,energy%20efficiency%20(3%20percent).

Many of these generation assets are held by AEP Generation Resources, a non-utility affiliate.[52] AEP's SEC filings list hundreds of millions in transfers from utilities to other affiliates of AEP.[53] In 2016, for example, AEP was allowed to borrow nearly $1.2 billion from its utility money pool and on average borrowed approximately $579 million.[54] AEP does have to keep its utility debt obligations separate from its nonutility debt obligations,[55] but the company's filings suggest that the creditworthiness of AEP's utility subsidiaries is closely linked to the creditworthiness of its non-utility subsidiaries, with the same short-term credit program being used to meet the AEP's utility and non-utility borrowing needs.[56]

The result is that holding companies are able to use government-granted monopoly franchises to enhance the creditworthiness of their non-utility affiliates, and they are able to do so to a greater extent than similarly-situated industries. Hempling returns again and again to the idea of utility exceptionalism. Here, it seems that the relaxed regulatory standard that applies to electric utilities is exceptional even compared to other industries in which one firm could use a government benefit to cross-subsidize its affiliates.

And credit enhancements provided by electric utilities to non-utility affiliates undermine the financial strength of the utility. This increases the cost of debt, which forces utility customers to pay more for electricity. At the same time, these credit enhancements give the holding company's other subsidiaries an advantage in their markets. To the extent that these subsidiaries hold mostly carbon-intensive generation facilities, the result is that captive ratepayers are subsidizing fossil generators with a large carbon footprint. This is the case regardless of whether the utility's regulator has adopted decarbonization policies.

IV. Information Asymmetries

Utility mergers and acquisitions also increase informational asymmetries that make it difficult for energy regulators to supervise utility rates and services. One reason this occurs is epistemic. Public utility commissions with limited resources struggle to monitor the many business lines owned by a large holding company that may implicate the service the utility provides to a community. This challenge is compounded by the fact that the FPA distributes jurisdiction between state and federal regulators such that no sovereign has authority to supervise all facets of a large holding company's energy company's operations.[57]

More surprising, perhaps, is that utility mergers undermine what little competition rate regulated utilities face. This is surprising because rate regulated

52. *See id.*; AEP, OPERATIONAL STRUCTURE, https://www.aep.com/Assets/docs/investors/fixedincome/AEPOperationalStructure.pdf.

53. *See* AEP 2016 Annual Report, Form 10-K, 79 (listing $25.6 million in transfers in 2015 and $24.1 in 2016); 92 (listing $11.7 million in transfers in 2015 and $12.5 million in 206); 106 (listing a $331 million transfer in 2015 and $24 million in 2016), https://www.sec.gov/Archives/edgar/data/4904/000000490417000019/aep10kfrex1320164q.htm#sE1B8A9D425C6EC14FC5F51A6D5E00DF8.

54. *See id*. at 274.

55. *See id*. at 39.

56. *See id*. at 272.

57. *See* Matthew R. Christiansen and Joshua C. Macey, *Long Live the Federal Power Act's Bright Line*, 134 HARV. L. REV. 1360, 1364-66 (2021) (describing the FPA's allocation of jurisdiction).

utilities possess government-granted monopolies and therefore by definition do not face competition. But as Hempling points out, while utilities do not compete with each other directly, regulators consider the rates set by other public utility commissions when setting utility rates. When utilities apply for rate increases, public utility commissions often consider the rates and services of similarly situated utilities. In other words, fragmented utility markets improve *comparability*. An electricity sector with many different utilities provides substantial data to regulators who want to compare utilities to each other. That, in turn, can be used to encourage utilities to provide more efficient service. Thus, while a utility may not lose customers if it provides inadequate rates and services, regulators may become more skeptical of a utility's management if a nearby utility is able to provide cheaper, cleaner, or more reliable service.

This creates a form of indirect competition that helps regulators monitor utility behavior and push for improved price and service. Public utility commissions look at the rates and services similarly situated utilities provide to establish benchmarks for the utilities under their supervision. For example, Hempling describes how, before Pepco, a utility based in the District of Columbia, merged with Baltimore Gas & Electric (BG&E), BG&E's ability to restore customer power after storms was used as a benchmark to encourage Pepco to improve its emergency services.[58] After the two companies merged, the two firms stopped being rivals, and such comparisons became less meaningful. Notably, California blocked a proposed merger between Southern California Edison and San Diego Gas & Electric in part out of concern that the merger would undermine "the companies' longstanding across-the-fence rivalry."[59] While certainly not a perfect substitute for robust competition, across-the-fence rivalry creates at least some accountability for rate regulated utilities.

Hempling is particularly concerned with utility mergers and acquisitions that "eliminate mavericks,"[60] which are "firm[s] that play[] a disruptive role in the market to the benefit of customers."[61] Mavericks can create benefits by pioneering new technologies, reducing prices, and refusing to engage in collusive tactics.[62] A maverick can provide important information to utility regulators, since the ability of one utility to cut costs, improve services, or transition to a less carbon-intensive fuel mix could suggest that other utilities would be able to do so as well. Maverick electric utilities can therefore create ambitious benchmarks that push other utilities to improve their own behavior.

Acquisitions reduce the number of utilities that can be used as a benchmark when regulators are setting new rates. The result is fewer data points that can be used to provide baseline data points that energy regulators can use when reviewing utility rates and services.

But utility acquisitions are particularly problematic when the target is a maverick, since the acquisition eliminates a company that provided evidence that

58. *Id*. at 193.

59. *Id*.

60. *Id*. at 188.

61. *See* FTC, HORIZONTAL MERGER GUIDELINES, 2.1.5, https://www.justice.gov/atr/horizontal-merger-guidelines-08192010.

62. *See id.*; HEMPLING, REGULATING MERGERS AND ACQUISITIONS, *supra* note 1, at 188.

other utilities could provide better service or lower prices. As a result, the acquisition of a maverick utility can reduce regulatory pressure other utilities face, because it eliminates an important datapoint for utility regulators.

It is worth nothing that this harms the market as a whole and not just the customers of the parties to the transaction. When a maverick utility is acquired, it is not just the acquirer that benefits from eliminating a company that was invoked to pressure the acquirer to reduce rates and services. Every utility in the country benefits when a merger or acquisition eliminates a maverick that was an environmental steward or provided low rates.

* * *

This is not a comprehensive list of distortions created by the deferential posture FERC and many state public utility commissions have taken toward utility mergers. Cross-subsidization and information deficits are interesting, perhaps, because they are consistent with the idea, which Hempling emphasizes throughout *Regulating Mergers and Acquisitions of U.S. Electric Utilities*, that utility mergers raise unique issues that do not come up in competitive markets.

It is also worth noting that the two challenges described in this Review compound each other. A regulator with perfect information about a utility's costs might be able to prevent the utility from cross-subsidizing non-utility affiliates. But if it lacks information about the utility's costs, it will be less able to determine when a particular inter-affiliate credit agreement constitutes a cross-subsidy, or when it is a simple credit enhancement negotiated at arm's length and for which the utility received adequate consideration. Similarly, if most electric utilities are owned by large holding companies, a regulator might be less able to detect cross subsidies of the sort described in the previous Part. If similarly situated utilities all cross subsidize their non-utility affiliates, regulators may find it more difficult to determine that a utility is cross-subsidizing its non-utility affiliates.

V. PROACTIVE MERGER REGULATION

To mitigate these distortions, Hempling proposes that energy regulators approach utility mergers and acquisitions more proactively.[63] This is a sensible proposal. As discussed, FERC can approve mergers and acquisitions only if it finds that the transaction is in the public interest. But in many situations, FERC and state regulators have no idea if a particular transaction will turn out to be in the public interest. A utility might promise future efficiency improvements, but unless FERC or a state public utility commission extracts concessions at the time of the acquisition, it is difficult to know whether an acquirer will increase operational efficiency, take advantage of the target's utility franchise to subsidize non-utility affiliates, or some combination of those two actions.

To ensure that utility mergers promote the public interest, Hempling argues that utility commissions should impose conditions on the terms of utility mergers and on the utility's post-merger behavior.[64] He suggests, for example, that regulators require meaningful rate reductions as a condition of merger approval, that

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63. *See* HEMPLING, REGULATING MERGERS AND ACQUISITIONS, *supra* note 1, at 407-23.
64. *Id.* at 410.

they require that holding companies treat utilities and non-utility affiliates as completely separate from each other, and that "the utility have the most advanced form of ring fencing" to ensure that the company does not use the utility to cross-subsidize non-utility affiliates.[65]

It is worth noting that this approach would yield benefits beyond the parties to the utility merger and those firms' customers. If utilities reduced prices, improved service, or shifted to a cleaner resource mix in order to secure merger approval, the utility could become a maverick. Regulators across the country could cite the consolidated firm as evidence that other regulated firms can reduce emissions, lower prices, or improve service. Hempling's proposal would thus generate useful information that could allow energy regulators to use yardstick competition. In doing so, it would mitigate many of the harms described in this Review and analyzed in *Regulating Mergers and Acquisitions of U.S. Electric Utilities*.[66]

65. *Id*. at 410-11.

66. For example, energy regulators may be able to reduce holding companies' ability to hide the costs of non-utility subsidiaries in utility rates by ordering arms-length bargaining and carefully scrutinizing finances, but no amount of oversight will substitute for structural separations, which makes it impossible for non-utility subsidiaries to bury costs in utility rates.

HOW TO AVOID A CLIMATE DISASTER

By Bill Gates
*Reviewed by Kenneth A. Barry**

I. INTRODUCTION

The first question Bill Gates confronts in his new book, *How to Avoid a Climate Disaster* (subtitled "The Solutions We Have and the Breakthroughs We Need")[1] is why a world-famous, unimaginably wealthy computer software innovator with no specific credentials in climate change science is authoring a book on this sprawling – and unquestionably vexing – subject. He explains that the project sprang from his charitable foundation's work in developing nations, including addressing "energy poverty." Apprehending that these communities could not reach goals to improve their education, health, and economies while burning wood and candles to cook, heat, or read, Gates initiated his search for practical solutions.[2]

At roughly the same time, Gates was drawn into the work of former Microsoft colleagues on the linkages between energy consumption and global warming. Merging these two projects, Gates was struck that the third-world challenge was two-fold: poor countries not only needed new, affordable, and reliable sources of energy, but these resources had to be "clean," particularly since much of the increasing demand for energy would be coming from developing nations.[3]

As Gates launched a self-guided study of climate science, he shed his initial skepticism that the accumulation of atmospheric greenhouse gases (GHG) would, if unabated, place the planet on an irreversible course towards unsustainably high temperatures.[4] The author emerged with four conclusions that have since shaped his new, self-appointed role as a climate change solutions activist and investor:[5]

- Not enough is currently being done to spur widescale deployment of wind and solar energy;
- Regardless of that deficit, these technologies alone will be insufficient to reach the net zero-carbon goal Gates has embraced;

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1. BILL GATES, HOW TO AVOID A CLIMATE DISASTER: THE SOLUTIONS WE HAVE AND THE BREAKTHROUGHS WE NEED (2021).
2. *Id.* at 4-5.
3. *Id.* at 6-7.
4. *Id.* at 7. Amusingly, the celebrated author here notes that an invaluable text in accelerating his learning curve was *Weather for Dummies.*
5. *Id.* at 8.

