Whither the FERC?

Overcoming the Existential Threat to Its Magic Pricing Formula through Prudent Regulation

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Abbreviations

ARC — Aggregated Retail Customers
BUR — Bottom Up Review
DER — Distributed Energy Resource
CONE — Cost of New Entry
DR — Demand response
DRR — Demand Response Resources
DSPP — Distribution System Platform Provider
Distop — Distribution Operator
EIS — Environmental Impact Statement
FERC — Federal Energy Regulatory Commission
FPA — Federal Power Act
FPC — Federal Power Commission
GAO — U. S. General Accountability Office
ISO — Independent System Operator
IRP — Integrated Resource Plan
ISO-NE — Independent System Operator – New England
LCAPP — Long-term Capacity Agreement and Pilot Program
LCOE — Levelized Cost of Energy
LMP — Locational Marginal Price
LSE — Load Serving Entity
MC — Marginal Cost
MECC — Marginal Expected Curtailment Cost
MISO — Midwest Independent System Operator
MOPR — Must Offer Pricing Rule
MW — Megawatt
MWH — Megawatt-hour
NGA — Natural Gas Act
NMPC — Niagara Mohawk Power Corporation
NOPR — Notice of Proposed Rulemaking
NYISO — New York Independent System Operator
ORDC — Operating Reserve Demand Curve
ORTP — Offer Review Trigger Price
PJM — Pennsylvania-Jersey-Maryland Interconnection
PUHCA — Public Utility Holding Company Act
PURPA — Public Utility Regulatory Policies Act
RPM — Reliability Pricing Model
RTO — Regional Transmission Organization
SMO — Southeast Market Pipelines
TPUC — Texas Public Utility Commission
VoLL — Value of Loss Load

Author Biography

Dr. Carl Pechman is the Director of the National Regulatory Research Institute. His career in regulation began as an undergraduate, assisting in the econometric modeling of energy demand. He served as the supervisor of Energy and Environmental Economics at the New York Public Service Commission. In that role, he was responsible for developing and implementing methods of estimating avoided costs, as well as leading commission processes that resulted in the restructuring of the New York electric system. As the founder and president of Power Economics, Inc., he supported the speaker of the California State Assembly to navigate and resolve the California energy crisis. He served as an expert witness for the California parties in efforts to recover excessive profits from entities that exercised market power during the crisis. Dr. Pechman led the review and the public release (in testimony before FERC) of the Enron trader tapes. During that time, he was also actively involved in the analysis and development of capacity markets. Dr. Pechman joined FERC staff as an economist, with the desire to avoid market meltdowns through robust market design. He invented the cost-effectiveness test, relied upon by the Supreme Court in its affirmation of FERC's Order 745 in *FERC v. EPSA*. While at FERC, he was detailed at the request of the Department of Energy to support the development of the Quadrennial Energy Review. In 2018, Dr. Pechman became the director of NRRI. Since then, he has initiated the Regulatory Training Initiative, a program for training regulatory staff and stakeholders on the theory and practice of regulation and has provided support to the Puerto Rico Energy Bureau on developing a new regulatory regime for the Puerto Rico electric system.

Dr. Pechman is the author of *Regulating Power: The Economics of Electricity in the Information Age* (Kluwer Academic Publishers, 1993), which developed the following concepts: models as the language of regulation, the ability to specify market structure as a source of market power, the importance of locational-based generation reserve requirements, and strategies for harmonizing state and federal electricity regulation.

Dr. Pechman received his BS, MS, and PhD from Cornell University.

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Cover Photo: FERC Facebook Page

Preface

The expert report submitted with the April 14, 2020 petition by the New England Ratepayers Association (NERA) for the Federal Energy Regulatory Commission (FERC) to scuttle state net energy metering programs had an interesting point. NERA's expert Ashley Brown's underlying premise, that there was much that FERC needed to consider in its consumer protection role and relationship with the states while navigating the decarbonization of the electric sector, was a good one. Unfortunately, the deliberative process used to evaluate the complaint of necessity focused on its legal merits and analytical errors, and not on its provocative ideas on the regulatory role of FERC. As a consequence, ideas on how FERC could improve its regulatory performance, including its coordination with the states, were off the table. One aim of this paper is to put that discussion back on the table by addressing the existential threat to FERC's method of price making (which I call its "magic pricing formula") and suggesting ways in which FERC can move beyond "magic" and toward a more reasoned approach to determine wholesale prices in an environment with a greater focus on decarbonization and greater harmony with the states.

The issue is complex, with a good deal of history that frames the way FERC makes prices. This paper tries to unpeel the onion. It is long and detailed. It is a research monograph prepared for the National Regulatory Research Institute's research paper series, which has been ongoing since 1976. Although the paper presents policy recommendations, it is not strictly a policy paper. The role of NRRI is to present its research and ideas to its members, the nation's public utility commissions, and to the broader regulatory community. Thus, this paper should be viewed for what it is, a vehicle for educating and fostering conversation in the regulatory community and proposing policy options to resolve the issues it identifies.

The author is responsible for all errors and the views expressed herein are solely the author's. That said, NRRI appreciates any comment, identification of errors or omissions, and more complete descriptions of facts and concepts presented. To foster discussion, NRRI has established a site (https://bit.ly/whitherferc) for additions, comments, and discussion. The report highlights the need to start that conversation. To participate in that conversation, visit this URL.

During my time testifying as an expert witness, judges have asked whether my testimony was as a fact witness or an expert witness. Often, the answer was both. This paper is the culmination of my work on the theory and practice of the economics of electricity in a regulatory environment. Many of the processes and proceeding discussed in this paper are ones in which I was involved.

Executive Summary

In reflecting on his chairmanship, Neil Chatterjee opined that "(t)he days of FERC being referred to as an obscure agency are over."[1] By regulating our nation's organized markets for wholesale electric and natural gas, FERC plays a critical role in the health of the U.S. economy. It will also play a vital role in the success or failure of efforts to reduce greenhouse gas emissions by crafting a regulatory environment in which various options will either flourish or wither and die. As Commissioner Chatterjee further reflected in that interview, "(w)here appropriate throughout my tenure, I wanted to do something appropriate about carbon mitigation." FERC's limitations on its approach to carbon mitigation are largely self-imposed. It is time for FERC to reconsider what its appropriate role ought to be with respect to carbon mitigation and to begin a critical dialogue with its stakeholders.

Central to FERC's role is its consumer protection mandate to ensure that wholesale electricity rates are "just and reasonable." It does this by regulating the rates, operations, and design of the organized markets administered by the nation's Independent System Operators (ISOs). The electric markets that FERC regulates provide wholesale electric service to 66 percent of total U.S. load. The three Northeast ISOs: the New York ISO (NYISO); ISO-New England (ISO-NE); and the Pennsylvania, Jersey, Maryland Interchange (PJM) comprise 41 percent of total ISO load and 27 percent of total U.S. load.[2]

FERC has a special relationship with the three Northeastern ISOs, dating back to before electric restructuring in the 1990s. Each of these ISOs had its operational and market genesis in "tight" power pools[3] that were transformed into markets for power. Each of these serves a region in which vertically integrated utilities have divested their rate-based generation and sold it to entities that receive remuneration through the market. In these areas, retail service is provided either through regulated incumbent distribution utilities or merchant "load-serving entities" (LSEs). FERC's role in this relationship is to regulate the process of price making used by the ISOs. It does so to satisfy its consumer protection mandate under the Federal Power Act that prices be "just and reasonable."

A neglected question in the transformation from cost-of-service rates to prices based on markets is how to structure the payment to generators for their capacity, i.e., how to create capacity markets. FERC has always played catch-up in the design of mechanisms to provide generators with revenue adequacy and price signals for entry and exit. Its response has been to rely on capacity markets. Although ISOs began operating in the late 1990s, it was not until 2003-04 that they adopted formal capacity markets. The time for the current design of those markets has already passed, as those markets were designed for a different situation than we find ourselves in today. It is time to recognize that alternatives to capacity markets are needed.

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1 Morehouse, C. "'The days of FERC being referred to as an obscure agency are over': Chatterjee reflects on chairmanship," *Utility Dive*, November 9, 2020, https://www.utilitydive.com/news/the-days-of-ferc-being-referred-to-as-an-obscure-agency-are-over-chatter/588610/.

2 NERC 2019 Electricity Supply Demand (ES&D) – Released December 2019. Total Net Energy for Load (NEL) represents actual data for 2018. NEL data for CAISO includes some non-CAISO entities and a small portion of Mexico, http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx.

3 Power pools were organizations that coordinated transactions between utilities. Tight power pools, had clearly articulated rules that governed the pricing of those transactions and dispatch centers that coordinated them. Power Pools were transformed into ISOs.

FERC relies on a "magic pricing formula" to fulfill its role in customer protection; particularly, for the three Northeast ISOs. The term "magic formula" comes from John Landis' Report on Regulatory Agencies to the President-Elect (Kennedy).[4] In his report, Landis uses this term to describe FERC's predecessor, the Federal Power Commission's (FPC) efforts to develop a single formula for regulating the field price of natural gas. Unfortunately, determining the field price of natural gas (like the emergent challenges in the electric industry today) was a complex problem that could not be solved with a single formula. Recognizing this, FERC's ultimate solution, with legislative support, was to restructure the entire approach to the regulation of wholesale markets for natural gas, moving from prices determined by cost-of-service methods to a regime of market-based pricing.

This research study addresses the emerging issue of how FERC can regulate the complex electric market, which has a growing mandate to decarbonize, is increasingly reliant on renewable energy, and must accommodate the changing role of the customer from "load" to prosumer. These factors are new, and it is time for FERC to take a hard look at how to embrace them. The key question, then, is whether FERC's reliance on the magic pricing formula artificially (and possibly incorrectly) limits the regulatory choices that it considers as options when thinking about the future, and what might replace that formula. The answer will be relevant to all the markets regulated by FERC, not just the Northeastern markets.

The central thesis of this study is that FERC's magic formula for wholesale electric price-making and capital cost recovery is increasingly invalid as a proxy for just and reasonable rates. The formula is based on the rich literature on the economic theory of peak load pricing beginning in the 1940s. The "Peaker Method," as it is called, is the practical implementation of that theory, used to estimate "avoided costs" (in compliance with the Public Utility Regulatory Policies Act of 1978) to provide a pricing framework for non-utility generation. FERC adopted this approach to pricing during the transformation of the electric regulatory structure from a cost-of-service basis to a market basis. At that time, adopting the theory behind the Peaker Method was reasonable, but it is now increasingly less so, given the revolutionary change in options for providing customers with electric service and the need to decarbonize. Ironically, avoided cost contracts supported the early development of many types of the renewables that now pose an existential threat to the future role of the Peaker Method in the regulation of the markets. The increasing prevalence of zero marginal cost renewable generation, combined with the changing role of the customer, turns the underlying theory on its head and creates this threat to FERC's magic pricing formula, as it renders it unsustainable.

The Peaker Method yields a two-part pricing formulation: energy markets and capacity markets. Energy markets involve the real-time coordination of generation resources to meet customers' instantaneous demand. These markets are fairly straight forward extensions (albeit technically complex) of methods developed by vertically integrated utilities. The key change is in the treatment of capacity. Historically utilities were vertically integrated, owning all of the levels of the supply chain—generation, transmission, and distribution. These utilities recovered the costs of investments made to meet customer demand through regulated rates collected from customers. Now, increasingly, merchant generators that provide generation to the grid rely on market prices for recovering their investment and making a profit.

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4 Landis, John, "Report on Regulatory Agencies to the President-Elect," December 1960, https://ratical.org/corporations/linkscopy/LandisRpt1960.pdf. John Landis, former dean of the Harvard Law School, founding commissioner and second chairman of the Securities and Exchange Commission, and Civil Aeronautics board chair, authored *The Administrative Process,* which informed the development of the Administrative Procedures Act, Yale University Press, 1938.

The theory underlying the Peaker Method focuses on how to price electricity to recover the capital costs of generation. Generators earn infra-marginal rents when their marginal cost of producing power is less than the market price. It turns out that in an optimal resource mix,[5] with generators receiving compensation based on market prices, there will be a revenue shortfall equal to the cost of a peaker. The only reason to build a peaker is to support electric system reliability, and, as the most expensive resource to operate on the system, there are no inframarginal rents to amortize its capital costs. This provides the theoretical basis for what has been called the missing money problem.[6] It also provides the rationale in the Peaker Method for developing mechanisms for compensating generators for the capital costs of system resources.

As described in this study, capacity markets require continuous administrative intervention to create prices that comport with FERC's market expectations. These expectations are based on an administrative structure that was derived from the economic theory of peak load pricing,[7] which, although brilliant for its time, is becoming increasingly obsolete.

The capacity markets are auction-based markets that have a range of auction periodicities from monthly auctions to fulfill more immediate capacity obligations to annual auctions in which capacity is procured three years ahead of when it is needed. In these capacity auctions, resource offers are gauged against a demand curve, administered by the FERC, and not a market-based evaluation, to determine the price paid for capacity and the amount of capacity acquired. Capacity markets are an administratively set pricing mechanism, and an almost incomprehensibly complicated one at that. It is hard to imagine that any cost-of-service method could be more complex and opaque than the capacity markets.

The administrative procedures overseen by FERC and mis-classified as competitive markets are extremely problematic. Capacity markets "have proven themselves incapable of: meeting load-serving entities' needs for diverse resource portfolios; enabling states' efforts to pursue policy goals; satisfying generators' need for stable revenues; or ensuring resource adequacy."[8] As a consequence, FERC has had to resuscitate these markets by limiting the participation of renewable resources. This has been accomplished by imposing rules that create a market fiction that requires market participants to provide offers at or above administratively determined levels, while at the same time undermining state policy that financially supports resource investments. As FERC explained in its December 2019 order on PJM's Minimum Price Offer Rule (MOPR), "…our statutory mandate requires the Commission to intervene "when subsidized [resources] supported by one state's or locality's policies has the effect of disrupting the competitive price signals that PJM's [capacity auction] is designed to produce, and that PJM as a whole, including

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5 The optimal capacity mix is determined by minimizing the cost of providing service recognizing the tradeoff between capital and operating costs.

6 The missing money problem is a shortfall of revenues required to cover the capital investment in generation. Advocates for generator owners argue that this problem exists because of administrative price caps, which are imposed on markets to thwart the unfettered exercise of market power during periods of scarcity. The term was introduced by: Shanker, R. "Comments on Standard Market Design: Resource Adequacy Requirement." Federal Energy Regulatory Commission, Docket RM01-12-000. (2003), p. 3, http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9619272.

7 Marcel Boiteux was the first to develop this theory in 1949. See: Boiteux, Marcel P. «La tarification des demandes en pointe: Application de la théorie de la vente au coût marginal», 1949, *Revue générale de l'électricité.*

8 Morrison, J., "Capacity Markets: A Path Back to Resource Adequacy," *Energy Law Journal*, Vol 37, No. 1 (2016), p. 1, 18-1-60-Morrison_FINAL.pdf (eba-net.org).

other states, rely on to attract sufficient capacity."[9]

Historically, there has been a bright line between state and federal electricity regulation. FERC regulates the wholesale market, initially inter-utility sales, also called sales for resale; and now sophisticated power markets operated by ISOs. In that earlier formulation, customers were load who purchased their power from utilities that participated in the wholesale markets. State-regulated utilities provided retail service to the customers who used the power. Customers were at the end of the line of a one-way flow of power that started with generation, was transported over transmission lines, and distributed by local utilities. Now, the electric market is becoming more complex, with customers increasingly becoming active participants in electric markets as prosumers that both buy electricity and sell services (either demand response or electricity) back to the system. This blurs the jurisdictional line between wholesale and retail sales and makes the authority of state regulatory commissions and FERC ambiguous.

The result of FERC's focus on creating an appropriate price signal has displaced its statutory role of protecting consumers and the public interest and has led to an unprecedented split between the states and FERC. It is evident that the changes in electric generation and the new smart, but disruptive, role of consumers pose an existential threat to the magic pricing formula and, perhaps, to FERC's future role in regulating electric markets. Renewable generation, which essentially has zero marginal costs, will wreak havoc on the energy markets' ability to play their role in supporting investment in needed generation. Inframarginal rents for amortizing capacity investment will decline. The capacity markets will need to pick up the slack. This will be difficult when they are already on life support. Indeed, there is no reason to be optimistic that the capacity markets can be modified to successfully support financing the capital requirements of decarbonization.[10] Actions such as FERC's recent PJM MOPR are designed to resuscitate those markets. Creating appropriate price signals increases payments to generators at the cost to consumers and the economies served by the ISOs. Goggin and Gramlich estimate that the cost of subjecting state supported generation to PJM's MOPR could reach $5.7 billion a year or a 60 percent increase in cost.[11] It is, therefore, not surprising that FERC's actions are prompting states to consider ordering their utilities to abandon FERC regulated markets, effectively backtracking on unbundling and re-establishing the power procurement role of utilities. It is time to determine whether the current magic pricing formula is up to the job. And, if not, what the alternatives are and whether it would be more advantageous to have a portfolio of market mechanisms rather than a single magic pricing.

The prudence standard is one of the primary tools used by regulators to judge the reasonableness of utility actions. It provides the gateway for cost recovery of utility expenditures. It is based on the nature of the utility's deliberative process, not the final outcome of its decision. The prudence standard revolves around the question of whether an action is reasonable given the facts that are known and knowable at the time that the decision is made. Prudence is a well-accepted standard for deliberation and should be used as a standard for evaluating regulatory behavior as well. Because FERC's own deliberative processes are not based on what is known and knowable, they effectively limit the nature of the information available for deliberation. It is time for FERC to adopt a prudent approach to regulation.

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9 *Calpine Corp. v. PJM Interconnection, L.L.C.,* 169 FERC ¶ 61,239 (2019) at p. 68 ("PJM MOPR") citing: 2011 MOPR Rehearing Order, 137 FERC ¶ 61,145 at P 3; see supra note 23.

10 Decarbonization will be very capital intensive, renewables are pure capital investments, with minimal operating costs, and Carbon Capture and Storage (CCS) is a capital-intensive technology.

11 Goggin, M. and Gramlich, R. "Consumer Impacts of FERC Interference with State Polices: An Analysis of the PJM Region," *Grid Strategies,* August 2019, p. 2, https://gridprogress.files.wordpress.com/2019/08/consumer-impacts-of-ferc-interference-with-state-policies-an-analysis-of-the-pjm-region.pdf.

FERC's principal objective, as defined by its mission statement, is "economic efficiency." One only needs to look at the structure of different capacity markets to recognize that FERC has not relied upon what is known and knowable in its pursuit of efficiency. The capacity markets in ISO-NE, the NYISO, and PJM – Interconnection are all very different. How can a regime in which these three ISOs have such different markets designed to meet the same objectives all be economically efficient? Geographic differences do not provide the answer to how and why these markets are different. The differences are based on the stakeholder processes within the ISOs. Those processes frame the information FERC uses for its decision making, which the courts have characterized as passive. The correct path for FERC to take is active and prudent regulation in coordination with the states to achieve the objective of efficiency. It will need to do so in the future to fulfill its consumer protection role, while playing an active role in guiding the decarbonization of the electric sector.

Prudent federal regulation requires coordination with the states. Underlying the notion of economic efficiency is coherence. The wholesale electric markets cannot be efficient if they do not recognize and coordinate with state policies. Those policies represent the interests of the citizens of those states. Those citizens are also the consumers that FERC is charged with protecting. It is now widely recognized that the FERC has recently abandoned its earlier efforts to coordinate with the states. Indeed, FERC's recent actions thwart any states' ability to regulate utilities in compliance with its state policies. Given these policies, it is no wonder that many of these states feel frustrated, as their efforts to maintain reliability and to decarbonize are increasingly interfered with and seemingly assaulted by an agency whose powers were developed to support state regulation, rather than to restrict state regulatory and policy goals. FERC needs to reinstate and readopt its past efforts to coordinate with the states. This change will be vital to it successfully fulfilling its mission.

For those who follow energy policy and are working to promote a clean energy future, the elephant in the room for FERC is its role in the U.S. efforts to decarbonize. FERC must identify and remove self-imposed constraints on efforts to decarbonize. This is largely a function of the nature of FERC's decision-making processes, in which it responds to petitions and complaints rather than setting a regulatory agenda. FERC's caution, often characterized as deliberation, is not an adequate excuse for avoiding innovation.

At different times in the life of an agency, it needs to pause to take stock. FERC's predecessor, the FPC, did so with the National Power Survey. The New York Public Service Commission did so with a "self-assessment" in the 1990s at the dawn of restructuring the state's electric markets. Many federal agencies maintain situational awareness of the factors influencing their approach to governing change. To address that challenge, they prepare quadrennial reviews that articulate the agency's mission and delineate plans to achieve that mission. It is time for FERC to follow suit and also take stock to clarify its mission with respect to consumer protection and decarbonization; to rationalize its relationship with the states; and, ultimately, to lead rather than passively follow. FERC has an excellent and dedicated staff. The opportunity for leadership and a new approach by FERC couldn't be more clear, as a failure to adapt and modernize its regulatory model will otherwise have long-term deleterious effects for the process of decarbonization, the future of the electric grid, and the U.S. economy.