- Since power generation accounts for only slightly over a quarter of global GHG emissions,[6] the focus of curtailing emissions has to go far beyond the electric power industry;
- New, 'breakthrough" technologies across a wide front must be developed and deployed, through a synergistic coalescence of public policy and private investment.

Gates's journey to becoming a dedicated climate change advocate also evolved from his earlier activity as a venture capitalist placing bets on clean energy concepts (including "next-generation" nuclear power).[7] Around 2015, he was drawn into the politics of global warming by (1) student protests against institutions investing in fossil fuel companies (including his own Gates Foundation); and (2) overtures from heads-of-state as the December 2015 date of the Paris climate change approached.[8] The latter triggered an abiding interest – one at the heart of *How to Avoid a Climate Disaster* – in the intersection between governmental policy, public funding of clean energy research, and private investment in decarbonizing product development.[9] Soon, Gates found himself organizing a large circle of wealthy investors – dubbed the Energy Breakthrough Coalition – providing badly needed venture capital to promising clean energy technologies, as well as interfacing with political leaders to enhance national R&D budgets.[10] In short, Gates had found his niche in the clean energy game.

But how can a multi-billionaire with an extravagant lifestyle develop "street cred" with the environmental community? In a preemptive strike, Gates pleads guilty to being a super-emitter in his personal and business life, owning multiple large residences and regularly globe-trotting in private jets.[11] However, he asserts that (1) he has more than made up for these sins with his investments – now totaling over $1 billion – in technologies to produce low or zero-carbon energy (and other products); and (2) he knows of no one who has invested more heavily in methods to remove carbon dioxide directly from the atmosphere.[12]

II. SETTING THE TABLE

Near the outset, Gates suggests that two crucial components for avoiding a climate disaster are already present: (1) public enthusiasm – exemplified by "a growing global movement led by young people;" and (2) an increasing level of commitment from national and local leaders.[13] What Gates finds most lacking is

6. Gates's use of the terms GHG and "carbon" emissions includes not only the carbon dioxide associated with burning fossil fuels, but also other, more potent GHG emissions such as methane.

7. GATES, *supra* note 1, at 8.

8. *Id.* at 9-10. Gates explains that he wasn't swayed by the protests, as the world's energy industry was deeply entrenched and divestment – the goal of the protests – was an empty gesture. However, he later divested, simply so he wouldn't have a personal incentive at crosscurrents with his efforts to incubate new, cleaner technologies.

9. *Id.* at 11.

10. *Id.* Gates here reports that the governmental budget reboot stimulated by the Paris climate change accords was a signal success that "unlocked $4.6 billion a year in new money for clean energy research."

11. *Id.* at 15.

12. GATES, *supra* note 1, at 15.

13. *Id.* at 17.

a "concrete plan" that pulls together the numerous scientific, engineering, and financial disciplines necessary to realize his ambitious goal of zero net carbon emissions by mid-century.[14] Filling this gap is a core mission of *How to Avoid a Climate Disaster*.

But prior to delineating the path to planetary salvation, Gates gives us a tour of the living hell awaiting civilization if it doesn't act, radically and urgently, to decelerate emissions causing global warming. His first chapter, "Why Zero?", is a catalog of environmental calamities climate change researchers have been predicting for years should warming continue much beyond the one degree Celsius rise already recorded since pre-industrial times.[15] This part of the book is obviously derivative – Gates accepts, rather than reassesses, the projections of legions of climate scientists – but he does do an effective job of blending them into a coherent tableau, embellished with photographs and relatively uncomplicated charts. The picture is one of increasingly frequent weather abnormalities and ecological dislocations, in which agriculture and livestock rearing become more challenging, storms more intense, beaches and low-lying cities less inhabitable, marine life stressed, and entire communities splintered or uprooted. Along with more prolonged heat waves, shifting rainfall patterns either soak or parch the land; settlements and nations most dependent on subsistence farming perversely become the hardest hit; and forced population migrations far exceed current levels.[16]

Gates acknowledges the inherent uncertainty in the welter of climate change prognostications, conceding scientists still have "a lot to learn about how and why the climate is changing."[17] But he does not mince words on the bottom line: "The earth is warming, it's warming because of human activity, and the impact is bad and will get much worse. We have every reason to believe . . . the impact will be catastrophic."[18]

Gates hedges somewhat on his early suggestion that the cornerstones of public enthusiasm and political commitment are already firmly in place. In the chapter titled "This Will be Hard," he first observes that existing environmental laws in the U.S. are "outdated" with respect to climate change[19] and that the nation's quadrennial election cycles are prone to put ongoing government support for long-term investments in green technologies on a shaky footing.[20] He's concerned that "[t]here isn't as much of a climate consensus as you might think."[21] His contention here is that, while many now recognize climate change as a valid concern, when it comes to "investing large amounts of money in breakthroughs," public support tends to wane, or take a back seat to investing in education and

14. *Id.*

15. *Id.* at 18 *et seq.* Gates notes that, while the global average increase is just one degree Celsius so far, some places in continental interiors have seen a two-degree rise. *Id.* at 21.

16. *Id.* at 25-34.

17. GATES, *supra* note 1, at 24.

18. *Id.* at 25.

19. *Id.* at 48.

20. *Id.*

21. *Id.* at 49-51.

health.[22] In the same vein, Gates asserts that global cooperation – a critical element in any truly comprehensive climate change strategy – is "notoriously difficult." He bluntly concludes: "We need to build a consensus that doesn't exist and create public policies to push a transition that would not happen otherwise."[23]

III. GETTING ARMS AROUND THE PROBLEM

Gates offers in a chapter entitled "Five Questions to Ask in Every Climate Conversation" various frameworks and tools for evaluating potential investments in GHG emission solutions, helping him to cut through the mass of data.[24] One organizing principle is to boil down all sources of emissions into five broadly simplified categories, listed in order of their relative contributions to total GHG emissions. His matter-of-fact labels for these categories are: (1) *Making things* (31%); (2) *Plugging in* (27%); (3) *Growing things* (19%); (4) *Getting around* (16%); and (5) *Keeping warm and cool* (7%). As to the electric generation sector that draws so much attention in climate change discussions – *i.e.,* "Plugging in" – Gates proposes that this category can contribute more to reducing GHG emissions than its 27% proportionate contribution would indicate. He sees such potential not just in displacing fossil fuel-burning generation with low-carbon power, but also in electrifying energy utilization in other categories (*e.g*., transportation, space heating/cooling, natural gas-based processes in manufacturing).[25]

Another analytic tool Gates enthusiastically recommends is what he calls the "Green Premium." As a realistic businessman, Gates does not advocate embracing new technologies simply because they are "greener." Rather, he wants to pinpoint the Green Premium: what the incremental cost may be to substitute a low-carbon energy application for one using fossil fuels. If the premium is small, or even negative (*i.e.*, cheaper than fossil fuels), that supports the case for near-term investment and deployment. However, if the premium is sizeable, that signals the need for "breakthrough" technologies along with the investment to attain them.[26] Notably, Gates resists the premise that zero-carbon power generation (*i.e.*, wind and solar) are already fully competitive with conventional fuels. "By and large," he states, our current energy technologies are "the cheapest ones available . . . . [s]o moving our immense energy economy from 'dirty' . . . technologies to ones with zero emissions will cost something."[27]

22. GATES, *supra* note 1, at 49-51.

23. *Id.* at 51. While this warning about the difficulty of getting broad global commitment seems to cut against Gates's previous proclamation that world leader commitment is growing, the distinction seems to be in getting universal buy-in. Thus, his disappointment in the Trump Administration's withdrawal from the 2015 Paris Accords (reversed in 2021 by the new Biden Administration): Gates concedes that the national commitments in Paris were not nearly deep enough to stem climate change but were at least "a starting point that proved global cooperation is possible."

24. *Id.* at 52-55.

25. *Id.* at 55.

26. *Id.* at 59-61.

27. GATES, *supra* note 1, at 58. Gates does not distinguish here between existing, conventional power plants and newbuilds in his generalization that current, fossil-fuel energy technologies are the cheapest. He

He uses the Green Premium to illustrate the expense hump airlines (or their customers) would face in converting from conventional, petroleum-based jet fuel to available, but over twice-as-expensive "advanced biofuels," rhetorically asking, "How much are we willing to pay to go green?"[28] The Green Premium tool is nonetheless "a fantastic lens," Gates enthuses, for making practical decisions on whether to deploy existing low-carbon technologies or continue the quest for more affordable breakthroughs.[29] As a caveat, Gates points out that some Green Premiums may be presently affordable for wealthier countries but not for middle- or low-income ones.[30]

IV. GREENING UP THE GRID

The chapter titled "How We Plug In" – Gate's outlook for decarbonizing the electric grid – may be of the most interest to readers of the *Energy Law Journal*, especially given his belief that the power sector can make an outsized contribution in reducing overall GHG emissions. Here, Gates treads carefully. Perhaps to the disappointment of some environmental advocates, he dwells on the limitations of solar and wind energy in shouldering the bulk of generation, given the intermittency of these technologies and the insistence of modern civilization on near-perfect reliability.

After laying out some electricity basics for lay readers, Gates digs into the problem by underscoring that, currently, about two-thirds of the world's energy is generated with fossil fuels (largely coal and natural gas)[31] – mainly because "fossil fuels are cheap."[32] Plus, he relates, it is an *increasing* trend, as China has, since 2000, been building coal-fired capacity apace, tripling the amount of coal power it uses.[33] On the other hand, Gates suggests that it is feasible, at least for the United States and Europe, to "eliminate our emissions with only a modest Green Premium."[34] It is important to keep in mind, however, that the decarbonized generation fleet Gates envisions *includes* nuclear stations and fossil fuel-burning units equipped with carbon capture technologies.[35]

In asserting that the Green Premium is manageable in the United States, Gates calculates that the typical household bill would go up by only around 15%,

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does underscore that his cost comparisons do not take into account any harm caused to the environment by burning hydrocarbons.

28. *Id.* at 60.

29. *Id.* at 61.

30. As a self-described "thought experiment," Gates also imagines what it would cost to remove the annual global GHG emissions – currently 51 billion tons – via direct air capture (DAC), and comes up with a ballpark figure of $5.1 trillion/year. DAC would be much less expensive than shutting down entire segments of the world economy, as happened in the Covid-19 crisis, Gates observes, but he doesn't see it as practical solution anytime soon. *Id.* at 63-64.

31. *Id.* at 70.

32. GATES, *supra* note 1, at 70.

33. *Id.* at 72. Gates adds that this is "more capacity than in the United States, Mexico, and Canada combined." though he doesn't clarify whether he means all types of installed generation capacity or just coal, nor does he distinguish between "use" and "capacity."

34. *Id.*

35. *Id.*

or $18/month.[36] Other countries, he posits, may not be so lucky, as their solar and wind resources may not be as favorable as those in the United States. Moreover, Gates worries about China marketing its own business model – building inexpensive coal-fired plants – to the rest of the developing world to grow their power industries.[37] If third-world nations follow in China's footsteps, Gates opines, "it'll be a disaster for the climate."[38] This bleak prospect propels Gates's relentless pursuit of *affordable* green generation options.

The next question Gates tackles is why solar and wind generation entail *any* Green Premium, since their "fuel" comes free?[39] He advances several reasons, but the "biggest driver," he states, is "the curse of intermittency," coupled with the expectation of high reliability in first-world nations.[40] His analysis touches on the challenges – cost and otherwise – of massively augmenting the transmission network, along with the prohibitive (in Gates's view) expense of batteries systems robust enough to offset the intermittency of solar and wind resources.[41] Diurnal and seasonal swings in solar and wind output are a related problem; Gates cites Germany as a case study in the dislocations caused by both over- and under-generation of renewables, when a country commits to producing more than half of its energy with such resources.[42]

Having sketched out the inherent difficulties in relying too heavily on solar and wind power, Gates recognizes these technologies still need to play "a substantial role in getting us to zero" and therefore recommends the removal of barriers to deploying them "wherever it's economical."[43] He closes the discussion with a plea for more national planning of transmission grids, and upgrading the existing transmission and distribution networks, if there is any hope for states (such as New York and California) reaching their lofty goals for green energy dominance within a decade.[44]

In a pitch for increasing reliance on nuclear energy, Gates maintains "it's hard to foresee a future where we decarbonize our power grid affordably without using more nuclear power."[45] As a founder of TerraPower, a company devoted to creating advanced nuclear designs capable of addressing the well-publicized

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36. *Id.* Gates includes the "wires" cost – which can compose half or more of the total household power bill – in the denominator to calculate just a 15% Green Premium. If delivery costs are set aside, the projected Green Premium would be about double. Either way, the Green Premium would be higher for industrial and commercial end users with their typically higher load factors, as their generation-driven costs compose a larger percentage of the total bill.

37. Gates notes that Chinese companies "drove down the cost of a coal plant by a remarkable 75%." GATES, *supra* note 1, at 73.

38. *Id.* at 74.

39. *Id.*

40. *Id.* at 75.

41. *Id.* at 75-79.

42. Over-generation in Germany in the summer of 2018, he relates, caused the dual problems of straining the grid connections with its European neighbors to the south and "causing unpredictable swings" in energy costs. GATES, *supra* note 1, at 78.

43. *Id.* at 81.

44. *Id.* at 82-84.

45. *Id.* at 85.

safety and cost concerns about nuclear,[46] Gates qualifies as an informed proponent. His survey continues with a series of pocket-sized profiles on still other emerging technologies: nuclear fusion, offshore wind, geothermal generation, and storage methods (batteries, pumped hydro, thermal storage, and hydrogen fuel cells).[47] Notwithstanding Gates's fondness for engineering innovation, there is nothing starry-eyed about these capsule summaries; he touches on the potential, but also the obstacles facing each concept in becoming a mainstream contributor to the grid.

V. DECARBONIZING TRANSPORTATION

Yet another tough nut to crack in Gates's view is the prevalence of oil-derived fuels for cars, trucks, ships, and airplanes. While the transportation sector is only the fourth-largest contributor to GHG emissions, he notes (coming in at 16%), it ranks as the largest emitter in the United States – where gas is "remarkably cheap."[48] It adds to the challenge that the growth in emissions among OECD nations[49] is not in the automobile and light truck sector – that is falling in the United States and the European Union – but rather in the modes of transportation least susceptible to electrification: aviation, trucking, and shipping.[50] Meanwhile, most of the growth in transportation-driven emissions is coming from the less-developed countries whose populations are growing and economies expanding, meaning more people are buying personal vehicles.[51]

Electrification of the ground vehicle fleet is the most obvious answer, and Gates notes that a lengthy roster of global manufacturers is producing electric vehicles (EVs).[52] Moreover, as efficiencies in batteries have improved and costs have come down (Gates mentions an 87% decrease since 2010), the Green Premium is "modest," he declares. In the pertinent chapter, Gates offers a comprehensive look at the advantages and drawbacks, along with the remaining challenges, of introducing EVs to the market in quantity.[53] Moreover, given that a billion or so cars are already on the road and the vast majority of these are *not* EVs,[54] the chapter considers the development of liquid biofuels and "electrofuels" capable of running internal combustion engines. Although Gates sees little environmental benefit in corn-based ethanol, he is excited by the prospect of "advanced, second-generation" biofuels produced from other crops.[55]

Examining the current Green Premiums for these emerging biofuels, however, Gates shows that the incremental costs are too sizeable for widespread

46. *Id.* at 86-87.

47. GATES, *supra* note 1, at 84-94.

48. *Id.* at 130-131.

49. The acronym stands of "Organization for Economic Cooperation and Development" and includes the United States and other developed nations.

50. GATES, *supra* note 1, at 132-133.

51. *Id.* at 133.

52. *Id.* at 135.

53. *Id.* at 135-137.

54. *Id.* at 135.

55. GATES, *supra* note 1, at 138.

adoption and, hence, more investment in their development is required. As to larger vehicles, Gates distinguishes between garbage trucks and city buses – whose medium size and predictable routes lend themselves to electrification – and 18-wheelers or long-distance buses, whose size and long-haul routes do not, at least with current battery technology and charging infrastructure.[56]

As to ships and airplanes, Gates's analysis likewise shows that batteries aren't up to the job, and the Green Premiums for alternate, low-carbon liquid fuels are too great for commercial adoption. His book calls for innovation to reduce these differentials, and floats the idea of nuclear-powered container ships, despite the conceded risks.[57]

VI. MANUFACTURING AND SPACE HEATING/COOLING[58]

Gates provides an extensive discussion of manufacturing processes that produce substantial amounts of GHG gas emissions – he focuses on steel, cement, and plastics to make his points – and on methods for heating and cooling buildings. While the book does not provide a deep dive into current and emerging technologies, Gates has enough to say on each of these topics to give readers a feel for the challenges and opportunities. A recurrent theme in the book is sounded loudly in the passages on manufacturing: the role of fossil fuels is pervasive, and reversing this is technically and economically daunting. However, this does not prevent Gates from suggesting innovations on the cusp of introduction or at least being contemplated in laboratories.[59]

Gates's advice is to:[60]

- Electrify everything capable of being electrified in the manufacturing process;
- Make sure the electricity being employed is decarbonized;
- Deploy carbon capture technologies to remove the rest of the emissions;
- Make more efficient use of materials.

Every one of these advancements is going to require "lots of innovation," he adds.[61]

On the space heating and cooling front, the Green Premium fares better, to the extent people have or will install electric heat pump equipment. Generally in the United States, this technology affords a *negative* Green Premium; in other words, its life-cycle costs are actually lower than the combination of a natural

56. *Id.* at 140-141.

57. *Id.* at 147.

58. For brevity, we will omit a discussion of agriculture and livestock rearing, a category which contributes a not inconsiderable 19% of total GHG emissions. However, it should be noted Gates applies the same comprehensive, pragmatic approach to challenges and opportunities in this as to the four other emissions categories more directly implicating the energy industry. Readers interested in climate change causes and solutions generally will find the relevant chapter, "How We Grow Things" (pp. 112-129) absorbing.

59. GATES, *supra* note 1, at 98-111.

60. *Id.* at 111.

61. *Id.*

gas furnace and electric air conditioning.[62] However, there are two thorny problems; first, heat pumps are currently in only 11% of American homes, while half run on natural gas; and second, their environmental benefits are realized only to the extent the electric generation fleet is decarbonized.[63]

These facts lead Gates to redouble his claim that advanced biofuels and electrofuels must be brought down to more affordable levels, so that furnaces designed to run on natural gas or fuel oil can be decarbonized.

The urgency of the issue is underscored by the accelerating deployment of air conditioning in developing countries, Gates notes. As the planet grows warmer, the growing demand for air conditioning exacerbates the problem of warming – a vicious cycle – unless the remedies outlined in the book take hold,[64]

VII. EXPANDING THE ROLE OF GOVERNMENT

In a chapter dissecting the critical role of government policymaking in combatting climate change, Gates admits to a touch of hypocrisy. It may seem "ironic," he acknowledges, that the former CEO of Microsoft, who regarded government and politics so warily and felt these forces only prevented his company "from doing our best work," is now attesting to the need for "more government intervention."[65] Gates offers a selective inventory of successful historic government interventions supporting his current thinking.[66]

Whatever one may think of the government's track record, Gates contends that "when it comes to massive undertakings . . . [such as] decarbonizing the global economy – we need the government to play a huge role in creating the right incentives and making sure the overall system will work for everyone."[67] National leaders must "articulate a vision," he argues, and "can write rules regarding how much carbon power plants, cars, and factories are allowed to emit."[68]

This may be strong stuff for readers who come at technological and economic problems from the point of view that markets are better at solving them than politicians and policy implementers, however well-intentioned. Nevertheless, *How to Avoid a Climate Crisis* makes its case by insisting that nations and the global economy are on a perilous course and that radical government intervention – characterized by well-conceived incentives as much as command-and-control measures, and crafted to catalyze private industry's skill at product development and commercialization – is necessary to pull out of the tailspin.

Gates maintains that the energy sector (utilities in particular) has a history of underinvesting in research and development compared with other industries.[69] And given the long lead times to perfect energy innovations, as well as the con-

62. *Id.* at 154.
63. *Id.* at 154-155.
64. GATES, *supra* note 1, at 150.
65. *Id.* at 183.
66. *Id.* at 182.
67. *Id.* at 183.
68. *Id.*
69. GATES, *supra* note 1, at 184-185.

siderable risk of failures, he envisions a major role for government in funding and spurring the kind of innovation necessary to make clean energy technologies affordable and thus competitive with systems they would replace.[70]

Coupled with Gates's cheerleading for investment in innovation to bring down the Green Premium is a somewhat contrary strain: Gates argues that governmental policy can "level the playing field" by imposing cost of externalities – that is, the assumed social cost of carbon to the environment – on fossil fuels or their products.[71] This would reduce the "Green Premium" – by increasing the cost of what "clean" energy applications and products must compete against. Gates defends this as a strategy to "nudge producers and consumers toward more efficient decisions" while encouraging innovation.[72] "You're a lot more likely to try to invent a new kind of electrofuel," he posits, "if you know it won't be undercut by artificially cheap gasoline."[73] Critics may assail this as moving the goalposts if you can't hit the field goal, but it is undeniably a policy tool governments worried about climate change are inclined to wield.