Recommendations

Given the need to decarbonize, the growing role of electrification, the critical frailty of FERC's magic pricing formula, and the growing and substantial evidence that the current approach will not meet the challenge it faces, it is time for FERC to consider alternatives. To facilitate FERC's efforts to develop a new regulatory paradigm that will both be truly efficient and will enable the decarbonization of the United States, the following actions are recommended:

1. Create an expert panel on emerging technologies to analyze how current market structures limit the adoption of new technologies and propose alternative market designs that enhance innovation.
2. Evaluate the way that the Commission receives information and determine what enhancements are necessary to enable prudent regulation.
3. Audit the FERC approved and regulated stakeholder governance structure to determine whether it yields efficient results or is an impediment to decarbonization and customer protection.
4. Evaluate the efficacy of capacity markets in compliance with the recommendations made by the U.S. Government Accountability Office.
5. Collaborate with the U.S. Department of Energy to prepare a National Power Survey that maps out the steps required to decarbonize the electric grid including the role of transmission (both new investment and more efficient use of existing infrastructure).
6. Initiate a Quadrennial Regulatory Review process focused on FERC's role in implementing decarbonization policy, customer protection and environmental justice.
7. Create an economics office.
8. Create a stakeholder ombudsman office.
9. Review current management practices to determine if they inhibit regulatory and market innovation, including assessing whether FERC staff is appropriately trained, and whether its culture supports its role as a consumer protection agency.
10. Initiate an open dialogue on the role of carbon and the implications of greenhouse gas reductions on FERC's regulatory scope.
11. Explore methods for working with the states to enhance the efficient transformation of the electric markets to reduce greenhouse gasses.
12. Prepare environmental impact statements on major electric market policy actions that affect the choice of resources used to meet customer demands.
13. Establish an ongoing process and dialogue to investigate market design options that can address methods of decarbonization that assure just and reasonable rates, as well as revenue adequacy for resources supplying the market.

I. Introduction

The New York Times characterized the Federal Energy Regulatory Commission (FERC) as "the most powerful agency that no one knows about."[12] As an economic regulator, FERC oversees the nation's wholesale electric and natural gas markets, and sets the rates for interstate oil pipelines (including the proposed expansion of the Keystone XL Pipeline).[13] It regulates sellers of transmission service and entities that operate wholesale markets and entities that sell at wholesale. It will be a key agency in determining the success of efforts to decarbonize the American economy.

FERC has relied on what is characterized in this paper as a "magic pricing formula" to fulfill its role regulating wholesale electric markets. That formula, called the Peaker Method, has its origin in the engineering-economic literature of the late 1940s through 1980s. This magic pricing formula frames the structure of the wholesale power markets that FERC regulates. The implementation of this formula provides the basis for FERC to meet its consumer protection mandate. Understanding the history and details of this formula provides insight into why that formula is now facing an existential threat because of the proliferation of competitively priced zero marginal cost renewable generation, combined with the animated load that now participates in the operation of the system. This is not just a technical issue, it goes to the heart of FERC's role in decarbonizing the power sector.

FERC, like the entire electric industry, is at a "strategic inflection point."[14] The world of electricity continues to change dramatically, and FERC must change as well to address this development. As the historian of electric technology, Julie Cohn, points out, "Power systems are, by nature, instruments of transformation."[15] Electricity is now viewed as a critical pillar in efforts to decarbonize the U.S. economy. There is growing interest in electrification as a necessary foundation for a decarbonized society. The imperative to reduce carbon emissions is real. Decarbonization has been embraced by 30 states, Washington, D.C., and three territories that have adopted a renewable portfolio standard,[16] and also by a significant segment of the electric utility industry itself. Renewable generation is now available at prices increasingly competitive with traditional forms of generation.[17] Further, states such as New York and Illinois have developed subsidies (zero emission credits) for nuclear to maintain this zero carbon (and also zero marginal cost) resource as part of the overall generation fleet. The role of the customer is also changing — from what was euphemistically called "load"[18] or ratepayers, to that of "prosumers,"[19] who not only consume electricity, but also participate in its production (e.g., through the use of photovoltaics) and its control (e.g., via demand response).

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12 Protess, B., and De La Merced, M.J., "FERC Takes Aim at Wall Street," quoting Tyson Slocum of Public Citizen. November 1, 2012, https://dealbook.nytimes.com/2012/11/01/ferc-takes-aim-at-wall-street/.

13 As an environmental regulator, FERC has siting and oversight responsibility for LNG import and export terminals, natural gas pipelines, and issues licenses for new and existing non-federal hydroelectric electric facilities. FERC's direct jurisdiction over environmental matters is limited; however, as will be discussed in the paper, the environmental impact of its pricing decisions are significant.

14 U.S. Department of Energy, *Quadrennial Energy Report: Energy Transmission, Storage, and Distribution Infrastructure,* April 2015, p. S-14, https://www.energy.gov/sites/prod/files/2015/07/f24/QER%20Full%20Report_TS%26D%20April%202015_0.pdf.

15 Julie Cohn, "Data, Power, and Conservation: The Early Turn to Information Technologies to Manage Energy Resources," *Information & Culture: A Journal of History,* Vol. 52, No. 3, 2017, p. 334.

16 https://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.

17 Lazard, "Levelized Cost of Energy and Levelized Cost of Storage – 2020," Oct. 19, 2020, https://www.lazard.com/perspective/lcoe2020.

18 Load is the level of customer demand. The term can be used in two ways, either as a measure of the instantaneous level of demand in MWs or the aggregation of demand over time (MWhs).

19 The word "prosumer" was introduced by Alvin Toffler in his book, *The Third Wave* (1981), to describe the merging of the roles of consumers and producers in the third wave -information age (agriculture was the first wave and industrialization was the second wave).

The flow of electricity is changing from a one-way flow from the generator to consumer to a two-way flow, where the consumer injects power back into the market. This new role requires a rethinking of the way FERC—and state public utility commissions—manage the regulatory process; specifically, how they deal with price making at the heart of electricity markets.

In its economic role, FERC's primary legislative mandate is to ensure that prices for the energy sold by the entities that it regulates are just and reasonable.[20] The concept of a just price is an ancient notion first introduced by Aristotle, further developed in the Middle Ages by St. Thomas Aquinas, and memorialized in the Supreme Court's 1876 decision in *Munn v. Illinois*. *Munn* found that by engaging in business that affects the public, a person impliedly consents to reasonable regulation. As a consequence, it is in the power of state and federal legislatures to establish price regulation of entities "affected with a public interest."[21]

The way in which FERC exercises its responsibility over prices will play a large role in determining the future of the electric industry and its path to decarbonization. Although FERC has begun exploring its role in resilience, it has done very little for decarbonization. In this paper, I ask why it is prudent for FERC to ask the question about its role with respect to resilience but not to do so with respect to controlling the carbon emissions associated with climate change that drive the need for investment in resiliency. Jon Wellinghoff, the former FERC chairman, warns that decarbonization, "if done under the status quo, could be prohibitively expensive to implement using policies and practices meant for a pre-digital age."[22]

John Landis' ''Report on Regulatory Agencies to President-Elect (Kennedy)"[23] provides the genesis of the term magic pricing formula. In that report, he found that the Federal Power Commission (the FPC — FERC's predecessor), "without question represents the outstanding example in the federal government of the breakdown of the administrative process. The complexity of its problems is no answer to its more than patent failures." Landis's concern, based on issues with the efficacy of the FPC's regulation of the field price of natural gas in the 1950s is that the Commission, "may have hoped that some magic formula would…relieve it of the necessity for independent courageous action."[24] That approach was a single pricing formula for establishing the field price of natural gas, a task that history proved did not lend itself to a single formula. Now, once again, FERC is relying on a magic pricing formula for its oversight of power markets and to relieve it from an exploration of alternative electric market designs.

This paper explains how FERC adopted its magic pricing formula to meet its obligation to protect customers by assuring just and reasonable rates. It describes how the application of this pricing formula has led to the "missing

20 https://www.loc.gov/law/help/statutes-at-large/66th-congress/session-2/c66s2ch285.pdf.

21 The first usage of affected with the public interest was made by Lord Hale, the Lord Chief Justice of England in his 1670 treatise on ports in *De Portibus Maris.* "If the king or subject have a public wharf unto which all persons that come to that port must come as for the purpose to unlade or lade their goods, because they are the wharfs only licensed by the queen, … there cannot be undertaken arbitrary and excessive duties or cranage, wharfage, pesage (fee for weighing), and so forth, neither can they be enhanced to an immoderate rate, but the duties must be reasonable and moderate … For now the wharf and crane and other convenience are affected with a public interest."

22 Wellinghoff, J. "Decarbonizing Wholesale Energy Services," *The Electricity Journal,* Vol. 32. Issue 7, 2019, p.1.

23 John Landis, former dean of the Harvard Law School, founding commissioner and second chairman of the Securities and Exchange Commission, and Civil Aeronautics Board chair, authored The Administrative Process, which informed the development of the Administrative Procedures Act (Yale University Press, 1938).

24 Landis, John, "Report on Regulatory Agencies to the President-Elect" December 1960, https://ratical.org/corporations/linkscopy/LandisRpt1960.pdf.

money" problem.[25] As described later, although once a relevant tool, this pricing formula, based on the "Peaker Method," is becoming obsolete due to the industry's technological revolution, environmental and climate concerns, and changing consumer behaviors. Currently, in an attempt to resuscitate a failing market, FERC has hampered state energy policy.

In addition, this paper makes the case that FERC is not prepared to guide the electric industry as it navigates through this strategic inflection point. Given the complexity of the challenges facing the electric and gas industries today, it is time to ask, "Whither FERC?" and "Can it do better?" Is FERC's statutory role appropriately evolving in the two industries (gas and electric) that have seen unprecedented change during the last decade? FERC has an excellent, dedicated staff who are capable of navigating the path to a decarbonized future. This paper presents suggestions on how they can help accomplish this goal.

FERC needs to find a new paradigm to help it fulfill its customer protection role as the electric market is decarbonized. This paper provides a roadmap for doing so. More importantly, to fulfill its mission in a coherent manner requires that FERC coordinate with state public utility commissions (PUCs),[26] municipal utilities and cooperatives. The paper also introduces the concept of prudent regulation as a guide for evaluating FERC actions. And, importantly, it describes how FERC can fulfill its role as a prudent regulator as it transforms its pricing formula to meet the needs of decarbonizing the power sector.

II. FERC is a Consumer Protection Agency

FERC's role as a consumer protection agency is important, because, although FERC has a duty to ensure that consumers are protected from aggressive pricing and to ensure adequate energy supply, it has not fulfilled its mandate of consumer protection. Importantly, there is no culture of consumer protection within the agency. While serving as an economist at FERC, I had many jaw-dropping conversations in which I was told that "we" were not a consumer agency, that we protect market efficiency. I could never understand how administering the mechanisms of price making had priority over protecting the consumers served by FERC regulated entities. This section will explain the nature of FERC's consumer protection responsibilities. The next section will explain how that responsibility has shifted from the protecting consumers to protecting markets.

FERC's importance has grown from its origin in 1920 as the Federal Power Commission (FPC), an agency created to coordinate federal hydroelectric development, to a powerful economic and environmental regulator. The FPC's (now FERC's) authority was expanded significantly as a consequence of New Deal legislation (the Federal Power Act of 1935 and the Natural Gas Act of 1938) that turned it from a dam development agency to one with a statutorily narrow scope, the regulation of wholesale markets,[27] which could have a large effect on all Americans. The FPC

25 The missing money problem is a shortfall of revenues required to cover the capital investment in generation. Advocates for generator owners argue that this problem exists because of administrative price caps, which are imposed on markets to thwart the unfettered exercise of market power during periods of scarcity. The term was introduced by: Shanker, R., "Comments on Standard Market Design: Resource Adequacy Requirement," Federal Energy Regulatory Commission, Docket RM01-12-000. (2003), p. 3, http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=9619272.

26 Also referred to as public service commissions.

27 FERC also has authority for pricing transmission services. Although important to the wholesale electric markets, transmission pricing can be seen as influencing but largely independent of the pricing of electricity and is therefore not discussed in the paper.

morphed into FERC as a result of the Department of Energy Organization Act of 1977.[28]

In the 1930s, the electric industry structure was controlled by 13 holding companies that owned hundreds of state-regulated, vertically integrated, investor-owned utilities. By 1932, about 49 percent of the investor-owned utility industry was controlled by three super holding companies: the Electric Bond and Share (formed by General Electric); the Insull Empire; and the J.P. Morgan-sponsored United Corporation.[29] This structure thwarted the effective regulation of public utilities, because state PUCs lacked the authority either to obtain underlying cost information or to regulate prices in interstate commerce. President Franklin Roosevelt warned, "No government effort can be expected to carry out effective, continuous and intricate regulation of the kind of private empires within the Nation which the holding company device has proven capable of creating."[30] As Bonbright and Means observed, "(T)he regulation of the operating company must necessarily be ineffective as long as its great master, the holding company, remains free from control by a public service commission."[31] Their diagnosis of the mechanism for control was, "Through the use of the service charge, it (the holding company) has enabled the stockholders of the holding company to 'milk' the operating companies by extortionate charges for services and for commodities, which must be paid for by the consuming public in high rates."[32]

There were two legislative responses to holding company monopoly abuse. The first was the Public Utility Holding Company Act of 1935 (PUHCA), which created limitations on utility ownership and empowered the newly formed Securities and Exchange Commission to oversee the ownership and financial structure of the electric utility industry.[33] The second was the Federal Power Act (FPA), of 1935,[34] which sought to fill in the regulatory gap in state regulation by empowering the FPC to regulate prices for wholesale power and transmission transactions. The basic legislative standard was the requirement that prices be just and reasonable.

The Supreme Court has found that a fundamental purpose of FERC's legislative authority under the FPA[35] "is to protect power consumers against excessive prices."[36] The FPC did so in a variety of ways. It directly regulated prices based upon cost-of-service, resulting in prices based upon those costs plus the opportunity to earn an allowed rate of return on investment. The FPC made it possible for states to get the information they needed to regulate effectively. It collected the information under its own jurisdiction, then made that information public. This information was necessary to protect customers and provide them with a complete, permanent, and effective bond of protection

28 https://www.energy.gov/sites/prod/files/2017/10/f38/DOE%20Organization%20Act%20in%20U.S.C..pdf

29 Hawes, D.W. Holding Companies. Release no 3. Clark Boardman Company, 1987.

30 Twentieth Century Fund, *Electric Power and Government Policy,* Lord Baltimore Press. 1948, p. 347.

31 Bonbright and Means, p. 149.

32 Bonbright and Means, p.154.

33 PUHCA was repealed on February 8, 2006, as part of The Energy Policy Act of 2005.

34 49 Stat. 803

35 The NGA mirrored the requirement that prices be just and reasonable. The PUHCA, administered by the Security and Exchange Commission, created a regulatory structure limiting the ownership, financing, and business activities of holding companies that owned gas or electric utilities. For detail on the subject, and on how holding company structures and activities have changed since PUHCA's repeal, see Scott Hempling, *Regulating Mergers and Acquisitions of U.S. Electric Utilities* (2020).

36 *Pennsylvania Water & Power Co. v. Federal Power Commission,* 343 U.S. 414, 418, 72 S. Ct. 843, 845, 96 L. Ed. 1042 (1952). See also *F.E.R.C. v. Electric Power Supply Association,* 136 S. Ct. 760, 781, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016) ("The statute aims to protect 'against excessive prices' and ensure effective transmission of electric power.")

against unreasonable charges.[37] The FPC initially accomplished this mandate by adopting the Uniform System of Accounts and establishing reporting requirements that provided PUCs with an understanding of the transactions of their state's utilities with the other entities in the holding company. This equipped state PUCs with the evidence they needed to identify and disallow excessive and extortionate charges.

But FERC and its predecessor (the FPC) have a checkered history in creating this permanent and effective federal bond of customer protection. At times, both the FPC and FERC have had the scope of their authority clarified by the courts, which mandated them to exercise their authority when they did not do so proactively. One such case was the clarification of the FPC's authority under the Natural Gas Act, as Stephen (now Justice) Breyer observed "(in) 1954, somewhat to the FPC's surprise, the Supreme Court held in *Phillips Petroleum Co, v Wisconsin* that act also gave the commission authority to regulate the prices at which field producers sold gas to the pipelines."[38] Clark A. Hawkins performed an extensive study of the regulatory development of field price of natural gas, finding that "the Federal Power Commission was unprepared and unequipped to exercise the dictum of the court."[39] It is not clear that any regulatory agency could have performed the task required by the Phillips decision, imposing cost-of-service ratemaking on thousands of wellheads, many with significantly different physical characteristics, e.g., some were producing both natural gas and oil, while others only produced natural gas. Ultimately, the experience with natural gas was that a single magic formula was not sufficient to fulfill the FPC's responsibility. The question now is whether a single magic pricing formula is sufficient to guide the transformation of the electric industry and whether the Commission will be prepared and equipped to meet the challenges of electrification and decarbonization by developing new methods of pricing.

The FPC adopted a regulatory structure for the field price of natural gas based upon "cost-of-service" principles. A particularly difficult issue in determining the cost of producing gas from a well was the allocation of joint costs when the well produced both oil and gas. By 1960, there were more than 3,300 independent gas producers, with approximately 11,000 rate schedules on file at the FPC.[40] The FPC recognized the complexity of the problem of regulatory governance over such a large group of diverse entities. In response, it established a system of area pricing, with the goal of setting prices "which will be adequate to maintain the gas supplies needed by the consumers of the nation, but at prices no higher than are necessary to accomplish this purpose."[41]

FERC's administration of its customer protection role continues to be largely reactive to events that highlight market failures or to judicial mandates.

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37 *Electrical District No. 1 v. F.E.R.C.*, 774 F.2d 490, 492 (D.C. Cir. 1985), abrogated by *Transwestern Pipeline Co. v. F.E.R.C.*, 897 F.2d 570 (D.C. Cir. 1990) ("[I]t would be unlawful to allow the unjust or unreasonable rate to continue in effect."); *Atlantic Refining Co. v. Public Service Commission of the State of New York*, 360 U.S. 378, 388, 79 S. Ct. 1246, 1253, 3 L. Ed. 2d 1312 (1959).

38 Breyer, Stephen, *Regulation and Its Reform*, Harvard University Press, 1982, p. 243. (internal footnotes omitted) Some argue that the Supreme Court made a disastrous decision in the *Phillips* decision because it failed to giver proper deference to FPC in its decision to assume that wellhead sales fit within the NGA's reservation of production and gathering of natural gas to the states – and that it need not view these as sales for resale subject to FPC jurisdiction. See, generally, *Phillips Petroleum Co. v. State of Wisconsin,* 347 U.S. 672, 74 S. Ct. 794, 98 L. Ed. 1035 (1954).

39 Hawkins, C.A., *The Field Price Regulation of Natural Gas*, Florida State University Press, 1969, p. 36.

40 Ibid, p. 77.

41 FERC Opinion 338 (p. 11) cited in Hawkins, C.A., *The Field Price Regulation of Natural Gas*, Florida State University Press, 1969, p. 78.

III. The Primacy of Markets over Cost-of-Service Regulation

A. The Reliance on Markets to Meet the Just and Reasonable Standard

Beginning in the late 1970s, there was a shakeup in regulation worldwide, with the growing recognition that certain segments of regulated industries could operate competitively. In the late 1970s, Alfred Kahn, then the chairman of the Civil Aeronautics Board, led the first effort at moving from regulated cost-of-service pricing to market prices in the United States. This work transformed the airline industry by moving it from regulated pricing to market-based pricing.

Alfred Kahn's restructuring of the airline regulation led to changes in regulation across industries. The intellectual impetus for deregulation at FERC was a study by Stephen Breyer and Paul MacAvoy on the effectiveness of the FPC's regulation in the 1960s. Breyer and MacAvoy found that "arguments to the effect that competition does not exist in the gas production industry are unconvincing."[42] Problems in the pricing regime for the field price of natural gas created two distinct markets separated by regulatory jurisdiction: interstate and intrastate. This regulatory dichotomy introduced price disparity between these two markets, with interstate prices below those within the states. Needless to say, producers preferred selling into the intrastate markets, creating shortages so significant in the interstate markets that customer usage was curtailed. One way to eliminate that disparity was to shift from complex regulatory models of cost-of-service to market prices. The Natural Gas Policy Act of 1978 began the process of deregulating the well-head price of natural gas, a process completed by the Natural Gas Wellhead Control Act of 1989.[43] This deregulation allowed the equalization of intrastate and interstate prices, freeing up the supply of gas and turning gas shortages into what became known as the "gas bubble."[44]

Along with deregulation of the field (wellhead) price of natural gas, there was a movement to change the regulatory approach to the transportation network of pipelines. Historically, natural gas pipelines offered bundled service; that is, they acquired the natural gas at the field and transported it to the end user (i.e., the ultimate customer that uses the energy). The rates were set on a cost-of-service basis, with costs determined by a group of 600 analysts at the FPC, who evaluated the detailed costs that the pipeline companies incurred to provide service.

Deregulation shifted the development of prices from cost-of-service to market-based rates. To effectuate this change, tariffs that provided schedules of utility prices moved from actual prices to methods of making prices. In creating open access to the pipeline network, FERC separated the transportation and sales functions of the pipeline. In the 1992 penultimate order (636) deregulating natural gas, FERC prohibited pipelines from engaging in merchant gas sales and required non-discriminatory access and prices for transporting gas on the interstate pipeline system.[45] These changes created a market for gas in which buyers had the ability to shop among different suppliers.

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42 Breyer, Stephen and Paul MacAvoy, *Energy Regulation by the Federal Power Commission*, The Brookings Institution, 1974, p. 63.

43 15 U.S.C. 3301.

44 Arndt, M., "Gas 'Bubble' Days May be Numbered," *Chicago Tribune*, February 7, 1988, https://www.chicagotribune.com/news/ct-xpm-1988-02-07-8803280521-story.html.

45 *Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation; and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol,* 57 Fed. Reg. 13,267 (April 16, 1992), *FERC Statutes and Regulations* P 30,939 (April 8, 1992), *reh'g granted and denied in part*, Order No. 636-A, 57 Fed. Reg. 36,128 (August 12, 1992), *FERC Statutes and Regulations* P 30,950 (August 3, 1992), *order on reh'g*, Order No. 636-B, 57 Fed. Reg. 57,911 (December 8, 1992), 61 FERC P 61,272 (1992).

One critical lesson that FERC learned from its successful experience with restructuring the natural gas industry was the importance of separating the merchant and transportation functions. In natural gas, the merchant function is the sale of gas at the wellhead and the transport function is shipping via pipelines. In the electricity industry, the generation of power is a merchant function, and the transmission and distribution of power is a transportation function.

By the late 1980s, the electric industry began accumulating experience with the separation of the merchant function from the transmission function. That is when the state PUCs established long-run rates for independent generation in compliance with the Public Utilities Regulatory Policies Act of 1978 (PURPA). PURPA required utilities to purchase power from qualified independent generators at rates set at the utility's "avoided cost." Avoided cost was defined as the cost that the utility would have incurred "but for" the purchase of power from the independent producer. This administrative pricing process enabled the entry of non-utility generators and demonstrated that the power system could be reliably coordinated with power supplied by non-utility generators. At the same time, it also created financial issues for the purchasing utilities, because the prices paid were based on forecasts that assumed certain levels of non-utility supply. Price schedules were fixed, so if one generator was economic to build, an unlimited number of generators were economic, since they typically relied on advanced combined cycle technology burning natural gas. In California, utilities signed contracts for more than 15,000 MW of new capacity, with more than 3,000 MW on-line and operating, reviving the term "gold rush" by William Ahern, the director of the Public Staff Division of the California Public Utility Commission.[46] Because prices did not change with the level of power supplied (i.e., administratively inelastic prices), utilities were required to purchase more than they needed at prices greater than the power was worth. And, not surprisingly, a number of utilities ended up in significant financial difficulty.

The inelastic (non-price-responsive) avoided-cost methods[47] had an extreme impact on the Niagara Mohawk Power Company (NMPC), an upstate New York utility. By 1993, NMPC's non-utility generator purchases were approximately 28 percent of its power supply, but 67 percent of its costs.[48] The utility's anticipated installed capacity reserve margin was forecast to grow to 40 or 50 percent by the late 1990s (as compared to the 18 percent requirement at the time). The company ultimately lost a great deal of money (much of which was recovered from ratepayers) when it restructured the contracts, paying independent power producers $3.6 billion in cash, 20.5 million in shares of common stock, and the proceeds from the sale of an additional 22.4 million shares of stock.[49]

PURPA helped spur interest in creating wholesale competitive power markets. Utilities saw these markets as a way to avoid the requirement to contract at administratively determined fixed prices. Industrial customers viewed competition as a way to lower their cost of power. Non-utility generators saw competitive markets as creating new market opportunities that eliminated the utility as the (frequently unenthusiastic) agent in the middle. These interests began to converge in the early 1990s with the restructuring the electric industry and its regulation.

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46 Ahern. W., "Implementing Avoided Cost Pricing for Electricity Generators in California," *Mimeo,* Jan. 12, 1987.

47 One factor that exacerbated the inelastic nature of the method was an implementation issue. The avoided cost schedules were re-evaluated on a fixed schedule as opposed to being re-evaluated based on changing circumstances, i.e., greater contracting of new generation than expected.

48 Niagara Mohawk Securities and Exchange Commission 10-k for fiscal year ending December 31, 1993 (Washington, DC: Securities and Exchange Commission, 1993), http://www.getfilings.com/o0000071932-94-000038.html.

49 "NiMo Completes Deal with Independents," *Albany Business Review*, June 30, 1998, http://www.bizjournals.com/albany/stories/1998/06/29/daily6.html.

Another important impetus for restructuring the U.S. electric system came from watching the privatization of the electric system in Great Britain, which moved to competitive markets from a somewhat different direction than the United States. In Great Britain, prior to restructuring, the electric industry was nationalized and the move to competition was part of its privatization.[50] The privatized electric market in England and Wales began trading electricity on April 1, 1990. This market replaced the inefficient government monopoly, the Central Electricity Generating Board.

An important outcome of restructuring was that generators selling into the market now did so under FERC's grant of market-based rate authority. To receive this right, a generator first needed to demonstrate that they did not have market power. The California Energy Crisis (discussed later) demonstrated that the analytical tests used proved to be insufficient.

In the United States, in 1992, Congress fundamentally changed the federal regulation of electricity with the passing of the Energy Policy Act of 1992 (EPACT).[51] EPACT made two fundamental changes to the regulation of electric markets. First, it gave FERC the power to order open-access to wholesale electric markets. Second, it created a new class of generation ownership, "exempt wholesale generators" (EWGs). This new form of ownership allowed entities outside the utility industry to own generation without the entire firm being subject to regulatory reporting requirements. This greatly liberalized ownership, enabling banks, hedge funds, retirement plans, and other industries to become active participants in power generation.

FERC issued two orders in 1996 (Order Nos. 888 and 889)[52] that effectively unbundled[53] the costs of generation and transmission. It also required utilities to file Open Access Transmission Tariffs (OATT). It did so based on the powers entrusted to it by the FPA in the prohibition against "undue preference and advantage." These tariffs provided information about the price and value that utilities placed on the various aspects of providing service. Today, the "Open Access Same-time Information System" (OASIS) provides transparent information on transmission availability and cost to all market participants giving the transmission market the information needed to become competitive. Importantly, Order Nos. 888 and 889 also established the basis for creating the Independent System Operators (ISOs) that coordinate the power markets and operate the reliable delivery of power, similar to the way that air traffic controllers direct airplanes.

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50 "The Thatcher government's resolve to privatize the electricity and coal industries was solidified by the effects of the coal-miner strike of 1984-1985." Indeed, one of the objectives of the privatization of the electric industry in the UK was to break the coal miner unions. See Hadjukanbrunism C., "Restructuring the Electricity Industry in Britain and Norway," *IEEE Technology and Society Magazine,* February, 2006, pp. 27-35, https://www.researchgate.net/publication/3226869_Restructuring_the_electricty_industry_in_Britain_and_Norway.

51 *Energy Policy Act of 1992*, Pub.L. No. 102-486, 106 Stat. 2776 (1992).

52 *Promoting Wholesale Competition Through Open Access Nondiscriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, 61 Fed.Reg. 21,540 (1996), *clarified,* 76 FERC ¶ 61,009 and 76 FERC ¶ 61,347 (1996) ("Order 888"), *on reh'g,* Order No. 888–A, FERC Stats. and Regs. ¶ 31,048, 62 Fed.Reg. 12,274, *clarified,* 79 FERC ¶ 61,182 (1997), *on reh'g,* Order No. 888–B, 81 FERC ¶ 61,248, 62 Fed. Reg. 64,688 (1997), *on reh'g,* Order No. 888–C, 82 FERC ¶ 61,046 (1998); *Open Access Same–Time Information System and Standards of Conduct,* Order No. 889, FERC Stats. & Regs. ¶ 31,035, 61 Fed.Reg. 21,737 (1996) ("Order 889"), *on reh'g,* Order No. 889–A, FERC Stats. & Regs. ¶ 31,049, 62 Fed. Reg. 12,484 (1997), *on reh'g,* Order No. 889–B, 81 FERC ¶ 61,253 (1997).

53 Unbundling is the process of making available for separate sale two products, one a monopoly product and one a competitive productive, previously sold as an inseparable bundle. A necessary feature of unbundling is separating the cost of the different services. In vertically integrated utilities the cost of transmission, distribution and generation are "bundled" into electric rates. Unbundling allows the separate purchase, at separate rates, of three distinct services: distribution, generation and transmission. Unbundling thus enables competitive providers to offer generation services to retail customers.

In summary, FERC's focus and practice of regulation changed as a consequence of the successful transformation of the natural gas industry in the 1980s from a heavily regulated industry to one reliant on competitive markets, and the agency's desire to repeat that success by developing other competitive markets. This change began in the 1990s, with FERC shifting its assessment of just and reasonable rates for electricity from cost-of-service regulation to prices determined by a competitive market.[54]

> FERC's core assumption in its restructuring efforts has been that competitive markets what it sometimes refers to as "the forces of competition"-can be relied upon to ensure that prices for natural gas and electricity satisfy the statutory just and reasonable standard.[55]

Importantly, while FERC was pursuing a policy of creating competitive markets, the states remained free to continue regulating vertically integrated monopolies. The nature of the markets regulated by the FERC depended heavily on whether state action required utilities to divest their generation and purchase power in the wholesale markets rather than supplying power to their customers from generators that were part of the utility's rate base.

FERC regulates wholesale electric markets that serve 66 percent of total U.S. load. The three Northeast ISOs: the New York ISO (NYISO); ISO-New England (ISO-NE); and the Pennsylvania, Jersey, Maryland Interchange (PJM) comprise 41 percent of total ISO s load and 27 percent of total U.S. load.[56] FERC has a special relationship with the three Northeastern ISOs, dating back to before electric restructuring in the 1990s. Each of these ISOs had its operational and market genesis in "tight" power pools that were transformed into markets for power. Each of these serves a region in which vertically integrated utilities have divested their rate-based generation and sold it to entities that receive remuneration through the market. In these areas, retail service is provided either through regulated incumbent distribution utilities or merchant "load-serving entities" (LSEs). It is in these areas that the FERC is most reliant on the magic pricing formula.

B. Glitches on the Path to Competition — the California Energy Crisis

On the path to competition, FERC and state PUCs learned many important and painful lessons about the shift from state oversight to federal oversight in terms of customer protection. A key example of this are the lessons learned in the California Energy Crisis.

The California power market opened on March 31, 1998, formalizing the shift in the coordination of the state's power generation and delivery from vertically integrated utilities to market-based competition.[57] By May 2000, however, that market had broken down as a result of the exercise of market power by sellers into the market. A drought in the Pacific Northwest reduced the availability of hydro-electric power, creating a thin market. Market participants, such as Enron, then drove up market prices through a series of games and manipulation such as "ricochet," in which they sold power outside the state and then resold it back into California to avoid the price caps that applied only to

54 In this process, the role of the tariff changed from providing explicit price schedules, to providing mechanisms for establishing price.

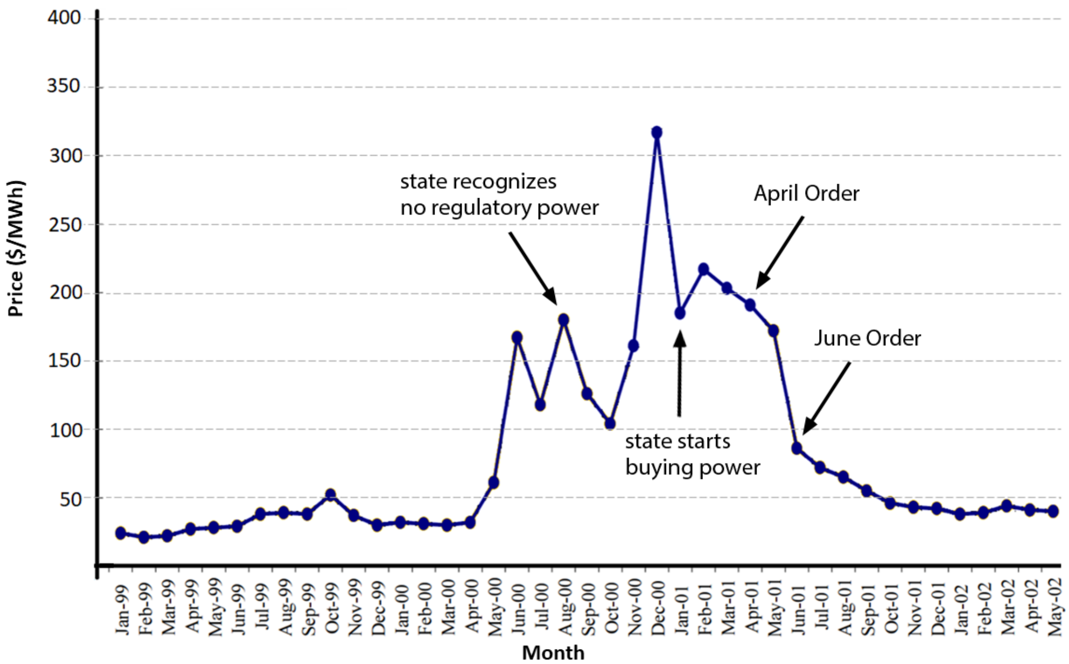
55 Boyd, W., "Just Price, Public Utility, and the Long History of Economic Regulation in America." *Yale Journal on Regulation*, Vol. 35, 2018. p. 727.

56 NERC 2019 Electricity Supply Demand (ES&D) – Released December 2019, Total Net Energy for Load (NEL) represents actual data for 2018. NEL data for CAISO includes some non-CAISO entities and a small portion of Mexico, http://www.nerc.com/pa/RAPA/ESD/Pages/default.aspx.

57 The power market in California was initially coordinated by two entities, the Power Exchange (PX) that coordinated economic transactions and the ISO that coordinated the reliable operation of the market. This structure proved unworkable and the ISO absorbed the PX functions.

in-state transactions.[58] As demonstrated by **Figure 1,** market prices exploded. The state's utilities faced increasing financial difficulty because of regulatory limitations on passing through price increases to customers,[59] ultimately leading to PG&E's bankruptcy.

Figure 1: California Wholesale Electricity Prices, Before, During, and After the Energy Crisis (Monthly Average)[60]



The state was desperate to find a way to resolve the crisis. But, as the chairman of the California Electricity Oversight Board, Michael Kahn, and California Public Utility Commission Chair Loretta Lynch wrote to Governor Gray Davis in August 2000 during the early days of the crisis,

> "A momentous consequence of California's attempt to create a [competitive] market in electricity is that the federal government now regulates California's electric system."[61]

This resulted from the fact that FERC has authority for wholesale sales in interstate commerce.

58 Martin, M., "'Smoking gun' Enron memos/ 'Death Star,' 'Get Shorty' strategies show how firm manipulated energy to state in attempt to boost profits," *SFGate*, March 5, 2007, https://www.sfgate.com/news/article/Smoking-gun-Enron-memos-Death-Star-Get-2840998.php.

59 This was a feature of the California restructuring law AB1890, which froze rates to retail customers until stranded costs of the transition to competition were paid off. As the crisis began, San Diego Gas and Electric had resolved its stranded cost issues and was able to pass on higher market prices. Pacific Gas & Electric and Southern California Edison had not, and because they were unable to pass on the unprecedented market prices both suffered significant financial harm, with PG&E declaring bankruptcy.

60 Modified from http://www.caiso.com/Documents/CAISOState-MarketReport_AnjaliSheffrin_FERCMarketMonitoringPresentation_June26_2002.pdf, p. 5. Used with Permission.

61 Kahn, M. and Lynch, L., "Letter to Governor Gray Davis," August 2, 2000, p. 5.

FERC was slow to embrace its new role as a regulator of wholesale market prices and to quell the unexpected high prices resulting from the exercise of market power and market gaming on the part of sellers into the California market. FERC's remedial response[62] was also slow and economically naive. As demonstrated by **Figure 1,** FERC's April 2001 Mitigation Order[63] came at a time when the market prices had already risen significantly above what they were when Governor Davis was informed that the regulation of prices in the market was FERC's responsibility. To resolve this problem, FERC called for a change in the underlying auction mechanism used in the market, causing a shift from uniform price auctions, with a single clearing price, to "pay-as-bid" auctions, in which every generator would be paid what they bid. As Alfred Kahn wrote, "Any belief that a shift from uniform to as-bid pricing would provide power purchasers substantial relief from soaring prices is simply mistaken."[64]

Through the spring and early summer, market prices began to come down. The state entered into long-term contracts through the Department of Water Resources to reduce its exposure in the California Independent System Operator's (CAISO) spot markets. The state's purchase of power under long-term contracts reduced the amount of power in the spot markets, thereby limiting the ability to exercise market power. The price reductions were also a result of the increased attention to the behavior of the markets themselves. Ultimately, on June 19, 2001,[65] FERC required a form of cost-of-service justification for prices charged in the markets.

The carnage of the California energy crisis led to a great deal of political fallout, including the recalling of California Governor Gray Davis. It also became apparent that FERC had failed in its critical role of customer protection. As FERC noted:

> During the Western Energy Crisis, the Commission's enforcement tools lagged behind these market developments, and the schemes exposed a major weakness in the Commission's ability to fulfill its core mission of ensuring just and reasonable rates and protect energy market participants and consumers. Until the Commission enacted the Market Behavior Rules applicable to electric markets and code of conduct applicable to natural gas markets in the aftermath of the Western Energy Crisis, neither the statutes administered by the Commission nor its rules, regulations, or orders contained any explicit prohibition or definition of market manipulation.[66]

In response to FERC's lack of sufficient authority to regulate market manipulation that became evident during the California Energy Crisis, Congress provided FERC with anti-manipulation authority. To exercise that authority, FERC created the Office of Enforcement that "serves the public interest by protecting consumers through market oversight and surveillance."[67] Since the office's formation in 2007, FERC has assessed total civil penalties of $784,194,020 and

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62 *San Diego Gas & Electric Company, Complainant v. Sellers of Energy and Ancillary Service into Markets Operating by the California Independent System Operator,* Order Establishing Prospective Mitgation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Western Wholesale Electric Markets." 95 FERC ¶ 61,115 (2001) ("FERC April 26, 2001 Mitigation Order") ERC "Order Establishing Prospective Mitigation and Monitoring Plan for the California Wholesale Electric Markets and Establishing an Investigation of Public Utility Rates in Wholesale Western Energy Markets." April 26m 2001 ¶ 61,115, FERC April order.

63 *FERC April 26, 2001 Mitigation Order*, 95 FERC ¶ 61,115 , 61354 (2001)

64 Kahn, A.E., Crampton, P., Power, R.J., and Tabors, R.D., "Uniform Pricing or Pay-as-Bid Pricing: A Dilemma for California and Beyond," *Electricity Journal*, July 2001, pp. 70-79.

65 *FERC June 19, 2001, Order on Rehearing Docket EL00-031.*

66 Federal Energy Regulatory Commission, "Staff White Paper on Anti-Market Manipulation Enforcement Efforts Ten Years After EPACT, 2005," November 2016, https://www.ferc.gov/sites/default/files/2020-05/marketmanipulationwhitepaper.pdf.

67 https://www.ferc.gov/about/offices/office-enforcement-oe.

ordered a disgorgement of $518,070,718.[68] However, even with this level of activity, then Commissioner Moeller in his article "Has the "Complete and Permanent Bond of Protection" provided by FERC Refunds Eroded in the Transition to Market-based Rates?" concluded that "under market-based rates, consumers are less likely to be made whole when rates are found to be unjust and unreasonable, or unlawful, than under traditional cost-based regulation."[69]

FERC now reflects the primacy of markets in its mission statement: "Economically Efficient, Safe, Reliable, and Secure Energy for Consumers."[70]

IV. FERC's 'Magic Formula' for a Just and Reasonable Price

FERC has adopted a basic pricing formula in its oversight of wholesale electric markets. It is this oversight that forms the bond of customer protection, what Landis called the "magic formula" to determine the price of electricity in competitive wholesale markets. Although Landis was focused on the field price of natural gas, his concept is equally relevant today to understand FERC's oversight of wholesale electric markets. That concept is a single, simple approach to a complex problem.

The question is whether a single, simple conceptual model that defines just and reasonable prices should guide the regulation of electric markets. The Peaker Method provides the economic basis for determining prices in competitive markets and underpins FERC's magic pricing formula. Reliance on the Peaker Method supported the shift in regulatory focus from a cost-of-service basis for determining the price of wholesale power transactions between utilities to relying on market prices as the basis for the just and reasonable prices paid to a wide variety of market participants. From an economic perspective, competitive markets are efficient. Although FERC does not provide a clear and readily available definition of its view of economic efficiency,[71] it is reasonable to infer its definition from the history of its price regulation practice.

The Peaker Method is based on the practical application of a rich economic literature on the theory of peak load pricing.[72] As Joskow points out, "Perhaps, ironically, the conceptual basis for the design of organized wholesale electricity markets in the US during the late 1990s and early 2000s can be traced directly to the mid-twentieth century economic-engineering literature."[73] The Peaker Method got its name during the implementation of PURPA in the late 1980s. And it implicitly became the basis for the organized electric markets regulated by FERC in the 1990s.

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68 Boyd, W., "Ways of Price Making and the Challenge of Market Governance in U.S. Energy Law," UCLA School of Law, Public Law & Legal Theory Research Paper No. 20-23 August 2020, p. 7, forthcoming 105 Minn. L. Rev. (2020), https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3682881.

69 Moeller, P., ""Has the "Complete and Permanent Bond of Protection" provided by FERC Refunds Eroded in the Transition to Market-based Rates?," *Energy Law Journal*, Vol. 33:41, 2012, p. 41.

70 https://ferc.gov/about/what-ferc, July 13, 2020.

71 For example, in its Strategic Plan FY 2018 – 2022 (September 2018) FERC uses the term efficiency without definition https://www.ferc.gov/sites/default/files/2020-04/FY-2018-FY-2022-strat-plan.pdf A search of FERC website did not yield a definition either.

72 See: Boiteux, Marcel P. «La tarification des demandes en pointe: Application de la théorie de la vente au coût marginal,» 1949, *Revue générale de l'électricité*, Steiner, P.O. Peak Loads and Efficient Pricing" *Quarterly Journal of Economics*, 71 (November, 1957), pp. 585-610. Turvey, R. (1968), *Optimal Pricing and Investment in Electricity* Supply, London, George Allen and Unwin. Peak Load Pricing with a Diverse Technology" *Bell Journal of Economics* 7, No. 1 (Spring, 1976), pp. 207-231.