In his "Adapting to a Warmer World" chapter, Gates raises another haunting question: what if, despite all efforts, strenuous or not, we see climate change approaching dangerous levels? Should more drastic measures be employed if, as climate scientists have hypothesized, the planet reaches a "tipping point" that "could dramatically increase the rate at which climate change happens"?[74] Lest this happen, Gates advocates studying and potentially exploring "geoengineering" – meaning, the intentional release of fine particulars that would, at least in theory, deflect some of the sun, much like releases from a volcanic eruption, with cooling impact.[75] The author realizes this constitutes heresy to some environmentalists, but reveals he has been funding such studies, and submits the concepts are "worthy studying and debating while we have the [time for the] luxury of study and debate."[76]

VIII. CONCLUSION

Gates tells us a "concrete plan" is badly needed to organize and orchestrate meaningful GHG emission reductions, and he offers one.[77] He cautions against today's rhetoric urging "deep decarbonization" by 2030. This is "unrealistic," in his view, given how thoroughly fossil fuels permeate and enable modern existence,[78] and could be counterproductive.

70. *Id.*

71. *Id.* at 186.

72. *Id.*

73. *Id.*

74. GATES, *supra* note 1, at 176.

75. *Id.* at 176-177.

76. *Id.*

77. *Id.* at 196-217. Gates also refers readers to the website of his green venture capital coalition for more detail. *See* breakthroughenergy.org.

78. *Id.*

Instead, Gates advocates adopting *policies* in the near term that would put the world on a path to deep decarbonization by 2050.[79] Some interim goals for the coming decade – *e.g.*, pushing ahead with carbon-free generation and electrifying vehicles or industrial processes – are consistent with "zero carbon" by 2050, he maintains, so long as we avoid halfway measures that could cripple the 2050 goal.[80] Now is the time, Gates says, for nations to prioritize innovation in science and engineering, in supply chains and markets, to pave the way for a net zero carbon future.[81]

Gates's plan is not a treasure map – that would be too much to expect – but rather a business-oriented way of the laying the pathway. Drawing on his Microsoft experience, Gates divides the task into two main parts: expanding the *supply* of innovation, while nurturing and conditioning *demand* for it. After offering a long list of needed technologies, he prescribes a major ramp-up of public investment to pursue them and guidance on how to select priorities while forming "partnerships" with industry.[82] The same kinds of meticulous steps, coupled with market-sensitive incentives, must be taken in preparing the demand side (i.e., customers) for the uptake of "good ideas."[83] And government must take a lead role in building the infrastructure so that customers may access the benefits of new technology.[84]

In sum, Bill Gates has provided a determined yet realistic vision, a goldmine of facts, and an arsenal of recommendations to the indubitably complex task of confronting climate change across its many fronts. The book is surprising in its comprehensiveness and grasp of detail, while refreshing in avoiding the academic cant and the alphabet soup of acronyms that can so easily discourage non-specialist readers.[85] The diction and sentence structure are consistently plain and straightforward – especially helpful in a context involving such a myriad of technical information and concepts – occasionally accented with a dab of humor.

People who are already immersed in the science behind *How to Avoid a Climate Crisis* may disagree with some of Gates's assertions, and energy law specialists may trip across an error or two regarding their own field; but much credit is due to Gates for rolling up his sleeves and lending his name (and a good chunk of his fortune) to assessing and, he hopes, solving an issue as perplexing

79. GATES, *supra* note 1, at 196-217.

80. *Id.* at 197.

81. *Id.* at 198.

82. *Id.* at 200-202.

83. *Id.* at 203-204.

84. GATES, *supra* note 1, at 205. The "Plan for Getting to Zero" usefully delineates the important, sometimes overlapping, roles of the federal, state, and local governments and agencies – including the Federal Energy Regulatory Commission and the public utility commissions of the several states. Here, Gates praises state coalitions that picked up the fallen banner of the Paris accords, after President Trump withdrew the U.S. *See id.* at 210-214.

85. The reader may feel baffled how one person, especially someone whose early-to-middle career has been spent in other complex fields, can pull together such an informative and lucid work. At the end, in an "Acknowledgements" section, one learns that Gates has levered the work of many advisers, researchers, and a "writing partner," Josh Daniel, to accomplish his mission.

as any facing mankind in the 21st century. As an entry-level guide to the morass of information, predictions, and political hurdles surrounding climate change, it is ideal.

IMPROVING NATIONAL SECURITY ONE REPORT AT A TIME: FERC ORDER NO. 848

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I. INTRODUCTION

In recent years, there have been an increasing number of attacks by foreign cyber hackers on critical infrastructure in the United States.[1] Particularly since the COVID-19 pandemic, cyber threats have been on the rise globally across a variety

1. Brian Naylor, *Russia Hacked U.S. Power Grid – So What Will The Trump Administration Do About It?*, NAT'L PUB. RADIO: POLITICS (Mar. 2018), https://www.npr.org/2018/03/23/596044821/russia-hacked-u-s-power-grid-so-what-will-the-trump-administration-do-about-it.

of critical infrastructure sectors.[2] For example, some of the reported incidents show that a hacker attempted to poison the water supply of a small city in Florida,[3] cyber weapons leaked from U.S. sources (federal agencies, the private sector, and critical infrastructure),[4] and North Korea attempted to hack Pfizer for information regarding the COVID-19 vaccine.[5] Growing awareness for these types of issues has spurred movements to mitigate potential harms in a variety of ways, such as changing how voting machines work so that they no longer permit wireless connectivity.[6] With this increase in cyberactivity, the United States is paying even greater attention to the cybersecurity of our electricity grid, as nearly all industries depend on the energy sector.[7]

Notable cyberattacks on the energy industry include an event from the summer of 2017 where Russian hackers conducted a "multistage intrusion campaign" to gain access to the control system of a U.S. power plant through "common hacking techniques such as malware and spear-phishing."[8] According to the head of counterintelligence under the Director of National Intelligence during the Obama administration, these hackers were not just trying to observe the system.[9] He continued by stating that the hackers were essentially "placing the tools that they would have to place in order to turn off the power," and he does not believe the United States is prepared to deal with this type of threat.[10] Awareness regarding cybersecurity vulnerabilities, expanding existing securities, and removing existing

2. *See, e.g.*, Dan Lohrmann, *2020: The Year the COVID-19 Crisis Brought a Cyber Pandemic*, GOV'T TECH. (Dec. 2020), https://www.govtech.com/blogs/lohrmann-on-cybersecurity/2020-the-year-the-covid-19-crisis-brought-a-cyber-pandemic.html; MonsterCloud, *Top Cyber Security Experts Report: 4,000 Cyber Attacks a Day Since COVID-19 Pandemic*, PR NEWSWIRE: CISION (Aug. 2020), https://www.prnewswire.com/news-releases/top-cyber-security-experts-report-4-000-cyber-attacks-a-day-since-covid-19-pandemic-301110157.html; David Grober, *Roundup: COVID-19 Pandemic Delivers Extraordinary Array of Cybersecurity Challenges*, ZDNET: SPECIAL FEATURE (Nov. 2020), https://www.zdnet.com/article/roundup-the-coronavirus-pandemic-delivers-an-array-of-cyber-security-challenges/; Tope Aladenusi, *COVID-19's Impact on Cybersecurity*, DELOITTE: ARTICLES (Mar. 2020), https://www2.deloitte.com/ng/en/pages/risk/articles/covid-19-impact-cybersecurity.html.

3. Frank Bajak, Alan Suderman & Tamara Lush, *Hack Exposes Vulnerability of Cash-Strapped US Water Plants*, AP NEWS (Feb. 2021), https://apnews.com/article/business-water-utilities-florida-coronavirus-pandemic-utilities-e783b0f1ca2af02f19f5a308d44e6abb.

4. Terry Gross & Nicole Perlroth, *U.S. Cyber Weapons Were Leaked – And Are Now Being Used Against Us, Reporter Says*, NAT'L PUB. RADIO: NAT'L SEC. (Feb. 2021), https://www.npr.org/transcripts/966254916.

5. VOA News, *North Korea Hacked Pfizer to Steal COVID-19 Vaccine Data, South Korea Says*, VOA NEWS: COVID-19 PANDEMIC (Feb. 2021), https://www.voanews.com/covid-19-pandemic/north-korea-hacked-pfizer-steal-covid-19-vaccine-data-south-korea-says.

6. Maggie Miller, *Election Commission Approves New Guidelines to Secure, Update Voting Equipment*, THE HILL: POLICY (Feb. 2021), https://thehill.com/policy/cybersecurity/538216-election-commission-approves-new-guidelines-to-secure-update-voting..

7. CYBERSECURITY & INFRASTRUCTURE SEC. AGENCY, ENERGY SECTOR (Apr. 2021), https://www.cisa.gov/energy-sector.

8. Naylor, *supra* note 1.

9. *Id*.

10. *Id*.

barriers to information-sharing is becoming increasingly important where protecting our nation's critical infrastructure is concerned, particularly within the energy sector.[11]

Order No. 848, promulgated by the Federal Energy Regulatory Commission (FERC) in 2018, augmented the reporting requirements for various types of cyber-attacks on the electric grid[12] and addressed growing concerns about the vulnerability and cybersecurity of the electric grid.[13] Because maintaining a resilient grid is an integral part of the critical infrastructure within the United States,[14] FERC took steps to redefine key terms in the industry and reassess the previously-utilized reporting requirements used by North American Electric Reliability Corporation (NERC) in reporting attacks or breaches of security.[15] FERC also set out new guidelines for addressing both actual and attempted cyber incidents affecting the electric grid.[16]

While the overall costs and benefits of this rulemaking cannot yet be adequately determined,[17] through increasing awareness of threats to the nation's cyber assets, Order No. 848 has the potential to protect the nation from severe economic damage and even prevent human casualties.[18]

II. BACKGROUND

A. Authority and Execution

1. FERC

Through section 215 of the Federal Power Act (FPA), the Energy Policy Act of 2005 gave FERC the authority to certify an electric reliability organization (ERO) to "establish and enforce reliability standards for the bulk-power system, subject to [FERC's] review."[19] FERC had the authority to adopt Order No. 848, pursuant to section 215(d)(5) of the FPA,[20] which further provides that FERC can

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11. *See, e.g.*, Office of Elec., *DOE Office of Electricity Issues Request for Information for Bulk-Power System Executive Order*, DEP'T OF ENERGY (July 2020), https://www.energy.gov/oe/articles/doe-office-electricity-issues-request-information-bulk-power-system-executive-order; Securing the U.S. Bulk-Power Sys., 85 Fed. Reg. 41,023 (Dep't of Energy July 8, 2020) (notice for the request for information (RFI)).

12. Order No. 848, *Cyber Security Incident Reporting Reliability Standards*, 164 F.E.R.C. ¶ 61,033, at PP 1-7 (2018) [hereinafter Order No. 848].

13. *Id.*; AM. PUB. POWER ASS'N, SECURITY AND RESILIENCE (CYBER AND PHYSICAL) ISSUE BRIEF: GRID SECURITY (Jan. 2021), https://www.publicpower.org/policy/grid-security.

14. CYBERSECURITY & INFRASTRUCTURE SEC. AGENCY, *supra* note 7.

15. Order No. 848, *supra* note 12, at PP 1-7.

16. *Id.*

17. *Id.* at PP 29-30.