73 Joskow, p. 299.

Marginal energy costs are the incremental costs of providing generation.[74] These costs are revealed as a direct outcome of the ISO auction-based economic dispatch process that coordinates power plants to balance supply and demand for power. The real-time (instantaneous) market price is equal to the marginal cost of the generating unit (or demand response offer) used to meet the last increment of load. This is the standard economic definition, where the competitive market price equals marginal cost *(p=mc).* And, as demonstrated by the discussion of PJM in the Appendix, ISOs have tremendous capabilities to determine this price in real-time.

Price provides the basis for investment cost recovery. While the theory underlying the Peaker Method was developed in the late 1940s, when cost recovery was solely through utility rates, its practical implications were revealed as generation recovered costs through the market prices. The market problem that this theory foreshadowed is the revenue shortfall underlying the missing money problem.

The economic theory of peak load pricing supporting the Peaker Method demonstrates that there is no way to recover costs based on competitive energy market prices. In an optimal system, with all costs recovered through energy prices, there will still be a revenue shortfall equal to the cost of a peaker. Why are these costs based on the cost of a peaker? The answer is that, historically, the only reason to build a peaker was for reliability. A peaker would only be used either during periods of peak demand or when there was a failure on the system. Every other kind of generator earned inframarginal rents, the difference between the market price and the generator's marginal cost. Peakers don't earn economic rents, because they are the most expensive units on the system to operate. The way this fits into the optimal system is based on two things: (1) the tradeoff in the capital cost of different types of capacity and the marginal costs of producing electricity, and (2) the need to maintain reserves to operate reliably. When the peak load pricing literature was developed, there was a tradeoff between the different capital costs and operating costs of different technologies. That tradeoff led to generators collecting inframarginal rents that supported capital cost recovery. The amount of capital cost recovery depended both on the level of infra-marginal rents and the amount of time that the generator received those rents. Therefore, a base load generator, such as a nuclear power plant, with high capital costs and low operating costs would typically accrue rents throughout the day. For this reason, an optimal configuration takes into consideration the tradeoff of capital costs and operating costs. This tradeoff leaves a revenue shortfall equal to the cost of a peaker.

As a consequence of this shortfall, the peak load pricing theory suggests that a form of capacity payment is needed to recover costs. Building on that theory, the Peaker Method provides a method for recovering the revenue shortfall (the missing money). This value represents a convergence of electrical engineering and economics. Economists have equated the established reserve margins[75] into economically optimal levels of capacity. Any increase in consumption incurs the marginal cost of the increased generation plus a reduction in the reliability of the system. This incremental reduction in reliability is called "the marginal expected curtailment cost."[76] Therefore, at the required reserve margin, the marginal expected curtailment cost is equal the cost of a peaker.[77] This identity is then used in price making through the mechanisms discussed later in the paper.

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74 For the purposes of this paper, ancillary costs are considered part of energy costs.

75 The required amount of generation above the forecast peak load.

76 More formally – this is the Value of Loss Load X the probability of being disrupted.

77 Typically, this is evaluated over the course of a year, so that the cost of the peaker would be presented as an annual revenue requirement.

Therefore, FERC's magic pricing formula, Is:

$$\left\{\begin{matrix}\text{Market}\\\text{price}\end{matrix}\right\} = \left\{\begin{matrix}\text{Marginal}\\\text{Energy Cost}\end{matrix}\right\} + \left\{\begin{matrix}\text{Marginal Expected}\\\text{Curtailment Cost}\end{matrix}\right\}$$

For a more detailed description of the Peaker Method and how it forms of the basis of FERC electric pricing regulation, see Appendix A.

A. Implementing the Magic Formula

As described here, the Peaker Method provides FERC with its magic formula for just and reasonable prices and, therefore, customer protection. This formula has two components. The first is the energy component, a short-run price that reflects the cost of dispatch, i.e., the short-term cost of operating the dispatched unit. The second is the generation capacity payment. There are three mandatory[78] capacity markets regulated by FERC (NYISO, ISO-NE, and the PJM). Although they are all different, FERC has implemented its single magic formula to determine pricing in each. The revenues derived from capacity payments are significant: $51 billion from 2013 through 2016 in payments to generators in these four markets.[79] However, as will be discussed later, not all organized electric markets include capacity markets.

1. FERC's focus on energy markets

FERC developed ISOs[80] as a key platform for operating competitive power markets. The ISOs provided non-discriminatory service, breaking the link of utility control over power production. The design of ISOs followed the magic formula of an energy plus capacity charge.

The initial focus of market design was on establishing real-time energy markets for operating the system. Sally Hunt, in her book *Making Competition Work in Electricity*,[81] outlines four pillars of market design:

1. Imbalances
2. Congestion management
3. Ancillary services
4. Scheduling and dispatch

All of these are important issues for the operation of an electrical system and are not related to the capacity component.

78 As described by PJM, "Each PJM member that provides electricity to consumers must acquire enough power supply resources to meet demand not only for today and tomorrow but for the future. Members secure these resources for the future through the PJM capacity market," https://learn.pjm.com/three-priorities/buying-and-selling-energy/capacity-markets.aspx.

79 GAO, "Electricity Markets: Four Regions Use Capacity Markets to Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance Report to Congressional Committees," GAO-18-131, December 2017, p. 1.

80 The lexicon of power markets is somewhat confusing because there are two different types of organizations that are incorporated into a single entity. ISOs monitor, coordinate and control the operation of electric systems. RTO's coordinate, monitor and control the transmission system. The two are inextricably linked. For the purpose of simplicity, the term ISO is used for ISO/RTOs.

81 Hunt, Sally, *Making Competition Work in Electricity*, John Wiley & Sons, 2002, p. 128.

Keeping the lights on while transforming the grid from a cost-based system of regulated utilities to a market of merchant entities has been a non-trivial, all-consuming task. Early efforts in creating the three Northeastern ISOs focused largely on transforming existing power pools.[82] Power Pools were organizations, regulated by FERC, that facilitated the trading of power between utilities. To do this, the pool dispatch models were transformed from algorithms that used cost data to one that uses offers provided by suppliers (generators and marketers).

This transformation meant that services that had been performed as a matter of course by regulated utilities were now provided by organized energy markets (ISOs) through a variety of new market products. Given the focus on energy markets required to keep the lights on, it is not surprising, therefore, that, as Joskow observed, "(i)n my view, the initial 'centralized' wholesale market designs in the US paid too little attention to their investment incentive properties."[83] These incentive properties would include the ability to earn adequate revenues to both amortize generation investments and make a profit.

2. Development of capacity markets

The economic theory underlying the Peaker Method has had a direct impact on the design of capacity markets. The theory predicts that generators in competitive energy markets will be unable to recover their capital investment without the unfettered ability to raise prices during periods of shortage. The limitation imposed by price caps recognizes the ability of generators to exercise market power during times of shortage. Price caps are limits on what the generators can be paid in the markets. They are an administrative proxy for the exercise of market power.

The inability of generators to recover their capital investment through energy market prices is the cause of the missing money problem. The extent of a generator's missing money problem depends on its accrual of inframarginal rents. Therefore, the ability to recover capital costs is dependent on how long the generator can stay on the price duration curve at levels above its marginal cost of operation. The closer to peak consumption, the higher the likelihood of moving up the steep portion of the supply curve[84] with increasingly expensive generators to operate. Capacity shortages occur when there is insufficient generation to meet the inelastic demand for power. At that point, generators can charge above their marginal costs. Some call this scarcity rents. Others call this the exercise of market power by pricing as pivotal suppliers.[85] There is some truth to both ideas, because without a capacity market, scarcity pricing is an important tool for capital cost recovery. The problem is that there is no theoretical limit to the level of scarcity pricing or the level of generator profitability. Because merchant generators do not share their books with regulators to determine how profitable they are, it is important to have a check on market power. That is why ISOs adopted price caps. In the transformation from cost-of-service to market-based regulation of the electric industry, little attention was paid to theory, and, therefore, the underlying lesson of the Peaker Method was lost. Again, that lesson is that in an optimal capacity mix, where generators are compensated based on the market price, every generator will have a revenue shortfall equal to the cost of a peaker. If properly compensated through a capacity payment, there will be no missing money problem.

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82 An exception is the creation of the California Power Exchange and Independent System Operator which were newly created entities.

83 Joskow, P., "Challenges for wholesale electricity markets with intermittent renewable generation at scale: the US experience," *Oxford Review of Economic Policy*, Volume 35, Number 2, 2019, pp. 291–331, p. 302.

84 Known as the hockey stick – see Appendix A, Exhibit A4

85 Generators required to meet demand, thereby providing the ability to raise prices.

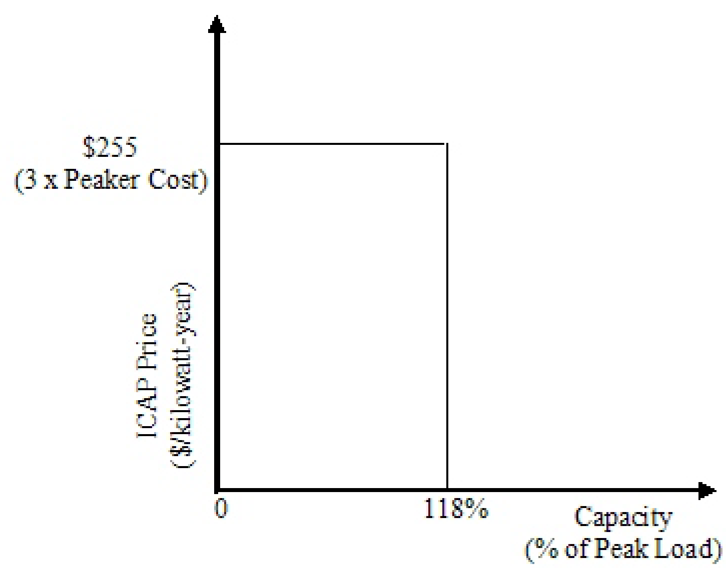
The early transition to competitive markets handled the issue of revenue adequacy through traditional cost-of-service rates, but it did so only for power plants required to maintain reliability. These rates, called Reliability Must Run (RMR) contracts, were used to ameliorate the revenue shortfall for power plants in critical electrical locations. In California, "(s)ince the ISO startup in 1998, the ISO has relied on RMR agreements to secure essential services from resources to reliably operate the grid."[86]

The earliest capacity markets were established by adopting procedures developed to ensure resource adequacy (the required installed reserve margin) in power pools. The three northeastern ISOs (NYISO, ISO-NE, and PJM) all evolved from power pools that had installed reserve requirements. With restructuring, the question arose of as to which entities would be responsible for ensuring that installed reserve margins were met. Under the competitive regime called "retail access," new entities, called "Load Serving Entities" (LSEs), provided competitively-priced energy to retail customers. Because it was not reasonable to have the incumbent utility incur the cost of reserves for power sold by its competitors, that responsibility shifted to the load-serving entities (which included (a) utilities in non-retail competition states and (b) utilities in retail competition states that had the obligation to provide service to customers that did not shop with competitive suppliers). This made capacity a product in the competitive markets. The Deficiency Payment concept, as depicted in **Figure 2** emerged from the rules of the New York Power Pool as a method of addressing the need for ensuring capacity reserves.

The problem with the deficiency charge was that it created a bimodal pricing structure. When there was sufficient generation, the market price approached zero. When there was a shortage of capacity, the capacity price was equal to the deficiency payment. In New York, the deficiency payment was three times the cost of a peaker.

In response to complaints by the state's merchant generators about volatile revenues resulting from a capacity market based on deficiency payments, the New York ISO proposed a generation capacity market based on what was labeled the "demand curve" proposal. This proposal provided a simplified characterization of a demand curve based on the Peaker Method. The notion behind the demand curve is that it reflects customer valuation of reliability. Using the demand curve instead of a strict reserve margin criteria (which reflects inelastic demand for reliability) smooths out price volatility while providing revenues to generators.

Figure 2: Price Curve Based on Deficiency Payments[87]

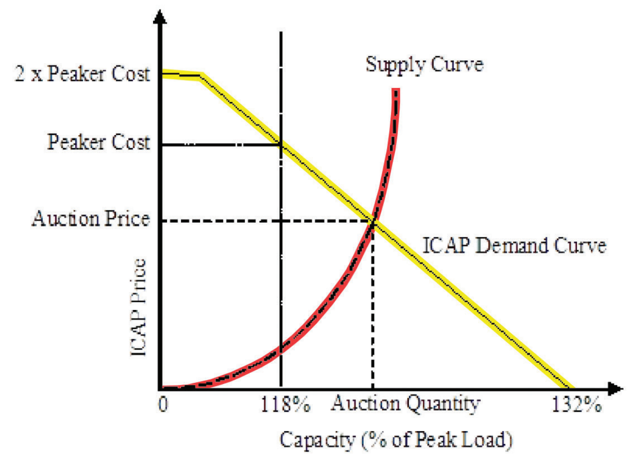


86 CalSO, "Review of Reliability Must Run and Capacity procurement Mechanism," March 13, 2018. http://www.caiso.com/Documents/DraftFinalProposal-ReviewofReliabilityMustRunandCapacityProcurementMechanism.pdf.

87 See, *Electricity Consumers Resource Council v. F.E.R.C.*, 407 F.3d 1232, 1234 (D.C. Cir. 2005). ("*ECRC v. FERC*").

Figure 3 demonstrates market making in the New York ICAP (for installed capacity) market. This price-making mechanism is known as the "demand curve." The figure demonstrates both the reliance on the Peaker Method and the role of administrative pricing and market intervention in pricing. The parts of the demand curve highlighted in yellow are a purely administrative price making mechanism. The supply curve is highlighted in red, to indicate that it is subject to administrative price intervention, by which FERC mandates buyer-side mitigation (discussed later), which requires that some sellers at or above an offer floor (which has the effect of increasing prices to consumers). Therefore, we see that the fundamental dynamics in this so-called market are administratively determined. The key theoretical feature sets the demand curve's pivotal point, that the value of capacity at the desired reserve margin (118 percent of peak load) is equal to the CONE (Cost of New Entry). The other two pivotal points that define the demand curve are: (1) the maximum allowable price (two times the cost of CONE) or (2) the point at which the incremental value of capacity (i.e., its price) is zero are not supported by empirical analysis, for example, a study of customer behavior.

Figure 3: The New York Demand Curve[88]



In approving the New York Demand Curve, FERC found that it "will benefit customers because it will provide better price signals to investors for the construction of new generation …"[89] In doing so, the Commission completed its magic formula for the provision of customer protection:

$$\left\{\begin{matrix}\text{Price}\\\text{Making}\end{matrix}\right\} = \left\{\begin{matrix}\text{Energy}\\\text{Markets}\end{matrix}\right\} + \left\{\begin{matrix}\text{Capacity}\\\text{Markets}\end{matrix}\right\}$$

where

$$\left\{\begin{matrix}\text{Market}\\\text{Price}\end{matrix}\right\} = \left\{\begin{matrix}\text{Energy}\\\text{Price}\end{matrix}\right\} + \left\{\begin{matrix}\text{Capacity}\\\text{Price}\end{matrix}\right\}$$

It is worth questioning whether the "demand curve" structure in the New York Capacity Market leads to an efficient outcome that supports its use as part of the magic formula for customer protection. In accepting the demand curve (ICAP) proposal, FERC acknowledged that setting specific parameters required "some measure of judgment."[90] In fact, it is a demand curve in name only, since it does not reflect any estimate of customer demand or show how the curve would look if it were based on a ratio of the loss of load probability (LOLP) of the system as found to its target level. The LOLPs is a reliability metric used for determining resource adequacy (see Appendix for discussion of LOLPs). It is simply an administrative schedule with arbitrary parameters. There is no theoretical reason why the price of capacity ought to be limited to two times the cost of a peaker. Similarly, there is no theoretical reason why the value of capacity ought to go to zero at the arbitrary reserve margin of 32 percent created by the NYISO stakeholder

88 Modified from ECRC v. FERC, 407 F.3d 1232, 1235 (D.C. Cir. 2005).

89 *New York Independent System Operator, Inc.*, 103 FERC ¶ 61,201, 61757 (2003) (New York ISO).

90 *New York ISO*, 103 FERC ¶ 61,201, 61754 (2003).

process. The choice of 32 percent is based on a political compromise, not an analytical conclusion. As a consequence, there is no basis to conclude that these markets are efficient.

The demand curve in New York was created through a stakeholder process. Under FERC's guidance, the governance of ISOs had shifted from power pools, in which the utilities in the New York Power Pool made the decisions on system operation and pricing based on unanimous consent, to a FERC approved stakeholder process that does not require or even usually achieve consensus. One might argue that if the stakeholder process that led to the NYISO proposal was based on a consensus that the adoption of the demand curve was socially optimal, it would therefore also be efficient. However, the NYISO adoption of the demand curve proposal was not based on consensus among the various stakeholder groups participating in the committee process that led to the proposal to FERC. In fact, protesters to the adoption of the demand curve proposal raised "concerns about voting (and) claim(ed) that the proposal only achieved the necessary vote in the stakeholder process because three voters were disenfranchised." FERC rejected this protest, finding that no tariff provisions were violated in the process of determining the appropriate voting requirements because "no Tariff provision controls those decisions."[91] As a consequence, the idea that the proposal is efficient because it reflects a stakeholder process must be rejected.

In response, multiple stakeholders, including Consolidated Edison and the City of New York, pursued judicial appeal of FERC decision. In defending its decision before the U.S. Court of Appeals, FERC argued that "the court owes "special deference" to its development of the "experimental" ICAP Demand Curve, because, regardless of the evidence in the record, "there is no substitute for reviewing the actual results of a regulatory action."[92] The Court afforded the Commission the deference it requested "based on the understanding that the Commission will monitor its experiment and review it accordingly."[93]

The New York ISO is not the only system that adopted a mandatory capacity market. The capacity market is used in ISOs in which generation has been divested from the formerly vertically integrated utilities and customers can choose their energy providers. Both the ISO-NE and the PJM ISO have adopted capacity markets. The three ISOs' markets are very different, but at their core all three share the idea that at the target reserve margin, the value of capacity is equal to the cost of the peaker. Given technological change, combustion turbines are efficient enough to earn infra-marginal rents. Consequently, there has been an evolution in the paradigm away from calling the measure of pure capacity a peaker to calling it the "cost of new entry," or 'CONE.' The calculation of CONE takes into consideration energy revenues from infra-marginal rents to determine the capacity cost of the new entrant.

FERC officials estimate that between 2012 and July of 2017, there were 190 proposals to change capacity markets, 125 of which were accepted and resulted in modifications to the markets.[94] In its report to the Congress examining FERC's oversight of capacity markets, the U.S. General Accountability Office found that "[w]hile FERC has conducted assessments of individual aspects of capacity markets, it has not fully or regularly assessed these markets' overall performance, and it does not use performance information to make improvements."[95] To date, FERC has not

91 *New York ISO*, 103 FERC ¶ 61,201, 61765 (2003).

92 *ECRC v. FERC,* 407 F.3d 1232, 1238 (D.C. Cir. 2005) (internal citations omitted).

93 *ECRC v. FERC,* 407 F.3d 1232, 1239 (D.C. Cir. 2005).

94 GAO, "Electricity Markets: Four Regions Use Capacity Markets to Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance Report to Congressional Committees," GAO-18-131 December 2017, p. 22.

95 GAO, p. 42.

provided a full public assessment of the capacity markets' overall performance. Further, at this point, there is not only a great diversity in the organized capacity markets, but as explained in the next section there is also a great diversity in non-regulated resource adequacy policy and market approaches. A robust analysis of what works and doesn't work in the various markets would provide useful performance information to make improvements.

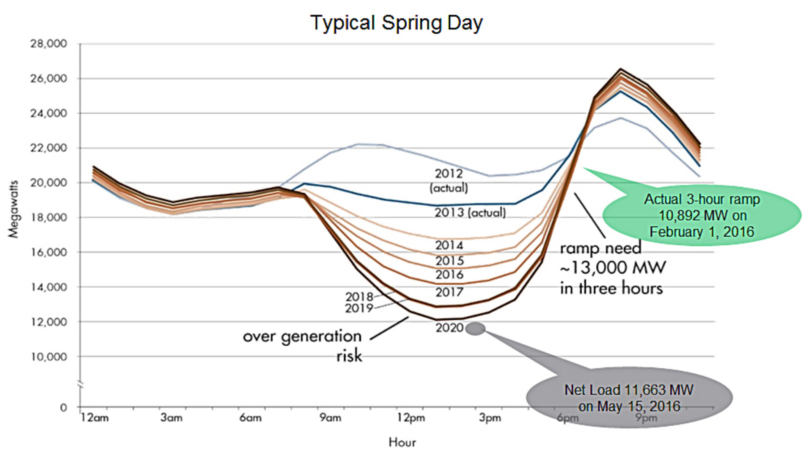
B. Not Every Electric Market has a Capacity Market

Capacity markets are only one way to maintain resource adequacy in power systems. California and Texas each have single-state organized electricity markets. Both, have developed methods for assuring resource adequacy that are independent of FERC capacity market construct. Organized markets, such as MISO, comprised of vertically integrated utilities do not rely on capacity markets as the primary source of revenues compensating generation capital investment cost recovery is primarily through retail rates.