18. Testimony of the Foundation for Resilient Societies, FERC Reliability Tech. Conference, FERC Docket No. AD17-8-000 (June 22, 2017), https://www.resilientsocieties.org/uploads/5/4/0/0/54008795/thomas_popik_testimony_ferc_technical_conference_june_22_2017_filed__20170619.pdf [hereinafter Popik Testimony].

19. 16 U.S.C. § 824o(a)(2) (2005).

20. Order No. 848, *supra* note 12, at PP 1, 6.

require NERC "to submit to [FERC] a proposed reliability standard or a modification of a reliability standard that addresses a specific matter if [FERC] considers such a new or modified reliability standard appropriate to carry out this section."[21] FERC exercised this power in the promulgation of Order No. 848 because it surmised that the former cybersecurity reporting standards were not sufficiently identifying and classifying potential threats to the bulk electric system (BES).[22]

2. NERC

NERC is the electric reliability organization (ERO) for North America, subject to oversight by FERC.[23] NERC has a number of responsibilities, such as conducting risk management, assessing reliability, monitoring the power grid, and producing the aforementioned reliability standards.[24] The NERC Reliability Standards "define the reliability requirements for planning and operating the North American bulk power system and are developed using a results-based approach that focuses on performance, risk management, and entity capabilities."[25]

NERC implements FERC's regulatory delegation related to cybersecurity pursuant to the Critical Infrastructure Protection (CIP) Standards.[26] The CIP standards establish the minimal criteria required to protect, maintain, and recover the BES and its related critical cyber assets.[27] For context, under NERC's standards, any piece of technology could constitute a "cyber asset" if, within 15 minutes of its dysfunction, it "adversely impact[s] one or more [f]acilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the [BES]."[28] These standards have significantly changed over time, but each of the CIP standards that are directly

21. 16 U.S.C. § 824o(d)(5) (2005).

22. Order No. 848, *supra* note 12, at P 2.

23. NERC, ABOUT NERC (Apr. 2021), https://www.nerc.com/AboutNERC/Pages/default.aspx.

24. *Id.*

25. NERC, STANDARDS (Apr. 2021), https://www.nerc.com/pa/Stand/Pages/Default.aspx.

26. Order No. 706, *Mandatory Reliability Standards for Critical Infrastructure Protection*, 122 F.E.R.C. ¶ 61,040, at PP 1-13 (2008) (to be codified at C.F.R. pt. 40) [hereinafter Order No. 706]; *see also*, N. AM. ELEC. RELIABILITY CORP., CIP STANDARDS (Apr. 2021), https://www.nerc.com/pa/Stand/Pages/Default.aspx [hereinafter CIP STANDARDS].

27. Margaret Rouse & Ben Cole, *Definition: NERC CIP (Critical Infrastructure Protection)*, SEARCH COMPLIANCE (July 2012), https://searchcompliance.techtarget.com/definition/NERC-CIP-critical-infrastructure-protection.

28. N. AM. ELEC. RELIABILITY CORP., LESSON LEARNED CIP VERSION 5 TRANSITION PROGRAM: COMMUNICATIONS TO BES CYBER SYSTEMS AND BES CYBER ASSETS (Nov. 2015).

connected with the topics of focus within[29] are still actively enforced (though some of them have been modified and/or updated).[30]

B. Definitional History and Changes

On July 19, 2018, FERC issued Order No. 848, which expanded upon the mandatory reporting requirements for "cyber security incidents" in NERC's Reliability Standards.[31] Before FERC Order No. 848, a "cyber security incident" was defined by NERC as a "malicious act or suspicious event that compromises, or was an attempt to compromise, the Electronic Security Perimeter [(ESP)] or Physical Security Perimeter or, disrupts, or was an attempt to disrupt, the operation of a [Bulk Electric System (BES)] Cyber System."[32] "Cyber security incidents" were distinguished from "reportable cyber security incidents" based on whether the attack actually "compromised or disrupted one or more reliability tasks of a functional entity."[33] NERC has since updated its reliability standards to comply with Order No. 848.[34]

After the promulgation of FERC Order No. 848, NERC produced a compliance filing that was ultimately approved by FERC.[35] Some of the relevant changes included the definition of "cyber security incident," which was expanded to include foreign monitoring or breaches of security of the ESPs and Electronic Access Control or Monitoring Systems (EACMS) that were connected with medium

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29. Order No. 848, *supra* note 12, at PP 5, 11-12, 54. *See also, e.g.*, N. AM. ELEC. RELIABILITY CORP., CIP-008-5, CIP STANDARD: CYBER SECURITY – INCIDENT REPORTING AND RESPONSE PLANNING (Jul. 2014); N. AM. ELEC. RELIABILITY CORP., CIP-007-6, CIP STANDARD: CYBER SECURITY – SYSTEM SECURITY MANAGEMENT (Jan. 2016); N. AM. ELEC. RELIABILITY CORP., CIP-006-6, CIP STANDARD: CYBER SECURITY – PHYSICAL SECURITY OF BES CYBER SYSTEMS (Jan. 2016); N. AM. ELEC. RELIABILITY CORP., CIP-005-5, CIP STANDARD: CYBER SECURITY – ELECTRONIC SECURITY PERIMETER(S) (Nov. 2013); N. AM. ELEC. RELIABILITY CORP., CIP-002-5, CIP STANDARD: CYBER SECURITY – BES CYBER SYSTEM CATEGORIZATION (Nov. 2012); *see also* N. AM. ELEC. RELIABILITY CORP., CIP-008-6, CIP STANDARD: CYBER SECURITY – INCIDENT REPORTING AND RESPONSE PLANNING (Feb. 2019); N. AM. ELEC. RELIABILITY CORP., CIP-005-7, CIP STANDARD: CYBER SECURITY – ELECTRONIC SECURITY PERIMETER(S) (Nov. 2020); N. AM. ELEC. RELIABILITY CORP., CIP-002-5.1a, CIP STANDARD: CYBER SECURITY – BES CYBER SYSTEM CATEGORIZATION (Dec. 2016).

30. CIP STANDARDS, *supra* note 26.

31. Order No. 848, *supra* note 12, at P 1.

32. NERC, GLOSSARY OF TERMS USED IN NERC RELIABILITY STANDARDS, (updated Jan. 2, 2020), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

33. *Id*. "Cyber security incidents" used to include any sort of tampering—which could be as minimal as monitoring—whereas "reportable cyber security incidents" were characterized by whether those cyber events actually accomplished something in terms of disrupting reliability functions of either cyber assets or the BES.

34. NERC, CYBER SECURITY – INCIDENT REPORT TECHNICAL RATIONALE AND JUSTIFICATION FOR RELIABILITY STANDARD CIP-008-6, at 2 (Jan. 2019), https://www.nerc.com/pa/Stand/Project%20201802%20Modifications%20to%20CIP008%20Cyber%20Secur/CIP_Technical_Rationale_for_CIP-008_Final%20Ballot_Clean_01152019.pdf.

35. *Letter to Lauren Perotti & Marisa Hecht*, 167 F.E.R.C. ¶ 61,230, at P 1 (Jun. 20, 2019) https://www.nerc.com/FilingsOrders/us/FERCOrdersRules/Order%20Docket%20No.%20RD19-3-000.pdf.

to high impact BES Cyber Systems.[36] This expansion was likely in response to the ever-increasing frequency of foreign interference with cyber assets.[37]

ESPs and EACMSs were not previously protected under the definition of "cyber security incidents" but are now included because they are an integral part of maintaining cyber safety and resilience of the grid. ESPs "manage electronic access to BES Cyber Systems to support the protection of the BES Cyber Systems against compromise that could lead to misoperation or instability."[38] They are "the logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol."[39] Their purpose is to protect cyber assets, like EACMs, and to facilitate remote accessibility.[40]

EACMS "control electronic access to the ESP and play a significant role in the protection of high and medium impact BES Cyber Systems."[41] They can take many forms but are most recognizable for their roles as "firewalls, authentication servers, security event monitoring systems, intrusion detection systems and alerting systems."[42] The Notice of Proposed Rulemaking (NOPR) that proceeded Order No. 848 noted that the ultimate concern is that "once an EACMS is compromised, an attacker could more easily enter the ESP and effectively control the BES Cyber System or Protected Cyber Asset."[43] These modifications are enforced by NERC through its reliability standard, CIP-008-6.[44]

C. *Increase in Inter-Agency Communications*

On a related note, the final rule that FERC adopted increases the reporting requirements to include entities such as the Department of Homeland Security (DHS).[45] This is significant because it is a clear, measurable move to increase inter-agency communications and minimize security risks. The attacks of Sep-

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36. *Id.*

37. Daniel R. Coats, *Statement for the Record: Worldwide Threat Assessment of the US Intelligence Community*, SENATE SELECT COMM. ON INTELLIGENCE 5 (Jan. 29, 2019), https://www.dni.gov/files/ODNI/documents/2019-ATA-SFR---SSCI.pdf.

38. Order No. 848, *supra* note 12, at P 10.

39. NERC, GLOSSARY OF TERMS USED IN NERC RELIABILITY STANDARDS (updated Jan. 2, 2020), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

40. NERC, LESSON LEARNED CIP VERSION 5 TRANSITION PROGRAM: COMMUNICATIONS TO BES CYBER SYSTEMS AND BES CYBER ASSETS (2015).

41. Order No. 848, *supra* note 12, at P 10.

42. *Id.*

43. *Id.*

44. NERC, CYBER SECURITY – INCIDENT REPORT TECHNICAL RATIONALE AND JUSTIFICATION FOR RELIABILITY STANDARD CIP-008-6, at 2 (Jan. 2019), https://www.nerc.com/pa/Stand/Project%20201802%20Modifications%20to%20CIP008%20Cyber%20Secur/CIP_Technical_Rationale_for_CIP-008_Final%20Ballot_Clean_01152019.pdf.

45. Order No. 848, *supra* note 12, at P 3.

tember 11, 2001, highlighted some severe failings regarding inter-agency communications.[46] This final rulemaking has pointed out that FERC has the goal of improving "awareness of existing and future cyber threats and potential vulnerabilities"[47] and ultimately, that providing more specific and exhaustive information on cyber incident attempts "will likely better assist the industry in preventing successful cyber-attacks."[48]

D. Order 848

1. Pertinent Language of the Promulgated Rule

This final rulemaking, in short, requires NERC "to develop and submit modification to the NERC Reliability Standards."[49] It states that:

> (1) responsible entities must report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS; (2) required information in Cyber Security Incident reports should include certain minimum information to improve the quality of reporting and allow for ease of comparison by ensuring that each report includes specified fields of information; (3) filing deadlines for Cyber Security Incident reports should be established once a compromise or disruption to reliable BES operation, or an attempted compromise or disruption, is identified by a responsible entity; and (4) Cyber Security Incident reports should continue to be sent to the Electricity Information Sharing and Analysis Center (E-ISAC), rather than the Commission, but the reports should also be sent to the Department of Homeland Security (DHS) Industrial Control Systems Cyber Emergency Response Team (ICS-CERT).[50]

E. NERC's Implementation Directed by FERC

To enforce Order No. 848, FERC ordered NERC "to develop and submit Reliability Standard requirements" that met the aforementioned four directives.[51] The first directive is that "responsible entities [must] report Cyber Security Incidents that compromise, or attempt to compromise, a responsible entity's ESP or associated EACMS."[52]

The second requirement is that NERC must "specify the required information in Cyber Security Incident reports."[53] NERC has now implemented this change and deleted confusing requirements from earlier CIP standards and to consolidate them into one rule, R4 of CIP-008-6, in order to satisfy FERC's intentions behind

46. 9/11 COMM'N REPORT: FINAL REPORT OF THE NATIONAL COMMISSION ON TERRORIST ATTACKS UPON THE UNITED STATES, NAT'L COMM'N ON TERRORIST ATTACKS UPON THE UNITED STATES, https://govinfo.library.unt.edu/911/report/911Report_Exec.htm.

47. Order No. 848, *supra* note 12, at P 6.

48. *Id.* at P 23.

49. *Id.* at P 1.

50. *Id.* at P 3.

51. *Id.* at P 16.

52. Order No. 848, *supra* note 12, at P 16.

53. *Id.*

Order No. 848.[54] R4 now also addresses the required reportable incident attributes, methods for submitting notifications, notification timing, and notification updates.[55] This rule became effective on January 1, 2021.[56]

Additionally, NERC has "establish[ed] deadlines for filing Cyber Security Incident reports that are commensurate with incident severity."[57] This is an important point in response to some of the concerns expressed by various agencies regarding the burden and usefulness of reporting, which will be discussed later in greater detail. R4 provides for two separate reporting deadlines, one for "reportable" cybersecurity incidents, and the other for more general attempts to compromise systems.[58] Accordingly, reportable cybersecurity deadlines must be reported within an hour, in accordance with CIP-008-5, and NERC provides that attempts to compromise a cyber system must be reported within a calendar day.[59] Correlating the reporting deadline with incident severity is a flexible way in which agencies could more easily accommodate their work load and prioritize their efforts and finite resources.[60]

Finally, Cyber Security Incident reports must "be sent to ICS-CERT, in addition to E-ISAC" and NERC must "file with the Commission an annual, public, and anonymized summary of such reports."[61] In the draft of R4, NERC did not provide for a mandatory method of reporting incidents and instead directed that the relevant entities "focus on incident response itself and not the method or format of reporting," so long as it meets the other requirements under the Reliability Standard.[62]

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54. NERC, CYBER SECURITY – INCIDENT REPORT TECHNICAL RATIONALE AND JUSTIFICATION FOR RELIABILITY STANDARD CIP-008-6, at 4 (Jan. 2019), https://www.nerc.com/pa/Stand/Project%20201802%20Modifications%20to%20CIP008%20Cyber%20Secur/CIP_Technical_Rationale_for_CIP-008_Final%20Ballot_Clean_01152019.pdf; 167 F.E.R.C. ¶ 61,230 Docket No. RD19-3-000 (June 2019), https://cms.ferc.gov/sites/default/files/2020-04/E-2_8.pdf.

55. *Id. See also* current NERC standard CIP-008-6 at; https://www.nerc.com/_layouts/15/PrintStandard.aspx?standardnumber=CIP-008-6&title=Cyber%20Security%20%E2%80%94%20Incident%20Reporting%20and%20Response%20Planning&Jurisdiction=United%20States.

56. NERC, MANDATORY STANDARDS SUBJECT TO ENFORCEMENT, https://www.nerc.net/standardsreports/standardssummary.aspx# (last visited Apr. 9, 2021).

57. Order No. 848, *supra* note 12, at P 16.

58. NERC, CYBER SECURITY – INCIDENT REPORT TECHNICAL RATIONALE AND JUSTIFICATION FOR RELIABILITY STANDARD CIP-008-6, at 5 (Jan. 2019), https://www.nerc.com/pa/Stand/Project%20201802%20Modifications%20to%20CIP008%20Cyber%20Secur/CIP_Technical_Rationale_for_CIP-008_Final%20Ballot_Clean_01152019.pdf.

59. *Id.*

60. Order No. 848, *supra* note 12, at P 52.

61. *Id.* at P 16.

62. NERC, CYBER SECURITY – INCIDENT REPORT TECHNICAL RATIONALE AND JUSTIFICATION FOR RELIABILITY STANDARD CIP-008-6, at 5 (Jan. 2019), https://www.nerc.com/pa/Stand/Project%20201802%20Modifications%20to%20CIP008%20Cyber%20Secur/CIP_Technical_Rationale_for_CIP-008_Final%20Ballot_Clean_01152019.pdf.

Before this change, Cyber Security Incidents were reported under NERC's Reliability Standard CIP-008-5.[63] This standard is different from the proposal because it only required that an entity report incidents that actually managed to "compromise[] or disrupt[] one or more reliability tasks."[64] FERC explained that this reporting standard did not accurately depict "the true scope of cyber-related threats facing the [BES]" and that many cyber-attacks, or attempted cyber-attacks, were not meeting the minimum criteria to require reporting.[65] One of the main pieces of evidence to support FERC's conclusion was the fact that there were no reportable cybersecurity incidents during 2015 and 2016, meaning that no attacks resulted in a loss of load.[66] NERC, in a Reliability Report on the subject, noted that the lack of reportable incidents did not necessarily mean that there was a low or minimal risk of cybersecurity incidents.[67]

F. Policy of the Order

The NOPR set three (3) minimum attributes that should be used when reporting incidents, so as to "improve awareness of cyber threats to BES reliability."[68] The first is to include the achieved or *attempted* functional impact of the Cyber Security Incident.[69] The second mandates that "the attack vector used to attempt or achieve the Cyber Security Incident" be included.[70] The final suggested attribute goes to "the level of intrusion achieved or attempted by the Cyber Security Incident."[71]

1. Comments

One of the major concerns highlighted from the comments to the NOPR was whether or not augmenting the reliability standard would unduly burden the industry.[72] NERC agreed with increasing the reporting requirements under the NOPR and provided that it would "help enhance awareness of cyber security risks facing entities" and that it "would create a more extensive baseline understanding the nature of cyber security threats and vulnerabilities."[73] This is consistent with the goal NERC provided in its 2017 State of Reliability Report as well.[74] NERC, however, did not support the NOPR regarding enhancing reporting requirements through a Reliability Standard.[75]

63. Notice of Proposed Rulemaking, *Cyber Security Incident Reporting Reliability Standards,* 82 Fed. Reg. 61,499 (Dec. 28, 2017), 161 F.E.R.C. ¶ 61,291, at P 1 (2017).

64. Order No. 848, *supra* note 12, at P 2.

65. *Id.*

66. *Id.* at P 9.

67. *Id.*

68. *Id.* at P 13.

69. Order No. 848, *supra* note 12, at P 13.

70. *Id.*

71. *Id*.

72. *Id.* at PP 22-30.

73. *Id*. at P 22.

74. Order No. 848, *supra* note 12, at P 22.

75. *Id*.

There were many supporters of broadening the definition of "Reportable Cyber Security Incidents" on the policy grounds that having better definitions would help prevent cyberattacks.[76] These supporters did have some worries and suggestions.[77] Some of the supporting entities believed that there was a "risk of over-reporting," that reporting attempts regarding "an ESP or associated EACMS 'needs further clarification,'" that some of the information reported might not be useful, and that there should be further guidance on what constitutes an "attempt."[78]

2. Outcome

FERC ultimately adopted the NOPR proposal, agreeing with NERC and other commenters "that enhanced reporting of Cyber Security Incidents will address an existing gap in Cyber Security Incident reporting and will provide useful information on existing and future cyber security risks, as well as provide entities with better visibility into malicious activity prior to an event occurring."[79] There were also some concerns that the new reporting requirements could divert resources away from other important programs.[80] FERC rejected this position because "responsible entities are already required to monitor and log successful login attempts, detected failed access attempts, and failed login attempts under Reliability Standard CIP-007-6, Requirement R4.1."[81]

Worries were also expressed regarding the minimum requirement for reporting a Cyber Security Incident.[82] Commenters repeated their concerns about the burden of setting certain threshold reporting requirements, but FERC ultimately decided to set a "compromise or attempted compromise of an ESP as the appropriate threshold for a Reportable Cyber Incident."[83] FERC agreed with several of the comments regarding the need for building flexibility into the reporting standard, and it suggested a system that reflects the severity of the incident with its reporting deadlines.[84]

G. Significance in the United States

BES disturbances are a matter of national security with potentially dire consequences, as can be seen with the blackout that occurred in Ukraine in December of 2015.[85] The Ukraine cyber-attack cut off the power going to 225,000 people in

76. Order No. 848, *supra* note 12, at P 23.

77. *Id*.

78. *Id*.

79. *Id.* at P 31.

80. *Id.* at P 33.

81. Order No. 848, *supra* note 12, at P 34.

82. *Id.* at PP 34-51.

83. *Id.* at P 52.

84. *Id*.

85. Kim Zetter, *Inside the Cunning, Unprecedented Hack of Ukraine's Power Grid*, WIRED (Mar. 3, 2016), https://www.wired.com/2016/03/inside-cunning-unprecedented-hack-ukraines-power-grid/ [hereinafter Zetter, *Inside the Hack of Ukraine's Power Grid*].

western Ukraine, depriving them of critical heating in the harsh winter months.[86] The Ukraine attack was described as "a premeditated and multi-level invasion," but one that was "not meant to be large scale."[87] Even several months after that infamous attack, power providers were still having difficulties maintaining stability and returning to normal usage.[88]

Since the Ukraine attack and others like it, the Pentagon has conducted tests to determine what could happen in a worst-case-scenario attack on the United States power grid.[89] Researchers simulated what it would be like for the power grid to be inoperable and what measures it would take to resume reliable operation.[90] The study showcased how difficult that task can be and what effects a large-scale blackout could have on the United States.[91] For instance, government or military officials might have to pick and choose which critical assets (such as hospitals and military bases) to provide power to during an event.[92] Or, for example, following a nuclear terrorist attack, power would be most important to first-responders and military officials.[93] The unique interdependencies of critical infrastructure within the United States today can "expose new vulnerabilities" when faced with terrorism or other interruptions.[94] Thus, communication between governmental actors and the private sector becomes crucial for stabilization.[95]

The first notable cyber-attack on the United States power grid occurred on March 5, 2019.[96] Luckily, this attack did not result in any blackouts or harm power generation, although it did have some slight effect on the Western transmission grid.[97] A director of intelligence analysis at a cybersecurity firm notes that the power grid touches nearly every part of a modern North American's day and that "many other critical infrastructure sectors rely on electricity."[98]

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86. Pavel Polityuk, Oleg Vukmanovic & Stephen Jewkes, *Ukraine's Power Outage Was a Cyber Attack: Ukrenergo*, REUTERS (Jan. 18, 2017), https://www.reuters.com/article/us-ukraine-cyber-attack-energy/ukraines-power-outage-was-a-cyber-attack-ukrenergo-idUSKBN1521BA.