One of the causal events of the California Energy Crisis was the shortage of capacity; in particular, operating reserves. Since that time, the California Public Utilities Commission (CPUC) has assiduously discouraged the creation of any market design that would be regulated by FERC. Instead, it adopted a method by which load-serving entities would forward contract for capacity with suppliers to meet their future capacity needs.[96]

In addition to meeting traditional reserve requirements, California has imple4 demonstrates the impact of customer sided distributed energy on the load served by the CAISO. This figure demonstrates the growing impact that the increased penetration of distributed energy resources has on the daily system load curve. The effect is to greatly increase the need for ramping in evening hours (increasing generation to follow load). The CAISO worked with the CPUC and other local regulatory authorities to meet the challenges associated with the duck curve through the "Flexible Resource Adequacy Criteria and Must-Offer Obligation" (FRACMOO) initiative.

Figure 4: California Duck Curve[97]



96 Pechman, C., "California's Electricity Market: A Post-Crisis Progress Report," California Economic Policy, Public Policy Institute of California, Vol. 3, No.1, January 2007.

97 California ISO, "What the duck curve tells us about managing a green grid," Fast Facts Source, p. 3, https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf. Reproduced with permission.

The Electric Reliability Council of Texas (ERCOT), which operates the Texas electric market, has adopted a modern version of the Peaker Method to help assure generator adequacy.[98] What differentiates this administrative market from the others is that the price is based on operating reserves rather than installed reserves, and is an adjunct to the energy market. As Hogan notes,

> (t)he key connection is with the value of lost load (VoLL) and the probability that the load will be curtailed. Whenever there is involuntary load curtailment and the system has just the minimum amount of contingency operating reserves, then any incremental reserves would correspondingly reduce the load curtailment. Hence, the price of operating reserves should be set at the value of lost load.[99]

The price curve is very much like the construction of the New York Demand Curve. When there is a shortage of operating reserves, the price is equal to an administratively set cost of the value of lost load of $9,000/MWh. Below that, the price is reduced by a formula attenuating the LOLPs. Although the price-making mechanism is theoretically more accurate, it is certainly a more uncertain and volatile investment environment for capacity resources.

C. It's All Getting More Complex

Historically, distribution systems were effectively a pipe from the bulk power system to the customer. Electric flow went in a single direction, carried by transmission from the generator to the distribution system, where it was delivered to customers. Now, power is increasingly bidirectional, flowing from the generator to the customer, but also flowing from the customer through the distribution system back into the high voltage transmission network (the grid).

The changing nature of electric system dynamics, the implications of deploying increasing amounts of distributed energy resources (DERs), new technologies, and evolving models of consumer engagement are putting pressure on the regulatory boundaries that have developed over the last century. Many states have started evaluating regulatory mechanisms to enhance the role of the customer through a variety of different types of proceedings. In New York State, the Reforming the Energy Vision (REV) process started as a broad, statewide industry discussion. The purpose was to:

> establish markets so that customers and third parties can be active participants, to achieve dynamic load management on a system-wide scale, resulting in a more efficient and secure electric system including better utilization of bulk generation and transmission resources. As a result of this market animation, distributed energy resources will become integral tools in the planning, management and operation of the electric system.[100]

As part of that process, the New York Public Service Commission (NYPSC) held multiple technical meetings and open dialogues on the current and potential future state of the New York power system. The NYPSC brought in

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98 Because Texas is isolated from the physical operation of the eastern and western interconnections, and is not considered to be interconnected with other states, its wholesale power transactions are not considered inter-state commerce and are regulated solely by the Texas Public Utility Commission, not FERC.

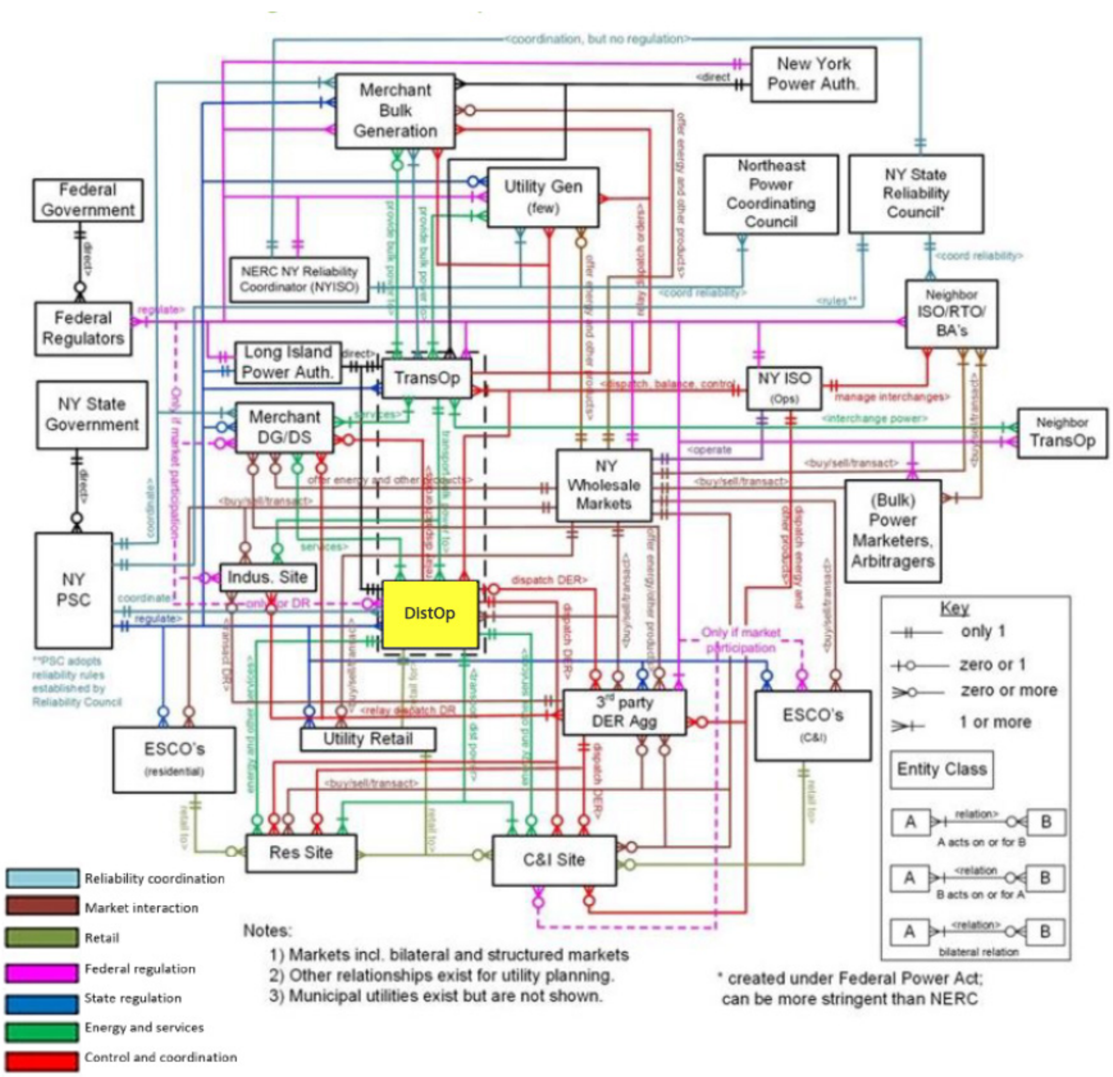
99 Hogan, W., "Electricity Scarcity Pricing Through Operating Reserves: An ERCOT Window of Opportunity," November 1, 2012, https://hepg.hks.harvard.edu/browse/publications?page=14.

100 New York Public Service Commission, "Order Adopting Regulatory Policy Framework and Implementation Plan," known as "Rev Track One Order," issued February 26,2015, Case 14-M-0101, p. 11, https://nyrevconnect.com/rev-briefings/track-one-defining-rev-ecosystem/.

Dr. Jeffrey Taft from the Pacific Northwest National Lab to present a baseline view of the interaction of different regulatory entities in the governance of the New York Power sector. Using a method called grid architecture, in which different levels of the interactions of the grid are visualized and displayed, he created the view of market governance, presented in **Figure 5.**

Embedded in this architectural portrayal of the organization of the New York Power market is an entity called DistOp (Distribution operator — also called distribution system operator (DSO) and Distribution Service Platform Provider (DSPP)), highlighted in yellow. The DistOp is responsible for the physical delivery of power and the coordination of distributed energy resources. It will play an increasingly important role in the future of the electric industry.

Figure 5: Grid Architecture View of Power Market Governance and Operation in New York[101]



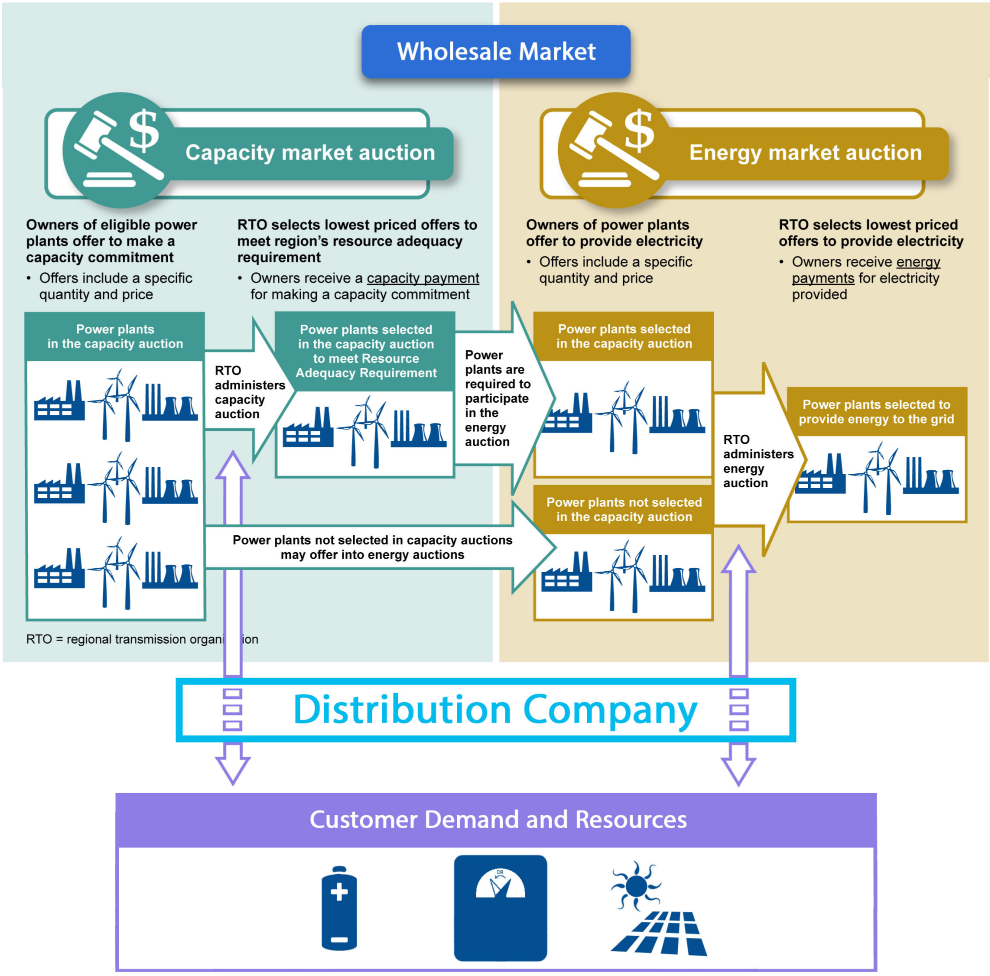
101 U. S. Department of Energy, "Modern Distribution Grid: Vol III: Decision Guide," June 28, 2017, p. 71, https://www.pnnl.gov/images/pdf_icon_new.gif, see section 4.5.2.1 Architectural Considerations, Figure 24, p. 71.

D. The Evolving Nature of the Pricing Formula

Customer-sided resources present a challenge to FERC's pricing formula. Customer resources will have an effect on the operation of an ISO and the markets that it operates. For the market to be efficient, it must incorporate the role of the customer into both the market and regulatory structure. FERC is now taking steps to do just that, incorporating customer resources into energy and capacity market auctions.

The customer is included in **Figure 6**: a depiction of the FERC magic pricing formula originally included in the GAO's review of FERC's governance of capacity markets. This figure shows the developing relationship of the customer to the magic pricing formula. The original graphic represented a market structure that embodies FERC's pricing formula (the energy and capacity portions of the graphic) as it was in 2015 before the animation of the customers' participation in the market. The customer has been added to the figure along with the distribution company providing the physical delivery of power to and from customers. The expansion of resource options in the market will have important implications for the role of the distribution company that are discussed later in this paper.

Figure 6: FERC's Magic Pricing Formula Including the Role of the Customer[102]



102 Based on graphic in U.S. GAO report, p. 19.

No longer passive consumers, many utility customers are now prosumers who are active market participants. Prosumers participate physically through their local distribution companies, including municipal utilities owned by local government, co-ops owned by their customers, or investor-owned utilities regulated by state public service commissions. Ultimately, the question is what mechanisms will be developed to incorporate the customers' role into the wholesale markets, and how (and by which regulatory commission) will those decisions be made?

The impact of activity on the customer side of the meter, in concert with the growing development of renewable generation grid based assets that are competitively priced with conventional fuel types, pose a growing challenge to FERC's magic formula can continue to support the finding that prices based on that formula are competitive and a suitable proxy for cost-of-service regulation. Karl Hausker points out that although intermittent renewables may be lower cost when measured on a stand-alone - Levelized Cost of Energy Basis (LCOE), their true relative cost to other resources may increase as the market share of intermittent resources increases. The reason is that the true cost of renewables is a function of the way in which they are dispatched and the cost of integrating those renewables. Future competitiveness will depend on trends in integration costs and of course trends in other zero- and low-carbon resources.[103]

FERC has taken steps to enable customer resources to participate in wholesale markets through a series of orders:

5) Order Nos. 719 and 745 established the requirement that ISO/RTOs[104] accept bids from demand response resources, and established rules for pricing accepted offers;
6) Order No. 841 covered the incorporation of storage resources into the wholesale market; and
7) Order No. 2222 (the most recent) addressed participation of DER aggregators in the wholesale markets.[105]

Order No. 719 was the first in a series of FERC orders to provide solutions to the barriers that blocked customer resources from participating in the organized (wholesale) markets. In Order 719, FERC found that the active participation of demand response helps increase competition in those markets. It required RTOs and ISOs to accept bids from Aggregated Retail Customers (ARCs) from demand response resources to provide ancillary services[106] (to be used in ISO).[107] Then, in Order 745, FERC found an equivalence in the value of demand response and generation, and thus determined that "paying demand response resources the LMP[108] will compensate those resources in a manner that reflects the marginal value of the resource to each RTO and ISO."[109] In doing so, FERC created an

103 Hausker, K., "Betting on Climate Solutions: Why we should spread our chips," Kleinman Center for Energy Policy, May 2019, https://kleinmanenergy.upenn.edu/paper/betting-climate-solutions.

104 RTOs are regional transmission organizations that operate the transmission system. In contrast, ISO's or Independent System Operate the electric system. The seven organized markets are both ISOs and RTOs. In general, the term ISO will be used, unless as in this case, the term RTO is included in a direct quote.

105 FERC case numbering is not sequential or necessarily in any chronological order. Staff working on cases work to come up with a "snappy" number like Order 888, which was the street number of FERC's new office building at the time the order was released. Order No. 1000 issued in 2017, 18 years after Order No. 2000, which issued in 1999.

106 These include energy imbalance, spinning reserves, supplemental reserves, reactive supply and voltage control, and regulation and frequency response.

107 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719-A, FERC Stats. & Regs. 31,292, at ¶ 49 (2009)

108 LMP is the Locational Marginal Price set by the marginal cost of the incremental resource serving customers' load requirements.

109 *Demand Response Compensation in Organized Wholesale Energy Markets,* Order No. 745, 76 FR 16658-01, at ¶ 47 (March 24, 2011).

important policy that established criteria for just and reasonable rates for compensating customer actions that affect the operation and market. It also established the role of the aggregator as an actor in the wholesale markets. FERC defines the role of aggregators as companies that "generally gather small volumes from various sources, combine them and sell the larger volumes for more favorable prices and terms than would be possible selling the smaller volumes separately."[110] In a following order, related to the role of storage, FERC was concerned "that market rules designed for traditional resources can create barriers to entry for emerging technologies."[111] In essence, the organized wholesale markets had no clear way for storage, particularly behind the meter storage, to participate in the wholesale markets by buying and selling electricity.

The storage order requires each RTO/ISO to create rules reflected in its tariff that would enable participation by storage resources. To do so, FERC ordered the RTO/ISOs to establish a participation model that:

> (A) Ensures that a resource using the participation model for electric storage resources in an independent system operator or regional transmission organization market is eligible to provide all capacity, energy, and ancillary services that it is technically capable of providing;
>
> (B) Ensures that a resource using the participation model for electric storage resources can be dispatched and can set the wholesale market clearing price as both a wholesale seller and wholesale buyer consistent with rules that govern the conditions under which a resource can set the wholesale price;
>
> (C) Accounts for the physical and operational characteristics of electric storage resources through bidding parameters or other means; and
>
> (D) Establishes a minimum size requirement for resources using the participation model for electric storage resources that does not exceed 100 kW.[112]

FERC's most recent order deals with aggregation of distributed energy resources. It was motivated by concerns that ISO rules could create a barrier to entry for emerging or future technologies, potentially precluding them from being eligible to provide all of the capacity, energy, and ancillary services that they are technically capable of providing. The Commission prohibited ISO rules that limit any type of DER technology from participating in the wholesale markets.[113]

These actions both introduce and elevate the role of the aggregator. Under these new orders, an aggregator coordinates retail customer actions to participate in wholesale transactions and is therefore regulated by FERC. **Figure 7** demonstrates how these orders, and presumably those that will follow, are creating a new market structure for controlling, coordinating, and pricing resources.

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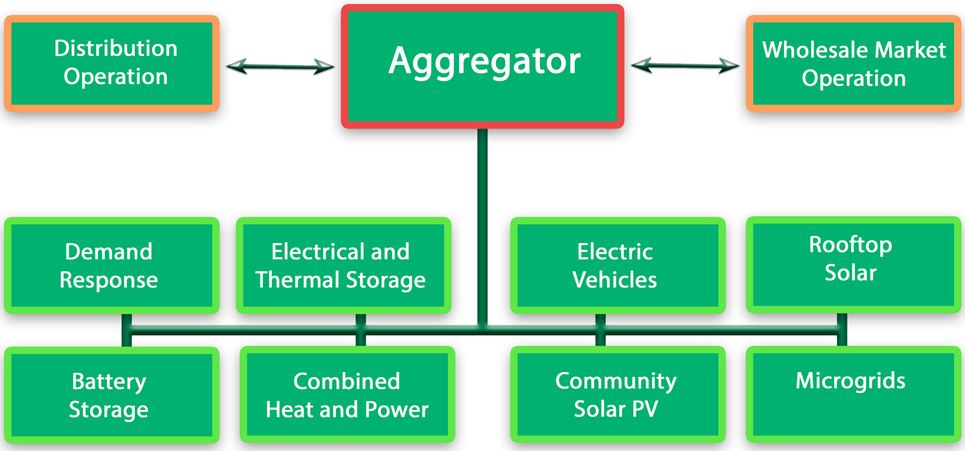
110 FERC, "*Energy Primer: A handbook for Market Basics*, 2020," p. 32, https://www.ferc.gov/sites/default/files/2020-06/energy-primer-2020.pdf.

111 *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127, at page 5, ¶ 10 (2018).

112 *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 841, 162 FERC ¶ 61,127, 2018.

113 *Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 2222, 172 FERC ¶ 61,247 at page 40, ¶ 40 (2020) ("Order No. 2222").

Figure 7: The Role of the Aggregator



There are many outstanding questions introduced by FERC's action. What is the relationship of the aggregator to the distribution operator? Currently, the distribution operator is the local distribution company regulated by the state PUC in the case of investor-owned utilities, municipal government in the case of public power municipalities, and for their member-owners. What authority over aggregators will the PUC's have? Will the customer protection activities of the PUCs be pre-empted? What authority has primacy over operational requirements? FERC's first step in establishing the role of the aggregator is an important beginning, but it is one that raises as many questions as it resolves.

V. The Existential Threat to FERC's Pricing Formula

A. New Technologies Will Disrupt Energy Markets

FERC's pricing formula is on the verge of obsolescence due to the technological revolution in the electric industry. This revolution is the result of renewable innovation and the changing role of the customer, combined with policy mandates to decarbonize electric production. The result has been to increase the types of resources available for providing electric service. The impact has been to fundamentally change the nature of the cost of electric supply.

The revised graphic (**Figure 6**) from the GAO review of capacity markets provides a basis for visualizing the impact of the technological revolution on FERC pricing formula.[114] There are two critical consequences. The first is that the bulk of renewable generation coming online has zero marginal cost, thereby changing the nature of the energy market auction. [115] The second is that customers, as prosumers, change the capacity requirements of electric systems.

As discussed previously, economic dispatch is based on creating a bid stack that establishes the merit order of generation used to meet customer demand. In the early electric industry, this order was based on relative generator unit efficiency. A major advance in dispatch was the incorporation of fuel prices into the station loading slide rule. Since that time, the dispatch process has become increasingly complex, transforming from a cost basis to a bid basis

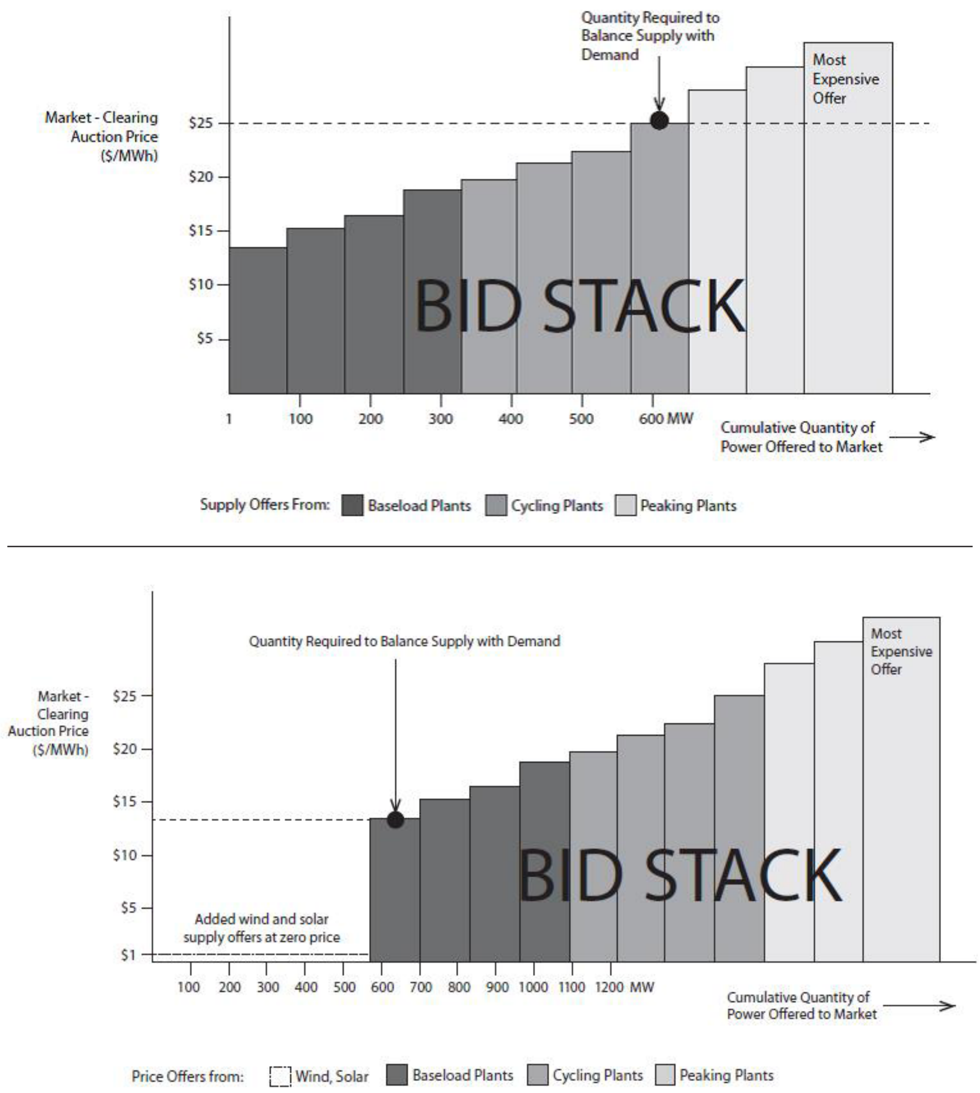
114 GAO, p. 18.

115 The marginal cost is actually negative when power is produced by wind resources that receive a production tax subsidy that pays 2.3 cents per kwh produced for the first 10 years of production.

and covering larger geographic areas with increasing numbers of participants. Despite that advancement, the basic theory of dispatch has not changed since the early 1930's, when it was first formulated by Steinberg and Smith.[116] At its core, that theory is based on minimizing the cost of power, given the relative operating costs of different types of generation, while at the same time maintaining system reliability.

Renewable power creates a problem for economic dispatch. Renewables largely eliminate the relative price of generation used to establish the merit order. They do so, because the marginal cost of production from renewable generation is zero. **Figure 8** illustrates the impact of renewables on the bid-stack. In this illustration, the renewables shift the conventional portion of the supply curve to the right, resulting in a lower market clearing price.

Figure 8: The Impact of Renewables on the Energy Bid Stack[117]



116 Steinberg, M.J and Smith, T.H., "The Incremental Loading of Generating Stations," *Electrical Engineering*, October, 1933.

117 Fox-Penner, P., *Power After Carbon*, Harvard University Press, 2020, pp. 290-291. Reproduced with permission of the author.

Economists often think about markets through the lens of different assumptions. There are now a growing number of states that have a 100 percent renewable mandate. Let's assume that these mandates are universally accepted and will be achieved. What does this mean? When these markets achieve the 100 percent renewable mandate the marginal cost of supply across the range of supply is zero, and, therefore, the competitive price of energy in the extreme may also be assumed to be zero. When there is no more capacity available to serve load, the market value of power will be based upon the customers' value of continuing service, i.e., the value of lost load (VoLL). Pricing will follow a bi-modal pattern. During periods of adequate generation, the energy price will approach zero. During periods of shortage, the price will be set at a price cap, presumably at a measure called the scarcity price that is administratively equated to the VoLL.[118]

There are two ways that this type of pricing regime might be implemented. The first is to have customers (or load-serving entities[119] or utilities) bid for power. Their bids would reflect the value that they place on reliability. Doing so will mean that wealthier customers will be able to outbid lower-income customers and have more reliable electric service. This shifts the fundamentals of dispatch from an engineering-economics problem to an economic equity issue. It also threatens a universal tenet of regulation — universal service at nondiscriminatory rates. The second way is to establish administrative levels of the VoLL to establish price caps. This is the way in which the Texas PUC (TPUC) has implemented the Operating Reserve Demand Curve (ORDC). After a review of various studies that looked at customers' valuation of reliability and an analysis of how high the ORDC needed to be to enable revenue adequacy for generators, the TPUC established the VoLL at $9,000/MWh.[120] During periods of shortage, when the VoLL sets the market price cap, the revenues associated with prices based on shortage costs are socialized, meaning the cost is spread across all customers.

During periods of adequate capacity, generators will not be able to earn the infra-marginal rents that are needed to pay for the capital costs of the generation (or storage) installation. Therefore, capital cost recovery from energy markets will occur only during times of scarcity. But, if the reason for the shortage is weather related, either a drop in wind or lower solar generation due to increased cloud cover, the local renewable generator will not be able to earn scarcity rents because its level of generation will have dropped. In the event that the renewables are located remotely and not affected by local weather (as with off-shore wind), they can earn scarcity rents.

Given the current magic pricing formula, the path to ensure revenue adequacy for the generation required to maintain reliability would be to increase capacity payments or rely more heavily on scarcity pricing. This is what Paul Joskow predicts:

> If we expect to rely on the standard RTO/ISO decentralized wholesale market model, scarcity pricing and/or capacity pricing will have to be a much more important source of revenues to cover the investment costs of solar, wind, dispatchable generation for ramping and ancillary services, and storage.[121]

118 Scarcity pricing allows a shift from the requirement to cost-based bids by generators to allow the rise in price to an administratively determined value of scarcity which is effectively a price cap

119 Load-serving entities (LSEs) are competitive providers of retail services, such as the sale of energy to customers.

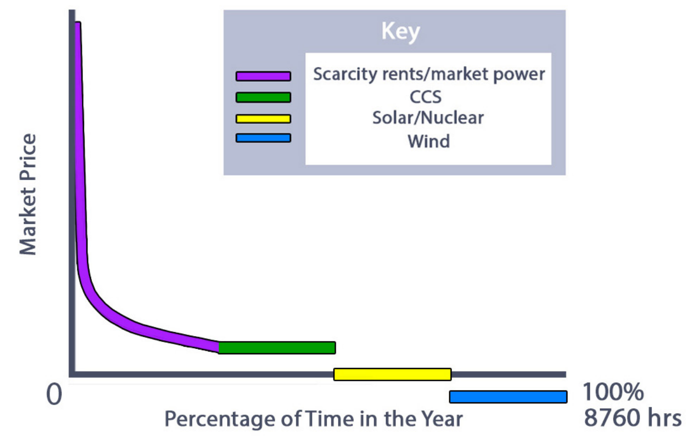
120 Hogan, W., "Electricity Scarcity Pricing Through Operating Reserves: An ERCOT Window of Opportunity," November 1, 2012, https://scholar.harvard.edu/whogan/files/hogan_ordc_110112r.pdf.

121 Joskow, P., "Challenges for wholesale electricity markets with intermittent renewable generation at scale: the US experience," *Oxford Review of Economic Policy,* Volume 35, Number 2, 2019, p. 305.

The impact of generation pricing issues is not limited to renewables. Powering the United States is a massive undertaking. Although a number of states have decarbonization plans based on 100 percent renewables, others have a target for 100 percent zero carbon generation. Currently, there are two types of non-renewable, zero carbon resources that can be deployed to meet decarbonization goals. The first is nuclear, either continuing to operate existing nuclear plants or creating a new generation of nuclear generators. The second is using a thermal generator that burns fossil fuels and captures the carbon emissions to reinject them into the ground. This is called Carbon Capture and Sequestration (CCS). CCS and nuclear plants are, by nature, quite capital intensive.

It is possible to speculate on what a price duration curve (see Appendix p. 68 for description of a price duration curve) would look like for a zero carbon electric system comprised of renewable generation and CCS, as shown in **Figure 9**. The price duration curve measures the amount of time that a plant receives a price at or below a particular level. There are obviously many uncertainties in developing such a graph; for example, the extent to which new generation with biofuels or coal, and CCS are developed, the future role of nuclear power, impact of storage, demand response, and other new technologies.

Figure 9: Hypothetical Price-duration Curve with CCS and Renewable Generation.



The curve is set based on the amount of time a particular type of unit is on the margin. The lowest prices on the price duration curve are negative as a consequence of wind generation receiving a production tax credit. Because wind receives a subsidy based on production, it is possible for wind generation that has a zero marginal cost to offer to pay to provide power at prices below zero. Without the production tax credit, the generator's offer to supply would presumably be zero, the same amount as would be bid by solar and nuclear power generators. There is a technical issue with respect to determining nuclear's marginal cost. Although there is a cost for nuclear fuel, it is often viewed as a fixed-cost, because refueling is based on a pre-determined schedule and not the level of fuel consumed for production.[122] The technology of Carbon Capture and Storage (CCS) is developing rapidly. If we assume that new generation additions are gas-fired CCS power plants, then they will likely have a very similar price, and the portion of the price duration curve will be relatively flat.[123]

The shape of the scarcity pricing portion of the curve is also hard to predict. Will it be broader than depicted? What resources will be in the steep part of the supply curve hockey stick? How will demand response and storage participate in the market and affect the price duration curve? This ultimately leads to the question of the way in which the cost of generating infrastructure will be recovered. There are many questions, but one thing is sure, this price curve is very different from that supporting the magic pricing formula. The notion of the optimal capacity mix is gone, at least for now. The rules for dispatching power plants over an extensive period of zero price power will need to be

122 Kee, E., "Nuclear Power & Short-Run Marginal Cost," https://nuclear-economics.com/nuclear-power-short-run-marginal-cost/.

123 Over time, CCS will evolve to include other fuel sources as biomass.

developed. The shape of the price duration curve will determine the ability of the generator to recover its costs and earn a profit. Cost recovery for generation and the extent of the missing money problem will be more uncertain and complicated than it is today, with the likely result the growing importance of capacity payments.

B. The Need to Resuscitate Capacity Markets

There are no markets like capacity markets. As a staff member of FERC's Office of Energy Policy and Innovation, I was often asked by one of its directors whether I had ever seen a market in which there was both supplier-side mitigation to deal with the exercise of market power on the part of generators and buyer-side market power mitigation to deal with the exercise of market power on behalf of consumers. I have not. The need to massage market results to meet the Commission's vision results in a structure that is neither efficient nor truly competitive. At their core, capacity markets are administrative constructs that are only called markets, because: (1) they are the vehicle that allowed FERC to shift from cost-of-service regulation to market regulation; and (2) the clearing mechanism, after market mitigation and other rules of participation and bidding are imposed, is based on an auction process. As administrative constructs, capacity markets lack the type of market feedback mechanisms present in true functioning markets. Market outcomes can be affected both by gaming rules and by administrative actions. The increasing use of mitigation rules is an effort by FERC to sculpt a market to fulfill the judicial mandate that competitive markets are an acceptable means of assuring that prices are just and reasonable. As will be explained, FERC's actions both fail to (1) support the public interest in protecting consumers (and therefore cannot be just and reasonable) and (2) contribute to the failure of the magic pricing formula.

Suppliers have a number of ways to manipulate capacity markets. "Pivotal suppliers," are generators required to assure adequate operating capacity. When a merchant generator owns more than one generator in a particular market, this indispensable role gives them market power. Withdrawing capacity from the market provides the ability to raise the market price. Without price caps, the price increase can more than compensate for the lost revenues of the plant that has been withheld from the market. Without price caps, the generator can essentially charge whatever it likes, because in the short-run the demand for power is inelastic. FERC has recognized this as an exercise of market power and has imposed offer caps on pivotal suppliers and penalties on those that withhold capacity to reduce supply and increase prices.[124]

Capacity is a somewhat elusive product. It is not like electricity that performs work. Capacity is the ability to produce electricity when called upon.[125] Unless it is called upon to perform, there is no way to ensure that the capacity is available, as required under the various capacity payment schemes. This gives suppliers another way to manipulate the sanctity of the capacity market; they can simply lie about the availability of resources. To receive capacity payments, a generator or demand response provider is obligated to offer into energy markets (e.g., in ISO-NE generators and demand response providers receiving capacity payments have a Capacity Supply Obligation). Whether the generation or demand response resource is dispatched is largely dependent on its price offer for that generation. FERC has found that some generator owners offered generation into energy markets when they were actually not available.[126]

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124 Potomac Economics, "2019 State of the Market Report for the New York ISO Markets," May 2020, p. 18.

125 Or, in the case of demand response, reduce the level of load that the ISO needs to meet.

126 FERC, "Staff White Paper on Anti-Market Manipulation Enforcement Efforts Ten Years after EPACT 2005," November 2016, pp 31-32.

FERC has found that buyer-side market power is exercised when

> "some market buyers may have an incentive to depress market clearing prices by offering supply at less than a competitive level [because] . . . the reduction in capacity prices across the market participant's entire load achieved by a below-market bid for a new generating resource offsets any losses suffered on the individual new entrant being bid into the market below its true competitive cost."[127]

Concern over the exercise of buyer-side market power was built into the design of the PJM capacity market through the Reliability Pricing Model (RPM). This concern over market power is based on the fact that the cost of adding capacity to the system may be less than the revenue decline from that addition. So, for an entity that either has the power to subsidize entry or has a fiduciary responsibility to buy power to serve load, a reasonable business decision and a cost-effective strategy would be to add capacity that drives down prices. Participants in the PJM stakeholder process developing the RPM recognized the potential price suppressing impact of new resource additions. The RPM market design requires that under certain circumstances offers to sell capacity be raised to a level at or above an administratively specified price based on estimates of the cost of the type of capacity being bid into the market. This system, called the Minimum Offer Pricing Rule (MOPR), is applied to new capacity that has the opportunity to win a multi-year stream of payments in the PJM capacity market. Therefore, the MOPR "mitigates the improper exercise of market power that can occur if a generation resource submits capacity to the auction at a below cost price, suppressing the clearing price."[128]

The PJM is not the only ISO with a MOPR. The NYISO and ISO-NE also have MOPR's. They all share similar implementation characteristics. A critical feature of the operation of the MOPR is the definition of cost. The MOPR construct represents a particularly stilted view of cost. It was based on FERC's magic pricing formula. Generators have argued, and FERC actions have reinforced, the notion that "clearing prices must average out over time to the CONE," which is the modern version of the peaker.[129] Costs, as used in the implementation of the MOPR, were defined to fulfill FERC's expectations of cost, to send a bureaucrat's notion of an appropriate price signal, and not the cost incurred by the entity making the capacity offer. As a consequence:

> (a)ny resource that cost more than the market clearing price—regardless of the environmental, technical, or long-term reliability value it may provide—was considered "uneconomic," any contractual payments for that higher value were considered "subsidies," and any price impacts that the added supply might have on the market were considered "artificial."[130]

The administration of the MOPR in the PJM capacity auctions, as in all of the markets, is quite complex. In PJM, offers by generators are subject to three screens—a conduct screen, an impact screen, and an incentive screen—to determine whether the offers submitted are an exercise of buyer-side market power and ought to be mitigated. Certain types of resources have been exempted from the MOPR, including nuclear, coal, and hydro-electric generation. The MOPR also exempted "any planned resource developed in response to a state regulatory or

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127 *PJM Interconnection, L.L.C.*, 137 FERC ¶ 61,145, at P 24 (2011).

128 NextEra Energy Resources v. F.E.R.C., 898 F.3d 14, 18 (D.C. Cir 2018).

129 *Midwest Indep. Transmission Sys. Operator, Inc.*, 153 F.E.R.C. ¶ 61,229 at P 29 (2015).

130 Morrison, J., "Capacity Markets: A Path Back to Resource Adequacy," *Energy Law Journal*, Vol 37, No. 1 (2016), p. 10. 18-1-60-Morrison_FINAL.pdf (eba-net.org).

legislative mandate to resolve a projected capacity shortfall."[131]

When a resource fails these screens, it is subject to mitigation. The basic operation of the MOPR is to require that offers from new capacity resources be at or above an administrative floor (the Offer Review Trigger Price - ORTP) established by the ISOs and affirmed by FERC. A resource receiving state subsidies may not bid its incremental cost into the capacity auction if it is below the ORTP. The effect is twofold. The first is to increase the offer price, which ultimately increases the market price of capacity and customers' rates across the board. The second is to reduce the probability that the resource receiving the state subsidies will receive capacity payments, particularly during periods of excess capacity, since this administratively imposed higher bid might not clear in the auction. This is because FERC-mandated offer price is set at the cost of new entry, a price that is likely above what the market clearing price would be during periods of excess capacity. In this case, FERC policy effectively mandates that a resource receiving a state-sanctioned subsidy will submit a losing bid.

The MOPR has acted as a tool to thwart state policy. At first, restrictions were relatively narrow. Recently, however, these restrictions have become extremely aggressive, and all to support the sanctity of the capacity market administrative construct and price signal. FERC's restriction of state policy began in response to states pursuing generation that they believed was necessary to maintain reliability for their citizens.

In 2011, New Jersey and Maryland became concerned that the RPM was not producing sufficient capacity additions to support reliable service to their citizens. New Jersey enacted the "Long-Term Capacity Agreement and Pilot Program" (LCAPP) to respond to an "energy deficit" resulting from the inadequacy of the RPM to develop sufficient additions in generation capacity.[132] Maryland issued a RFP for generation capacity after the PJM abandoned a transmission project that it had initially indicated was needed for reliability.

After the New Jersey LCAPP was enacted, an association of PJM power providers known as P3 submitted a complaint to FERC stating that the MOPR in place was an ineffective tool for mitigating buyer-side market power. P3 urged the Commission to eliminate the MOPR exemption for state-mandated resources, claiming that "without effective mitigation, the exercise of buyer market power will sound the death knell of competitive markets."[133] The complaint led to the PJM refining and resubmitting its tariff for approval by the Commission. Ultimately, "FERC declined to accord states an opportunity to justify their initiatives on policy grounds, instead removing the state exemption and requiring them to submit cost-based offers like other entrants or suffer the consequences of mitigation."[134]

The price mechanism that New Jersey and Maryland used to support the addition of generation that they believed was needed for reliability is called "contracts for differences." Implementation of this mechanism required the state's LSEs to enter into a contract with a new gas generator, to make up any shortfall between the contract price and the capacity market clearing price. If the clearing price is above the contract price, the generator pays the LSEs the difference. This mechanism provides long-term financial stability for the new gas plant, while providing limitations on the total revenues that they can collect. In response to P3's complaint, FERC required that those offer prices be increased.

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131 April 12 order – para 124.

132 2011 N.J. Sess. Law Serv. Ch. 9 (codified at N.J. Stat. Ann. § 48:3-98.2 (2011)).

133 *New Jersey Bd. of Pub. Utilities v. F.E.R.C.,* 744 F.3d 74, 8 (3d Cir. 2014).

134 Id. P. 10.

The Supreme Court decision in Hughes v. Talen Energy Marketing, LLC. supported FERC's decision to thwart state support for these projects because the transaction involved wholesale sales for which FERC has exclusive jurisdiction.[135] The Supreme Court held that the Maryland program (like the New Jersey program) impermissibly intruded on FERC's jurisdiction over wholesale markets, because the contracts were mandatory and required the resource to clear in the capacity market in order to receive compensation under the contract. What is important about the Hughes case is that the price mechanisms were tethered to the wholesale prices, which are FERC jurisdictional.

C. Challenge of Jurisdictional Ambiguity

Congress was respectful of the state's regulatory authority when it passed the FPA in 1935. Congress adopted cooperative federalism to fill the gap between the federal government and the states. Under this approach, the states retain jurisdiction over generation, distribution, and retail sales. The vertical unbundling of utilities, the move to markets, and the changing role of customers, who are now viewed as assets for grid operation have expanded FERC's jurisdiction. Jurisdictional ambiguity is the uncertainty over whether or not state or federal regulatory agencies have authority over particular actions. State and federal regulatory jurisdiction is based on a legislative (state or federal) grant of authority as clarified by the courts. The jurisdictional relationship with regulated entities is determined by the answers to two critical questions: What products/services can it sell and how will it be compensated? For generators with market-based rate authority, this determines their obligation to generate and the market rules under which they will be compensated. For distribution companies, PUC decisions determine whether utilities they can own DER located on customer premises and how they will recover those costs and make a profit. Increasingly, which commission (state or federal) has the authority to regulate different aspects of the electric industry transformation is uncertain. This uncertainty creates a barrier to innovation and hampers the evolution of the electric system.