87. Order No. 848, *supra* note 12, at P 52.

88. Zetter, *Inside the Hack of Ukraine's Power Grid*, *supra* note 85.

89. Joseph Marks, *Pentagon Researchers Test 'Worst-Case Scenario' Attack on US Power Grid*, DEFENSE ONE (Nov. 14, 2018), https://www.defenseone.com/technology/2018/11/pentagon-researchers-test-worst-case-scenario-attack-us-power-grid/152829/?oref=d-channelriver.

90. *Id.*

91. *Id*.

92. *Id.*

93. *Id*.

94. Randy Atkins, *Countering Urban Terrorism in Russia and the United States: Proceedings of a Workshop*, NAT'L ACAD. PRESS (2006), https://www.nap.edu/read/11698/chapter/6.

95. *Id*.

96. Blake Sobczak, *Experts assess damage after first cyberattack on U.S. grid*, E&E NEWS (May 6, 2019), https://www.eenews.net/stories/1060281821.

97. *Id.*

98. *Id.*

III. ANALYSIS

A. Overview

Due to the lack of cybersecurity incidents reported in 2015-2016, FERC explained that cyber-attacks or incidents were not meeting the defined criteria to make those attempts reportable in nature.[99] NERC pointed out that a lack of reportable incidents does not necessarily indicate that there is no cause for concern; lower-level attacks and data collection from hackers could occur but not trigger the requirement to report.[100] Because of this, FERC adopted Order No. 848 to increase reporting requirements and to clarify definitions and boundaries for reporting incidents.[101] Order No. 848's augmentation of reporting requirements is intended to increase inter-agency communication, the degree and type of information collected pertaining to potential cybersecurity grid threats, the awareness and consciousness of risks involving the grid, and ultimately increase national security.[102]

B. Effectiveness

1. Methodology

The main point of Order No. 848 is to increase the reporting requirements for cybersecurity incidents so that there is more information on what types of threats hackers pose and to ultimately protect the BES from harm.[103] To accomplish this, FERC ordered that NERC modify the existing Reliability Standards and develop further protocols consistent with the Order.[104] The increase in mandates also augmented inter-agency communication.[105]

2. Implementation

Following the issuance of Order No. 848, NERC published an Implementation Guide detailing the Reliability Standards to be changed and providing more specific guidelines for mandated reporting.[106] NERC also provided a cyber security incident reporting form, which included categories such as attack vector, functional impact, and level of intrusion, to ensure consistency in their reports.[107] NERC directed the Responsible Entities[108] to "determine what is normal within

99. Order No. 848, *supra* note 12, at P 9.

100. *Id*.

101. *Id.*

102. *Id.* at PP 13, 22-23.

103. Order No. 848, *supra* note 12, at PP 1-4.

104. *Id.* at PP 1-2, 31.

105. *Id.* at P 34.

106. NERC, CYBER SECURITY – INCIDENT REPORTING AND RESPONSE PLANNING IMPLEMENTATION GUIDANCE FOR CIP-008-6, at 4 (2019) [hereinafter NERC Implementation Guide].

107. *Id.* at 43.

108. Responsible Entities include, for example, Standards Developers, Transmission Planners, Reliability Assurers, Market Operators, and other entities that perform reliability functions. NERC's reliability standards are mandatory for Responsible Entities. NERC, RELIABILITY FUNCTIONAL MODEL FUNCTION DEFINITIONS AND

their environment to help scope and define what constitutes 'an attempt to compromise'" the BES, and also to be creative and search for flexible solutions to reduce the burden placed on them.[109] This approach offers a more effective long-term solution to the issue of cybersecurity in the energy sector as a whole, since the Responsible Entities are most able to assess what constitutes "normal" in each of their respective domains.[110]

One potential issue with the language in the aforementioned directive is that it has the potential to undermine the purpose of Order No. 848 entirely, which is to address the lower-level potential threats that the entities are not catching.[111] For example, an entity could determine that a low-level threat is not outside of the range of every day activity. However, after months of low-level data gathering, hackers could use the collected data to launch a strategic, highly-specific attack.[112] The entity, in this hypothetical, would have simply passed on its opportunity to prevent the harmful attack because it deemed an earlier event to be within normal activity levels. Such was the case with the 2015 Ukraine attack.[113] Thus, the language of this directive must be carefully scrutinized to provide viable solution to preventing overly burdensome agency reporting.

3. Risks of the Order

a. Critiques

As noted earlier, during the Notice and Comment period, there were some critiques posed by various agencies and private entities arguing that implementation of the NOPR would unduly burden the agency and divert voluntary reporting resources.[114] For example, while Eversource and Idaho Power admitted that implementation of the proposal could "provide some visibility into the types of threats that [energy providers] face," the augmentation of reporting requirements would "reduce the finite resources that [energy providers] have to monitor and defend their critical infrastructure."[115]

Several comments also addressed the need for Order No. 848 to define an "attempt" to compromise the system and to specify the types of assets the Responsible Entities needed to monitor, rather than promulgating broad demands.[116] These arguments were made in the interest of not overburdening agencies with

RESPONSIBLE ENTITIES VERSION 5.1 (Dec. 12 2018), https://www.nerc.com/pa/Stand/Functional%20Model%20Advisory%20Group%20DL/Functional_Model_V5.1_clean_10082019.pdf.

109. NERC Implementation Guide, *supra* note 106, at 20.

110. *Id.*

111. Order No. 848, *supra* note 12, at P 9.

112. Kim Zetter, *Everything We Know About Ukraine's Power Plant Hack*, WIRED (Jan. 20, 2016), https://www.wired.com/2016/01/everything-we-know-about-ukraines-power-plant-hack/ [hereinafter Zetter, *Everything We Know*].

113. *Id.*

114. Order No. 848, *supra* note 12, at PP 32-34, 44.

115. *Id.* at P 29.

116. *Id.* at P 52.

inefficient, redundant, or unhelpful reports.[117] These critiques are supported by Andrea Matwyshyn in her law review article focused on the shortcomings of the legal system in regards to cybersecurity.[118] Matwyshyn recognizes the severity of a breach of cybersecurity in both the public and private sectors but says that the two major legal paradigms surrounding cybersecurity are insufficient, as they are.[119] Notably, Matwyshyn points out that these paradigms do not address the underlying issues regarding the cause of cyber attacks and can lead to a focus on information sharing rather than paying attention to the actual substance of the obtained information.[120]

Another major critique of Order No. 848 was that it was overly broad and that it would not adequately address the gaps in the reporting of cyber security incidents.[121] For example, an intervenor group, Trade Associations, argued that the broad language of Order No. 848 could actually lead to a reduction in awareness of *significant* cyber threats (i.e., ones that do more than just attempt to compromise ESPs or EACMS).[122]

b. FERC's Direct Response to Critiques

In response to these critiques, FERC pointed out that its purpose was neither to unduly burden agencies and private entities nor to prescribe overly broad mandates, but that it was trying to support NERC's development of adequate and flexible standards for the industry.[123] Further, NERC also indicated that it would work to make sure that the reporting requirements were flexible and not "unduly burdensome" for the affected entities.[124]

4. Benefits of the Order

To truly understand the benefits of the Order, the severity and consequences of a potential, severe blackout must be addressed. Security of the BES is intensely important as each economic sector, making up the critical infrastructure of the nation, relies on having a resilient electric grid.[125] In 2017, Thomas Popik, the Foundation for Resilient Societies' founder and chairman,[126] testified before FERC to detail what exactly a long-term, large-scale blackout would look like in the United States.[127] A long-term and large-scale blackout is one that "[p]ersists

117. *Id.* at P 63.

118. Andrea M. Matwyshyn, *CYBER!*, 2017 BYU L. REV. 1109 (2017).

119. *Id.* at 1124-25.

120. *Id.* at 1128.

121. Order No. 848, *supra* note 12, at P 33.

122. *Id.* at PP 44, 49. The Trade Associations is made up of: American Public Power Association, Electricity Consumers Resource Council and Transmission Access Policy Study Group.

123. *Id*. at P 32.

124. *Id*.

125. Robert Knake, *A Cyberattack on the U.S. Power Grid*, COUNCIL ON FOREIGN RELATIONS (Apr. 2017), https://www.jstor.org/stable/resrep05652.

126. Thomas Popik, *Our Energy Policy*, https://www.ourenergypolicy.org/author/thomaspresilientsocieties-org/.

127. Popik Testimony, *supra* note 18.

longer than the supplies of backup energy necessary for grid restoration" and "[c]overs a geographic area so large that significant outside assistance is impractical."[128]

Luckily, the United States has never experienced a blackout that would meet such criteria, as most of the major blackouts in the United States have been resolved within twenty-four (24) hours.[129] A long-term and large scale blackout could lead to devastating consequences in our nation.[130] Within two (2) minutes of the BES failing, affected nuclear power plants would have to turn on emergency diesel generators since the Nuclear Regulatory Commission (NRC) requires the grid to be stable in order for nuclear plants to operate.[131] This measure is to cool the plants down, not to produce more energy.[132] Sixteen (16) hours into the blackout, most telecommunication functions would be inoperable, with the exception of the few offices that have a seventy-two (72) hour backup fuel supply.[133] Within a few days, vehicles that ran out of fuel would clutter the streets, government services would stop, critical infrastructure would be damaged or destroyed entirely, and human casualties could potentially reach the millions.[134] Additionally, the backup diesel generators at the nuclear plant would likely have run out by the seventh day which would cause the reactor cores to overheat and the spent fuel pools to boil.[135] Without any change in the conditions, by the 30th day, nuclear plants will have become highly radioactive and unsafe for humans to be around.[136] Further, there is a likelihood that some fuel pools would ignite, which could create "plumes of radioactive material over large areas."[137]

Although the United States has not experienced a large-scale, long-term blackout, the consequences from some of the major blackouts in the United States still present a cause for concern.[138] For example, in 2003, the Northeast Blackout left about fifty million (50,000,000) individuals without power.[139] This blackout resulted in four (4) to ten (10) billion dollars in economic loss, even though the majority of this event did not last for more than a day.[140] At large, the United States is estimated to have lost between twenty (20) to fifty-five (55) billion dollars due *specifically* to power outages related to the weather.[141] As a recent example,

128. *Id*. at P 1.

129. *Id.*

130. *Id.*

131. Popik Testimony, *supra* note 18, at P 2.

132. *Id*.

133. *Id.*

134. *Id.* at P 1.

135. Popik Testimony, *supra* note 18, at P 2.

136. *Id.*

137. *Id.*

138. *Id.* at P 1; Knake, *supra* note 125, at 3.

139. Knake, *supra* note 125, at 3.

140. *Id.* at 3; Popik Testimony, *supra* note 18, at 1; Chris Bronk, *Hacks on Gas: Energy, Cyber Security, and U.S. Defense*, STRATEGIC STUDIES INST., US ARMY WAR COLLEGE, at 303 (2015).

141. Salahuddin Qazi, *Power Outage*, Photovoltaics for Disaster Relief and Remote Areas (2017), https://www.sciencedirect.com/topics/engineering/power-outage.