The Federal Power Act created a "bright line" between federal and state jurisdictions.[136] The rule was simple—state PUCs were responsible for regulating the price, safety, and adequacy of retail service. FERC/FPC regulated wholesale sales in interstate commerce. Retail service was defined as the distribution and sale of power from the utility to the end-user customer. The broad scope of the FPC/FERC's jurisdiction was established by the Supreme Court decision in *Federal Power Commission v. Florida Power & Light Co*.[137] In this case, the court established the principle that any utility connected through other utilities to interstate transmission networks is engaged in interstate commerce and therefore subject to the Federal Power Commission's jurisdiction. In making that finding, the Court relied on a physical test, that once an electron is put on the transmission system, its location in interstate commerce cannot be determined.

During a period of one-way power flow, the delineation between federal and state oversight was straight-forward. However, as explained earlier, the electric system is getting more complex. As Nordhaus notes, the bright line of federal and state regulatory jurisdiction has blurred and become a "hazy bright line."[138] His characterization fits well into the concept of "jurisdictional ambiguity," developed this concept based upon my experience as an economist

135 *Hughes v. Talen Energy Mktg., LLC,* 136 S. Ct. 1288, 194 L. Ed. 2d 414 (2016).

136 The bright line was clarified by the Supreme Court in its decision, *Public Utilities Commission of Rhode Island v. Attleboro Steam & Electric Company,* 273 U.S. 83 (1927).

137 405 U.S. 948, 92 S.Ct. 929.

138 Robert R. Nordhaus, "The Hazy "Bright Line": Defining Federal and State Regulation of Today's Energy Grid," 36 ENERGY L. J. 203, 207 (2015).

involved in the transformation of the electric system away from cost-of-service to market-based regulation in the 1990s. At that time, the authority over bulk power reliability was ambiguous. This lack of clarity over the authority for reliability constrained the exploration of different market design options. The ambiguity was clarified by the Energy Policy Act of 2005 (EPACT 2005), which amended the FPA to create the role of the Electric Reliability Organization (ERO) for North America, subject to oversight by FERC). FERC designated the North American Electric Reliability Council (NERC) as the ERO.

Both state and federal regulatory commissions operate subject to their enabling legislation. EPACT 2005 directed FERC to: (1) take action in wholesale markets that could potentially make it possible for retail customers to participate in them, via aggregators of demand response; and (2) to eliminate "unnecessary barriers to demand response participation in energy, capacity, and ancillary service markets."[139] FERC established the precedent of the comparability of the value of demand response and generation in the economic dispatch of power systems in Order 745. The generators favored a reduction in the market value of demand response to reflect the fact that with an inefficient rate design, a customer that reduces power consumption saves dollars that would pay for the capacity cost of generation. For this reason, the generators' advocates sought to reduce the demand response payment, by the portion of the customers' energy rate that was associated with these capacity payments. In effect, the generator proposal sought to correct state pricing inefficiency with federal action. After FERC rejected that position and the generators—represented by their trade organization, the Electric Power Supply Association (EPSA)—appealed the FERC decision.

The generators' appeal rose to the Supreme Court, where FERC Order 745 was upheld. The Supreme Court ruled against EPSA in *FERC v. EPSA*, reaffirming FERC's authority to set rules for wholesale markets, including compensation for those who participate. The Court was very specific about the nature of the Commission action that it was affirming: "The Rule regulates the price that wholesale purchasers of power pay through the wholesale rate established in auction markets run by wholesale-market operators for a reduction in consumption by demand-response providers."[140] These providers were commercial aggregators of individual customer responses. The effect of the Commission's order was to enable a new business model of aggregators to bring technology on the customers' premises into the wholesale markets.

D. The Impact of FERC Actions on State Determination of the Role of the Utility

Just as the structure of wholesale electric markets has evolved, so must that of the distribution utility business model. A number of state PUCs are investigating the future of the utility business model. They are doing so by evaluating protocols for maintaining resource adequacy, evaluating new methods of distribution planning, and creating pricing programs for electric vehicles and distributed energy resources. State regulation recognizes that new customer-side technologies will provide more value-added services to the bulk (high voltage) electric grid. New customer-side resources will also provide value added services to the distribution network.

The determination of those new consumer-centric markets structures will be made by different entities: the state public utility commissions for investor-owned utilities; the representatives of municipalities for public power utilities;

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139 Section 1252(f), *Energy Policy Act of 2005*, 119 Stat. 594, 966, 16 U.S.C. § 2642 note.

140 Demand response providers aggregate customers who are willing and able to reduce their consumption to participate in the ISO/RTO markets.

and the members of cooperative utilities. There is a wide range of alternative business models from which PUCs may choose to meet the requirements of their states' consumers. Each answers two questions: (1) What will utilities be allowed or required to do? and (2) How will utilities and non-utility providers be compensated for the services that they provide?

Peter Fox-Penner has framed two potential extremes for the structure of the distribution business model that can evolve logically from current market structures: the Smart Integrator model and the Energy Services Utility model. The Smart Integrator is an operator of the distribution grid in much the same way that an ISO operates wholesale power markets. It provides a platform for energy transactions but does not participate in them. The Energy Services Utility shares the basic functions of the Smart Integrator but is also a provider of services. It is an extension of the vertically integrated utility.[141]

One assumption underlying Fox-Penner's analysis is that there will be instances where economies of scale and scope would justify a single entity providing service over a specific area, such as providing cybersecurity for distribution customers. The aggregation on the customer side of the meter is performed digitally, opening new pathways for cyberattack. The introduction of multiple aggregators with direct control over customer resources could potentially exacerbate cybersecurity concerns and costs by providing new sources of entry for attack. FERC's recent actions will enable the aggregators to participate in the wholesale markets.

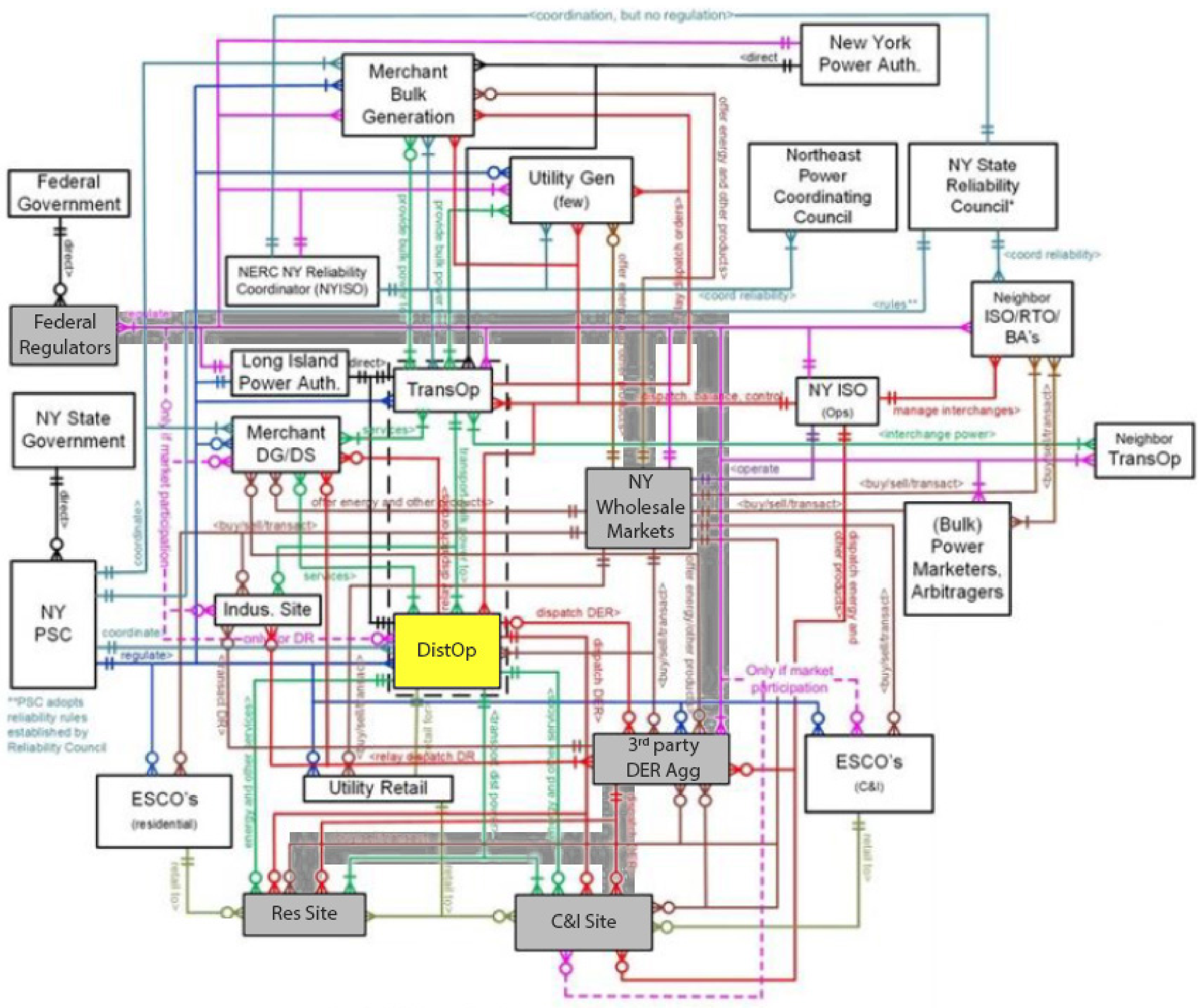
Jurisdictional ambiguity will play an important role in shaping the future of the utility business model and in identifying the types of organizations required for distribution coordination. The federal regulatory environment for incorporating customer-side resources into the operation of wholesale markets has changed. The first in the series of orders related to demand response (Order 745) allowed states to opt out of FERC regulations if the state's vision of how to implement customer engagement in the market differed from that of FERC. Order 745, gave states the power to prohibit DR participation in an ISO's market. FERC's process for including distributed energy resources into the wholesale markets relies on aggregators. States might prefer to have either utilities, state agencies, or the distribution company coordinate customer resources, and initially, FERC was respectful of the states' role.

The federal-state jurisdictional picture changed dramatically in FERC's storage decision, Order 841, which eliminated the opt-out provision in its earlier demand response orders (for all but very small utilities). Based on this order it appears that FERC no longer believes that it is just and reasonable for states to opt out — negating the states' ability to pursue their own vision of how to structure the provision of electricity to their citizens. Efforts by the National Association of Regulatory Utility Commissioners (NARUC) and organizations representing the municipal, cooperative, and investor-owned utilities to overturn the Commission's storage order on jurisdictional grounds were rebuffed by the U.S. Court of Appeals for the DC Circuit.[142] The effect of this decision was to eliminate barriers to entry for different resources while simultaneously creating barriers for states to transform distribution systems to support customer side options.

141 Fox-Penner, P., *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities*, Island Press, 2010.

142 *National Association of Regulatory Utility Commissioners v. F.E.R.C.*, 964 F.3d 1177 (D.C. Cir. 2020).

Figure 10: The Impact of FERC Orders on Market Structure



To visualize the impact of FERC orders, **Figure 10** amends the previous grid architecture view of the governance of the New York market (**Figure 5**). **Figure 10** highlights the effect of FERC's orders. As described previously, DER Order 2222 relies on the role of the aggregator, a new form of market participant in many states, and imposes a new structure on the relation between the distribution utility and its customers. At this point, every state has considered whether to allow retail choice, which allows load-serving entities (LSEs) to sell services to retail customers. Two-thirds of states have decided not to pursue retail choice. This is precisely what an aggregator does. In effect, FERC has bypassed all of the debates that have occurred across the county about who can sell service by creating this new market participant. Further, although commenters proposed that FERC take a proactive step and require ISOs to establish a "coordination framework to address all aspects of coordination (planning, distributed energy resource registration, and operational coordination)," it ultimately encouraged, but did not require, each ISO to develop a coordination framework to address the needs of its region. The reason for such a weak determination is that "the topic of coordination frameworks is still developing and was not fully considered on the record."[143] Many of the issues associated with the coordination framework would be areas traditionally regulated by state PUCs.

States have learned many lessons during the restructuring of the market over the last 30 years. Retail open access that allows customers to shop for electricity from competitive, alternative providers has not always worked out well. California learned the lesson of the potentially crippling impact of market power and manipulation. New York has also learned some painful lessons. Low-income, vulnerable, and uninformed populations are particularly susceptible to unscrupulous behavior. The staff of the NYPSC found that residential customers paid alternative energy suppliers $817 million more than they would have if they had remained with their regulated utility for gas and electric supply.[144]

FERC staff strive to be resource neutral. But FERC culture defines neutral in a narrow way. The internal precept made public in the following tweet by FERC Chairman Chatterjee is "don't put thumb on the scale."[145] For an agency responsible for overseeing systems that rely on physics, it is surprising that it ignores Newton's law of motion, that for every action there is an equal and opposite reaction. FERC's decisions have consequences. Although FERC's mantra is that it does not put its thumb on the scale with respect the choice of resources in markets, the impact of its decisions certainly drives the structure of institutional arrangements. It does put its thumb on the scale in this case. Despite state regulatory commissions, such as the Indiana Utility Regulatory Commission, expressing concern that "distributed energy resource participation must work in tandem with, and not in contravention of Indiana's utility regulatory framework,"[146] a review of Order 2222 reveals no analysis of the impact of its actions on state regulation. In particular, FERC has not evaluated the impact on institutional arrangements that states desire to create to manage the development of customer-sided resources. Ultimately, the dichotomy and focus of state versus federal regulation will affect the choice of resources and have potentially significant environmental impacts. FERC, in its determinations, ordered that each ISO specify in its tariff, "how each RTO/ISO will accommodate and incorporate voluntary relevant electric retail regulatory authority involvement in coordinating the participation of aggregated distributed energy resources in RTO/ISO markets."[147] In establishing both this requirement and the recommendation to establish coordination frameworks, the work will be prepared in a stakeholder process, in which entities that have an interest in the failure of DERs have the ability to hold sway, and those that might be regulated have the unique opportunity to craft the state/federal relationship.

1. Blunt Force Trauma to State Electricity and Environmental Policy

More than 30 years ago, on his departure from the Commission, FERC Commissioner Charles Trabant, in his article "Preemptive Tendencies at FERC," warned of the threat of the effect of expanded preemption of state regulation when it is replaced by a federally designated approach. Trabant's statement that "the only thing that we have to fear is FERC itself"[148] is an apt description of the impact of the changes FERC has caused in these recent jurisdictional orders. Given FERC's recent preemptive posture, his warning was prescient. In an attempt to resuscitate a failed market, FERC has hindered state energy policy.

143 Order No. 2222, 172 FERC ¶ 61,247 at page 94, ¶ 330 (2020).

144 Bruce Alch, Affidavit, *National Energy Marketers Assoc. et al. v New York State Public Service Commission*, Supreme Court of the State of New York, County of Albany, Index No. 05680-16.

145 Neil Chatterjee (@FERCChatterjee), October 7, 2020.

146 Order No. 2222, 172 FERC ¶ 61,247 at page 92, ¶ 320 (2020).

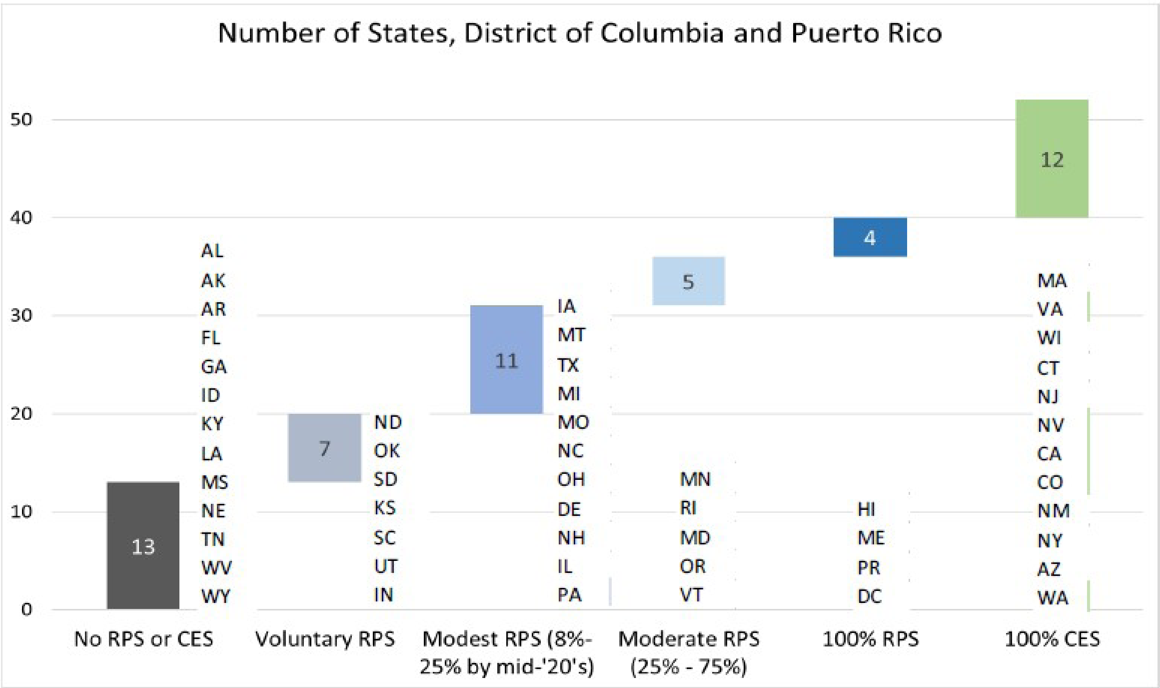
147 Order No. 2222, 172 FERC ¶ 61,247 at page 92, ¶ 322 (2020).

148 Trabant, C.A., "Preemptive Tendencies at FERC: An Insider's View." *Public Utilities Fortnightly*, 1988, p. *29.*

Ironically, FERC now wants customers to pay for these changes in the form of the PJM MOPR. As described by Commissioner Glick in his dissent, the Commission action was about two things, "(d)ramatically increasing the price of capacity in PJM and slowing the region's transition to a clean energy future."[149] Indeed, FERC's majority found that "[a]n expanded MOPR with few or no exceptions, should protect PJM's capacity market from the price-suppressive effects of resources receiving out-of-market support by ensuring that such resources are not able to offer below a competitive price."[150] In doing so, its intent was to "send price signals on which investors and consumers can rely to guide the orderly entry and exit of economically efficient capacity resources."[151] The Commission put its thumb on the scale when its action was to correct for state subsidies but did not do so for federal subsidies. "No single determination in today's order is more arbitrary than the Commission's exclusion of all federal subsidies."[152]

At stake in the MOPR order is the sanctity of state energy and environmental policy. As shown in **Figure 11,** the majority of states have instituted policies to reduce greenhouse gas emissions. Many states have programs such as "renewable energy credits," where renewable resources receive what FERC calls a state subsidy.

Figure 11: State Decarbonization/Renewable Efforts[153]



149 *Calpine Corp., Dynegy Inc., E. Generation, LLC, Homer City Generation, L.P., NRG Power Mktg. LLC, Genon Energy Mgmt., LLC, Carroll Cty. Energy LLC, C.P. Crane LLC, Essential Power, LLC, Essential Power Opp, LLC, Essential Power Rock Springs, LLC, Lakewood Cogeneration, L.P., Gdf Suez Energy Mktg. Na, Inc., Oregon Clean Energy, LLC & Panda Power Generation Infrastructure Fund, LLC v. PJM Interconnection, L.L.C.*, Glick, Commissioner dissenting, 169 FERC ¶ 61,239, 62995 at ¶ 1 (2019). ("MOPR Order").

150 MOPR Order, 169 FERC ¶ 61,239, 62954, at ¶ 5 (2019).

151 MOPR Order, 169 FERC ¶ 61,239, 62963, at ¶ 41 (2019).

152 MOPR Order, Glick, Commissioner dissenting, 169 FERC ¶ 61,239, 63000 at ¶ 27 (2019).

153 Bipartisan Policy Center with analysis by the NorthBridge Group. Reproduced with permission.

The generator campaign to increase prices by negating the impact of renewable resources developed with state support that counterbalanced decades of federal subsidies of conventional fuels began in 2018, with a complaint championed by Calpine, Houston's largest private company[154]

> "Calpine Complainants, filed a complaint … asserting that PJM's Tariff, specifically the MOPR, is unjust and unreasonable because it does not address the effect of subsidized resources on the capacity market. The Calpine Complainants argued that subsidized resources submit bids lower than their true costs to make sure they clear the market, thereby suppressing capacity market prices."[155]

As one of the nation's most sophisticated generators, with a top-notch analytical team guiding their regulatory policy, Calpine clearly understood that if FERC market rules created a fiction that eliminated the impact of state subsidies (such as Renewable Energy Credits) on resources bidding into the capacity markets that it would raise the price it received for selling that capacity. Goggin and Gramlich estimate that the cost of subjecting state-supported generation to PJM's MOPR could reach $5.7 billion a year or a 60 percent increase in the cost of capacity.[156] FERC bought the Calpine argument hook, line, and sinker. In its 2018 response to the Calpine complaint, it made its focus clear—protecting its magic pricing formula; in particular, its administrative construct of capacity markets.

> Over the last few years, the integrity and effectiveness of the capacity market administered by PJM Interconnection, L.L.C. (PJM) have become untenably threatened by out-of-market payments provided or required by certain states for the purpose of supporting the entry or continued operation of preferred generation resources that may not otherwise be able to succeed in a competitive wholesale capacity market.[157]

The 2018 order started the ball rolling on what would become one of the most significant setbacks to energy policy this country has ever experienced. On December 19, 2019, the Commission issued an "Order Establishing Just and Reasonable Rate" that subjects resources supported by state policy to be subject to the MOPR. In effect, like the earlier MOPR discussed earlier, what this action does is require resources to bid at a "replacement rate," which is an administratively determined price for that class of resources. The replacement rate would serve as the minimum offer that a resource with state subsidies could offer its resources into the capacity market. So, for example, if a large box store with significant rooftop solar wanted to participate in the capacity auction, but had received state subsidies for constructing the solar installation, the Commission would require that the box store bid at the administratively determined replacement rate.