Winter Storm Uri caused ERCOT to order rolling blackouts "to keep the grid from shutting down altogether."[142] To date, costs of Winter Storm Uri are still being calculated; some estimate costs could be as much as $200 billion[143] while it cost dozens of individuals their lives.[144] ERCOT CEO, Bill Magness, spoke out on the matter and explained that the rolling blackouts were necessary "to prevent a widespread blackout that could last months" or longer.[145] Although the United States has not experienced a long-term, large-scale blackout, an event of that severity would almost certainly result in severe economic loss (in the billions) and drastic damage to the critical infrastructure of the country.[146] Protecting the BES is necessary because a successful cyber-terrorist attack on the grid could leave the nation devastated and in shambles.

The severity of a successful attack is precisely why augmenting the reporting requirements is so important; such a move is warranted in spite of critiques for a number of reasons. The majority of the critiques received were concerned with the burdens that the new reporting requirements might cause or concerned that unhelpful data would be reported. FERC essentially conducted a cost-benefit analysis and determined that the increased burden would be worth the potential benefits in this area. Some scholars have concluded that the cost of compliance with the NERC Reliability Standards is questionable, although these conclusions fail to take into account more modern economic trends and technologies.[147] Other analyses take into account the initial responses from Responsible Entities and highlight the acceptance process that comes along with imposing new regulations.[148] The Responsible Entities failed to provide a detailed explanation or quantify costs for compliance regarding the ways in which complying with Order No. 848 would overburden them.[149] Additionally, the cost of the increase in reporting can be budgeted for by grid operators;[150] this cost can be estimated and planned for

142. Jan Wesner Childs, *Why Winter Storm Uri Caused Millions of Power Outages in Texas*, WEATHER CHANNEL (Feb. 16, 2021), https://weather.com/news/news/2021-02-16-why-so-many-power-outages-in-texas-winter-storm.

143. Irina Ivanova, *Texas winter storm could top $200 billion – more than hurricanes Harvey and Ike*, CBS NEWS (Feb. 25, 2021), https://www.cbsnews.com/news/texas-winter-storm-uri-costs/.

144. Reis Thebault, Paulina Firozi & Brittany Shammas, *58 people died in last week's frigid weather. Some of them were just trying to stay warm.*, WASHINGTON POST (Feb. 21, 2021), https://www.washingtonpost.com/nation/2021/02/18/winter-storm-deaths/.

145. Christian Flores, *CEO of ERCOT says rolling outages were necessary to prevent widespread blackout*, CBS AUSTIN (Feb. 17, 2021). https://cbsaustin.com/news/local/ercot-holding-conference-call-on-widespread-outages-affecting-millions-of-texans.

146. Knake, *supra* note 125; Popik Testimony, *supra* note 18; Bronk, *supra* note 140; Qazi, *supra* note 141.

147. William F. Watson, *NERC mandatory reliability standards: A 10-year assessment*, 20 ELEC. J. 9-14 (Feb. 16, 2017).

148. James Stanton, *Where Are We After 10 Years of Bulk Electric System Reliability Standards?*, POWER (Feb. 1, 2017) https://www.powermag.com/where-are-we-after-10-years-of-bulk-electric-system-reliability-standards/.

149. Order No. 848, *supra* note 12, at P 54.

150. NERC, 2019 BUSINESS PLAN AND BUDGET, at 17 (Aug. 8, 2018), https://www.nerc.com/gov/bot/FINANCE/19BusPlanBud/2019%20NERC%20Business%20Plan%20and%20Budget%20-%20Revised%20Final.pdf.

whereas the costs of a significant attack on the grid are completely unknown. The costs for complying with the reliability standards can be passed through to customers on a level basis over time.[151]

Order No. 848 and NERC's Implementation Guide fit into the well-known Swiss Cheese model discussed by James Reason, an author and professor of psychology.[152] Reason describes functional systems to have layers of defenses, barriers, and safeguards to protect the entity in question from various hazards.[153] Safeguards include layers of security that can be provided through utilizing a number of different methods such as data encryption, firewalls, passwords, biometrics, and antivirus.[154] There are, unfortunately, innate holes in those protective technological guards.[155] Those holes often open, shut, and change locations, which can make diagnosing and curing the protective shields' shortcomings rather difficult.[156]

By augmenting the reporting requirements, FERC is effectively trying to address the holes in the protective shields of the BES and to better understand what attackers are looking for, what they are doing, and how to best address those concerns.[157] Although agencies will have more work and procedures to follow, FERC believes that compliance with Order No. 848 does not present agencies with a greater burden than a compromise in the BES would provide.[158] NERC follows the same rationale in its Implementation Guide by encouraging agencies that deal with EACMS and EAPs to change the provided configuration "in favor of architectures that offer layers of safeguards and a defense in depth."[159] This mitigation of risks exemplifies forward and conscious thinking, which should help prevent major large-scale attacks on the grid.

5. Continuing Development

In late 2020, FERC issued a new Notice of Proposed Rulemaking to examine ways to "provid[e] significant cybersecurity benefits for actions taken that exceed the requirements of the CIP Reliability Standards" in order to encourage utility providers to improve and invest in cybersecurity voluntarily; the Cybersecurity Incentives NOPR.[160] Since the CIP Reliability Standards provide a results-based mandate, FERC opined that incentivizing public utility providers to innovate and "to adopt best practices" would help "to protect its own transmission system as

151. *Cybersecurity Incentives, Notice of Proposed Rulemaking,* 173 F.E.R.C. ¶ 61,240, at PP 40–46 (2020).

152. James Reason, *Human Error: Models and Management*, 320 BRITISH MED. J., No. 7237 (Mar. 18, 2000), https://www.jstor.org/stable/25187420.

153. *Id*. at 769.

154. Paul Zandbergen, *System Security: Firewalls, Encryption, Passwords & Biometrics*, STUDY, https://study.com/academy/lesson/systems-security-firewalls-encryption-passwords-biometrics.html.

155. Reason, *supra* note 152.

156. *Id.*

157. Order No. 848, *supra* note 12.

158. *Id.* at P 66.

159. NERC Implementation Guide, *supra* note 106, at 20.

160. Notice of Proposed Rulemaking, *Cybersecurity Incentives*, 173 F.E.R.C. ¶ 61,240, 86 *Fed. Reg.* 8,309 (2021).

well as improve the security of the BES."[161] If the implemented improvements were found to be particularly helpful, they might become mandatory in CIP Reliability Standards later on.[162]

Qualifying for FERC's proposed incentives will not pose an insignificant hurdle; routine improvements and costs associated with CIP Reliability Standard compliance would not make utility companies eligible for FERC's proposed incentives.[163] To qualify for FERC's proposed incentives, the cybersecurity investments must go "above and beyond the requirements of the CIP Reliability Standards, and materially enhance the cybersecurity posture of the Bulk-Power System by enhancing applicant's cybersecurity posture substantially above levels required by the CIP Reliability Standards, to the benefit of ratepayers."[164] FERC took note of its need to establish methods to assess implemented improvements.[165]

FERC wanted to incentivize public utilities to invest in and improve their cybersecurity, largely in response to the COVID-19 pandemic.[166] FERC is acutely aware of the increase in threats and vulnerabilities that come with working from home and the infrastructure necessary to operate the global supply chain.[167] Although there are methods of monitoring cyberthreats in place, FERC recognized their limitations and wanted to induce the implementation of flexible innovations to respond to the ever changing threats the BES faces.[168] It is important to note that the CIP Reliability Standards remain mandatory and effective measures for monitoring and managing cybersecurity threats.[169] However, not all utility providers are required to adhere to the CIP Reliability Standards; the CIP Reliability Standards are mandatory for Responsible Entities[170] to follow.[171] Should the Cybersecurity Incentives NOPR become a final order, it could encourage some providers to voluntarily comply with the CIP Reliability Standards and stimulate cybersecurity improvements within their available means for all utility providers.[172] A final order based on the Cybersecurity Incentives NOPR could also facilitate more efficient and effective response to threats, as creating new Reliability Standards can take months to become operational and enforceable.[173]

161. *Id.* at P 14.

162. *Id*.

163. *Id.* at P 3.

164. *Id.* at PP 1, 3.

165. 173 F.E.R.C. ¶ 61,240, at P 15.

166. *Id.* at P 17.

167. *Id*. *See also Supply Chain Risk Management Reliability Standards*, Order No. 850, 165 F.E.R.C. ¶ 61,020 (2018); Letter Order Accepting Proposed Supply Chain Reliability Standards Mandated by Order No. 850, 174 F.E.R.C. ¶ 61,193 (2021).

168. *Id*.

169. *Id*. at P 18.

170. *See supra* note 108.

171. Order No. 848, *supra* note 12, at P 18.

172. *Id*.

173. *Id*. While the formal commenting process at the Commission is not yet complete as of this writing, comments both for and against are expected based on prior statements of interested parties. *See* https://www.utilitydive.com/news/energy-sector-divided-over-transmission-incentives-for-voluntary-cybersecur/584019/. Any

IV. CONCLUSION

In sum, Order No. 848 was promulgated to augment the mandatory reporting guidelines and delegated to NERC to draft a new Reliability Standard.[174] Although Order No. 848 amended the definitions of several key terms within the cybersecurity sphere, there are still concerns as to whether these changes were specific enough to warrant the change.[175] FERC ultimately adopted the NOPR, in spite of complaints that Order No. 848 would be too burdensome on already-spread-thin reporting entities and that the products of their work might not actually be helpful.[176]

The rationale for FERC's decision can be demonstrated through a number of studies and actual cyber-attacks.[177] These studies indicate that a major blackout in the United States would cost a tremendous amount of money, eat up resources, destroy critical infrastructure, potentially leave the country more vulnerable to terrorism, and even possibly lead to millions of human casualties.[178] While Order No. 848 does create more work for reporting entities, the goal of the Order is to help the energy sector better understand what threats lie in wait, bulk-up their protections of Cyber Assets, understand where their systems are vulnerable, and to preserve the resilience of the grid.[179] Adding additional entities and governmental agencies, such as DHS, into the reporting requirements increases inter-agency communications which help to better understand and minimize national security risks.[180] With potentially catastrophic consequences at stake, the benefits of Order No. 848 outweigh the disadvantages.

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final rule will be noteworthy for how comments opposing the NOPR are discussed with respect to issues regarding the cost benefit analysis of the new regulations.

174. Order No. 848, *supra* note 12, at P 1.

175. *Id.* at PP 9, 63.

176. *Id.* at PP 52, 63.

177. Popik Testimony, *supra* note 18; Zetter, *Inside the Hack of Ukraine's Power Grid*, *supra* note 85; Zetter, *Everything We Know*, *supra* note 112; Knake, *supra* note 125; Bronk, *supra* note 140; Qazi, *supra* note 141.

178. Popik Testimony, *supra* note 18.

179. Order No. 848, *supra* note 12, at PP 20, 32.

180. *The 9/11 Commission Report Final Report of the National Commission on Terrorist Attacks Upon the United States*, NAT'L COMM'N ON TERRORIST ATTACKS UPON THE U.S., https://govinfo.library.unt.edu/911/report/911Report_Exec.htm.

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