FERC's action is a response to state policies actions that "untenably threatened" the integrity and effectiveness of capacity markets. These actions make it more difficult for state-favored generation sources to succeed in wholesale markets. FERC asserted that policies that provided state subsidies to renewable resources in the capacity markets

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154 L.M. Sixel, L.M, "Calpine's Andrew Novotny on fine-tuning to generate every extra megawatt" *Houston Chronicle*, July 27, 2020, https://www.houstonchronicle.com/business/texas-inc/article/Calpine-s-Andrew-Novotny-on-fine-tuning-to-15436619.php.

155 *Calpine Corp. v. PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,239 (2019).

156 Goggin, M. and Gramlich, R., "Consumer Impacts of FERC Interference with State Polices: An Analysis of the PJM Region," *Grid Strategies*, August 2019, p. 2, https://gridprogress.files.wordpress.com/2019/08/consumer-impacts-of-ferc-interference-with-state-policies-an-analysis-of-the-pjm-region.pdf.

157 FERC order rejecting proposed tariff revisions, granting in part and denying in part complaint, and instituting proceeding under Section 206 of the Federal Power Act (issued June 29, 2018), para 1.

"cannot be permitted," calling such state policies "disruptive to competitive wholesale market outcome."[158] Unfortunately, FERC's claim is a syllogism without an analytical foundation. FERC created capacity markets to be competitive; therefore, they must be. The competitiveness of the capacity markets has never been subject to open question or hearings by FERC.

Dismissing stakeholder concerns, FERC took a narrow view:

> There continue to be stark divisions among stakeholders about various issues that we cannot resolve on this record. Instead, we concentrate on the core problem presented in the Calpine complaint and in PJM's April 2018 rate proposal—that is, the manner in which subsidized resources distort prices in a capacity market that relies on competitive auctions to set just and reasonable rates.[159]

In his dissent, Commissioner Glick observed that:

> In its rush to block the impacts of state policies, the Commission ignores the consequences its actions will have on well-established business models. In particular, today's order threatens the viability, as currently constituted, of (1) aggregated demand response providers; (2) public power; and (3) resources financed in part through sales of voluntary renewable energy credits.[160]

Both the National Rural Electric Cooperative Association (NRECA) and the American Public Power Association (APPA) expressed concern that FERC's changes to the MOPR undermine the structure of their members' business models. Delia Patterson, of the APPA, commented that "FERC has definitely gone off the deep end on this. It feels like a devastating, existential threat" to municipal utilities.[161]

The MOPR order reflects a clear abandonment of FERC's customer protection role. Again, as stated by Commissioner Glick in his dissent, "[t]oday's order will likely cost consumers 2.4 billion dollars per year initially, even under conservative assumptions."[162] Commissioner Glick pointed out that the Commission "did not consider what was knowable in reaching its decision, saying the Commission, however, did not even pretend to consider those costs when establishing the Replacement Rate. "It is hard for me to imagine a more careless agency action than one that foists a multi-billion-dollar rate hike on customers without even considering, much less justifying, that financial burden."[163]

By propping up the failing construct of PJM capacity markets, FERC harms the efficiency of the overall electric market. Its action bifurcates the wholesale and retail portions of the industry at a critical time when there is a compelling need for these two portions of the market to become more integrated. What is particularly peculiar about FERC's action is that the approach taken for mitigating the impact of state public policy programs in PJM is effectively the opposite of its approach in New England. In the case of the New England ISO, the Commission approved a market design "to

158 MOPR Order, 169 FERC ¶ 61,239, 62954, at ¶ 5 (2019).

159 Id.

160 MOPR Order, Glick, Commissioner dissenting, 169 FERC ¶ 61,239, 63003, at ¶ 36 (2019).

161 Kuckro, R., 'Off the deep end.' Utility groups blast FERC order" *E&E News*, January 7, 2020, https://www.eenews.net/stories/1062013387.

162 MOPR Order, Glick, Commissioner dissenting, 169 FERC ¶ 61,239, 63006, at ¶ 50 (2019).

163 MOPR Order, Glick, Commissioner dissenting, 169 FERC ¶ 61,239, 63007, at ¶ 54 (2019).

facilitate the transfer of capacity supply obligations from existing capacity resources, which commit to permanently exit ISO-NE's wholesale markets, to new state-supported resources … ."[164] Although the New England mechanism is a bit of a Rube Goldberg creation, it is designed to accommodate state renewable policy. Given FERC's mission statement of efficient markets, its action in the PJM MOPR raises the obvious question of how it can be efficient to accommodate state renewable programs in one market but not to accommodate them in another. Because it addresses issues in the Section 205 proceedings as individual silos, this question has not been asked or answered by the Commission.

Although FERC has a laser focus on its role of eliminating barriers to entry for different resources and creating perfect markets, it does so with blinders on. FERC does not appear to consider how its actions create barriers to the states' ability to regulate customer based grid options. These actions will have a profound effect on existing and evolving business models.

The problem with FERC's actions is not the removal of barriers; doing so is a good thing. The issue is the importance of understanding the implications of removing those barriers and the need to coordinate with the states. In 2017, FERC held a technical conference to investigate the ways in which the states and FERC could coordinate. In a statement supporting the investigation, FERC Commissioner Collette Honorable observed, "(t)he Commission's whack-a-mole response to … state action is inefficient and prolongs uncertainty."[165]

FERC recognized that there were an array of methods that could be used to foster cooperation:

> "At one end of the spectrum, state policies would be satisfied through the wholesale energy and capacity markets. At the other end of the spectrum, state policies would be achieved outside of the wholesale markets, and the wholesale markets would be designed to avoid conflict with those state policies. There are numerous alternatives between these two ends of the spectrum. As part of this discussion, Commission staff seeks to understand the pros and cons of the various alternatives in the Eastern RTOs/ISOs. In the end, Commission staff seeks to understand the potential for sustainable wholesale market designs that both preserve the benefits of regional markets and respect state policies."[166]

To attempt to resolve these issues, FERC held a two-day conference with a wide representation of stakeholders involved in wholesale markets. However, there was no outcome or follow-through from the technical conference. Indeed, at this point, FERC seems to have abandoned any intention of working cooperatively with the states. Unless FERC changes course, the result will be increased litigation and challenges, as opposed to working to develop creative solutions through cooperation.

E. A Question of Balance

Without efforts to try to coordinate, the tension between FERC and the states will likely grow. The power is not one sided. The FPA explicitly recognized the role of the states. It extends the jurisdiction to FERC "only to those matters

164 *ISO New England Inc.*, 162 FERC ¶ 61,205, at Page 2, ¶ 1 (2018).

165 Honorable, C., "Statement," Docket No. Ad 17-11, March 3 2017, FERC Accession Number 20170303-4005.

166 *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, LLC*; Notice of Technical Conference, 82 FR 13331 (March 10, 2017), https://www.federalregister.gov/documents/2017/03/10/2017-04719/state-policies-and-wholesale-markets-operated-by-iso-new-england-inc-new-york-independent-system.

which are not subject to regulation by the States."[167] The courts have not only affirmed FERC's regulatory authority but also that of the states. Suedeen Kelly, former chair of the New Mexico Public Service Commission and also a former FERC commissioner, views the relationship as one of balancing.[168] According to Kelly, there are cases on both sides of the balance that both extend the jurisdiction of FERC and protect the jurisdiction of the states.

On the state side:

- *Oneok, Inc. v. LearJet, Inc.*[169] is a case derived from the California Energy Crisis, in which large users of natural gas filed anti-trust claims against gas pipelines, arguing that prices were inflated by price manipulation. The pipelines moved for summary judgement, arguing that the claims were subject to exclusive FERC jurisdiction. The Supreme Court decision written by Justice Breyer created a new test that focused on the target of state law. In this case, the state law focused on general business conduct, and therefore the efforts to preempt on jurisdictional grounds were rejected.[170]
- *EPSA v. Star*[171] and *Coalition for Competitive Electricity v. Zibelman*,[172] both deal with a state's ability to subsidize nuclear power plants in Illinois and New York to reduce greenhouse gas emissions. In these cases, nuclear power received a direct subsidy from the states' zero emission credits (ZECs) to enable nuclear power plants to continue to operate. Arguments were made that the ZEC programs were preempted by the FPA. What made these subsidies unique was that they were straight subsidies and did not involve the operation of the wholesale market. In both cases, the courts upheld the state's right to subsidize when the mechanism did not rely on wholesale market mechanisms.

On FERC's side:

- *Hughes v. Talen Energy Marketing*,[173] was an 8-0 decision by the Supreme Court invalidating the state of Maryland's financial support for building a gas-fired generator. At issue was a subsidy mechanism that was based on a revenue shortfall from capacity markets (a contract for differences) which FERC perceived adversely affected the operation of capacity markets. The basis for invalidating the law was the mandatory nature of the contract — Maryland required LSEs to enter into the contract — and the fact that it required the resource to clear in the capacity market in order to receive the contract payment. The subsidy was "tethered" to the market prices, which means it was changing the rate of compensation. In contrast, the *Star* and *Zibelman* cases were separate from the wholesale market rates and did not interfere with FERC's role in setting the rate.

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167 16 U.S.C. § 824(a)-(b)(1) (2015).

168 Suedeen Kelly, lecture to the NRRI, Regulatory Training Initiative, October 27, 2020, can be viewed at https://youtu.be/b9cvv7CQ_PY.

169 *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 135 S. Ct. 1591, 191 L. Ed. 2d 511 (2015).

170 Hammond, E. "*Response, ONEOK v. Learjet,*" Geo. Wash. L. Rev. Docket (April 28, 2015), http://www.gwlr.org/oneok-v-learjet/.

171 *EPSA v. Star*, 904 F.3d 518 (7th Cir. 2018)

172 *Coalition for Competitive Electricity, Dynergy Inc. v. Zibelman,* 906 F.3d 41 (2d Cir. 2018), cert. denied sub nom. *Elec. Power Supply Association v. Rhodes*, 139 S. Ct. 1547, 203 L. Ed. 2d 712 (2019).

173 *Hughes v. Talen Energy Mktg., LLC*, 136 S. Ct. 1288, 194 L. Ed. 2d 414 (2016).

- *FERC v. Electric Power Supply Association*[174] was a challenge to FERC's rules establishing a pricing mechanism for demand response. The case reaffirmed FERC's authority to establish pricing rules in the wholesale markets designed to eliminate barriers that it saw as resulting in unjust and unreasonable rates.
- *National Association of Regulatory Utility Commissioners (NARUC) v. FERC*[175] is a case about FERC's Order 841 regarding storage resources. NARUC and others petitioned the court to include the types of opt-out provisions that FERC included in Order 719/719-A regarding demand response in Order 841. In particular, the issue was whether FERC had exceeded its jurisdiction by declaring that states could not broadly prohibit storage resources located on the distribution system from participating in the wholesale markets. The court found that Order 841 "solely targets" the way that storage resources participate in wholesale markets and that this it directly affects wholesale rates, so it is within FERC's jurisdiction. The court also found that nothing in Order 841 directly regulates those distribution systems; and that, "States remain equipped with every tool they possessed prior to Order 841 to manage their facilities and systems."[176] But FERC can still forbid that states from prohibiting storage resources on the distribution system from participating in the wholesale markets because that is "simply a restatement of the well-established principles of federal preemption."[177] The court said that "While the FPA creates two separate zones of jurisdiction, the Supremacy Clause creates uneven playing fields."[178] So, if a state were to broadly prohibit storage resources from participating in the wholesale markets that would improperly invade FERC's exclusive domain.[179]

This high-level review indicates that FERC's authority is not boundless. There is need for balancing. The different outcomes of *EPSA v Star* and *Hughes v. Talen* provide guiderails for the states that want to subsidize particular resources. Doing so, however, will not necessarily yield an efficient design mechanism. For this reason, cooperation between FERC and the states is needed to balance jurisdictional authority and enable more creative and potentially lower cost solutions to the challenges facing the electric industry.

VI. A Proposal for Prudent Regulation

The electric industry is at a strategic inflection point. The magic pricing formula relied on by FERC to satisfy its mandate to assure just and reasonable prices is on the path to obsolescence. At a time when utilities and new market entities are developing new business models, it is imperative that FERC also consider new regulatory models. FERC has a vital role to play in the transformation of the electric industry. As former FERC Chairman Norman Bay observes, "Given the overlap between energy and environmental policy, FERC has a critical role in facilitating the U.S. response to climate change." Many of the same actions required to respond to climate change are those that are necessary to accommodate new technologies and modes of providing service. As Chairman Bay continued, "regardless of one's view of climate change, the energy transition is occurring, and the Commission has an important

174 ?/152*F.E.R.C. v, Electric Power Supply Association*, 136 S.Ct. 760, 193 L. Ed. 2d 661 (2016), as revised (Jan. 28, 2016).

175 *National Association of Regulatory Utility Commissioners v. F.E.R.C.,* 964 F.3d 1177 (D.C. Cir. 2020).

176 *Id.* at 1187.

177 *Id.*

178 *Id.*

179 *Id.*

role in managing and facilitating the transition."[180] One aspect of FERC's role in decarbonization and our nation's electricity future is its role in supporting the development of transmission and creating rates that support the efficient utilization of transmission infrastructure. For example, Shah and Gramlich point out, roughly half of the wires are used at less than 25% of their capacity and the FERC has a vital role to play in efficiently utilizing our nation's transmission infrastructure.[181]

The question is whether and how FERC will embrace this expanded role. This section suggests ways in which FERC may do so in a prudent manner.

A. The Concept of Prudent Regulation

There are few metrics for how well a regulatory agency is performing. One way is to use the key standard for the economic regulation of utilities, the "prudence standard." The prudence standard is used to determine whether costs incurred by utilities are recoverable from customers. In practical terms, the prudence standard evaluates whether a decision that supports cost recovery is reasonable, given the information that is known and knowable at the time the decision was made.

The determination of prudence has played an important role in shaping today's utility industry. Between 1981 and 1991, PUCs disallowed $19 billion of "imprudently" incurred capital investment related to power plant construction (primarily nuclear) from ratepayer cost recovery.[182] In present value terms, that is more than $100 billion. More recently, Mississippi Power and Light entered into an agreement with the Mississippi Public Service Commission that disallowed $6.4 billion related to failed technology at the Kemper County Power Plan lignite coal gasification facilities.[183] States take the prudence standard seriously.

Given FERC's role and familiarity with the standard, the prudence standard provides a reasonable metric for its regulatory performance. The question, then, is whether FERC bases its decisions on what is known and knowable. There is at least one example where the courts have found that FERC improperly made decisions to allow the permitting of gas pipelines without an evaluation of its carbon impacts. In that case, the Sierra Club—with other environmental groups—argued that the construction of the pipeline would increase gas consumption (downstream impacts) and, therefore, have a negative environmental impact. The groups argued that this needed to be evaluated as part of an Environmental Impact Statement. The court agreed that FERC had not considered what it was obligated to consider in its deliberation. FERC had chosen to limit what was knowable. Prudence requires that the commission consider the environmental impacts of its actions.

1. Can rates be just and reasonable if climate impacts are ignored?

FERC has failed to address issues related to carbon and greenhouse gas emissions in anything but a cursory manner. At the core of FERC's regulatory powers is the ability to determine just and reasonable rates. How can the prices in

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180 Bay, N. "Setting an Agenda: The Next Decade for the Commission," *EBA Brief*, Fall 2020, Vol. 1, Issue 2. pp 2-3.

181 Shah, J and Gramlich, R., "Utilities aren't rewarded for saving money. FERC now has a chance to fix this. Utility Dive, September 23, 2020."

182 Michael A. Laros, "Prudence Revisited," *Electric Light and Power* 85, no. 4, (2007): 32, http://www.elp.com/articles/print/volume-85/issue-4/sections/finance/prudence-revisited.html.

183 Mississippi Public Service Commission, "Public Service Commission Closes Book on Kemper," News Release, February 6, 2018.

the market be just and reasonable if the market choice of resources and its regulation ignore their effect on climate change?

FERC has already expanded its reach to be concerned about resilience. In many cases, expenditures to improve resilience, such as the cost of raising substations to avoid rising sea levels, is necessitated by climate change. The Commission established a proceeding to:

> develop a common understanding among the Commission, industry and others of what resilience of the bulk power system means and requires; to understand how each regional transmission organization and independent system operator assesses resilience in its geographic footprint; and to use this information to evaluate whether additional Commission action regarding resilience is appropriate. FERC expects to review the additional material promptly.[184]

Reiter, Schneider and Silverman ask, "can rates truly be just and reasonable if the result is a generation mix that makes our coastal cities uninhabitable?"[185] Why is it prudent for FERC to ask the question its role with respect to resilience but not do so with respect to controlling the carbon emissions associated with climate change that drive the need for investment in resiliency?

The simple answer is that it is not.

The Clean Air Act requires the U.S. Environmental Protection Agency to identify through an endangerment finding "air pollution which may reasonably be anticipated to endanger public health or welfare."[186] The EPA has issued an endangerment finding with respect to greenhouse gases:

> The Administrator finds that the current and projected concentrations of the six key well-mixed greenhouse gasses … in the atmosphere threaten the public health and welfare of current and future generations.[187]

Endangerment without mitigation is a market failure. The economics profession has long understood the concept of market failure caused by the failure to incorporate social costs. For example, Alfred Marshall[188] developed the concept of externalities in 1890 and Arthur Pigou[189] provided the solution of taxing externalities to create efficient market outcomes in 1920. Because greenhouse gas emissions endanger public health and welfare, regulated prices that do not reflect or in some way mitigate those externalities cannot be just, nor can FERC's decisions that overturn state actions to mitigate the impact of electric production on climate change.

The question, then, is what ought FERC to do about this conundrum? Should it move to change the just and reasonable standard? Or should it adjust its own thinking about just and reasonable actions? The question is one of significant gravity, and should, at a minimum, be the subject of an open conversation at FERC that can be initiated by

184 FERC, "FERC Initiates New Proceeding on Grid Resilience, Terminates DOE NOPR Proceeding," News Release, January 8, 2018, https://www.ferc.gov/news-events/news/ferc-initiates-new-proceeding-grid-resilience-terminates-doe-nopr-proceeding.

185 Reiter, H. Schneider, J. and Silverman, A., "Restoring Consensus and Balance to FERC's Market Policies," *EBA Brief*, Fall 2020 Vol 1, no 2 pp. 17.

186 Clean Air Act, § 202(a)(1), 42 U.S.C.A. § 7521(a)(1).

187 https://www.epa.gov/ghgemissions/endangerment-and-cause-or-contribute-findings-greenhouse-gases-under-section-202a-clean

188 Marshall, Alfred, *Principles of Economics,* Macmillan, London, 1890.

189 Pigou, Arthur C., *The Economics of Welfare,* London: Macmillan, London, 1920.

a Notice of Inquiry that would provide a forum to address its potential role whether FERC has the statutory authority to change the standard.

2. FERC's market design actions are exempt from environmental review

FERC's power over wholesale market design stems from its ratemaking authority. FERC actions taken under Sections 205 and 206 of the FPA are exempt from environmental review. Orders that deal with pricing carry the following boiler plate statement.

> The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment. We conclude that neither an Environmental Assessment nor an Environmental Impact Statement is required for this final rule under § 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts, and regulations that affect rates, charges, classifications, and services.[190]

The rules of procedure that excuse FERC from performing an Environmental Impact Statement (EIS) were written at a time in which FERC's pricing actions did not have a significant impact on the choice of resources to serve load. As demonstrated by its current actions, FERC's decisions now have a significant effect on the mix of generation resources, potentially creating a significant environmental impact. Through these actions, FERC has been putting its thumb on the scale of market design. Now, the prudent course is to take actions based on an informed understanding of the downstream impacts of its decisions. How the decisions affect the market structure (including the retail opportunities to customers) and how that in turn affects the choice of resources (with different environmental impacts) used to serve customers have consequential environmental impacts.

3. FERC needs to embrace its environmental role

FERC's magic pricing formula and its implementation have tremendous environmental implications. Through the pricing formula, FERC is making decisions that establish which types of resources are allowed on the playing field and the terms for doing so. The environmental impact of the magic pricing formula is therefore significant. FERC has not embraced its environmental role. When required to prepare an environmental analysis, FERC has chosen to downplay greenhouse gas (GHG) impacts. Recently, it did so by deeming that the analysis of upstream environmental impacts was not warranted under its responsibility to prepare the Environmental Impact Statement (EIS) when it granted a license to the Southeast Market Pipelines (SMP). The Southeast project required the construction of three pipelines that would deliver fracked gas to power plants in Florida. The Court of Appeals for the District of Columbia sided with the Sierra Club in finding that FERC's analysis of the environmental impact of a proposed gas pipeline was inadequate.[191] The Court concluded that "the EIS for SMP should have either given a quantitative estimate of the downstream GHG emissions that will result from burning the natural gas that the

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190 Order No. 2222, 172 FERC ¶ 61,247 at page 276, ¶ 369 (2020). Internal citations deleted.

191 Passut, C., "Court Rejects FERC EIS, Orders Another for Trio of Southeast NatGas Pipelines," Natural Gas Intelligence, Daily GPI, August 22, 2017, https://www.naturalgasintel.com/court-rejects-ferc-eis-orders-another-for-trio-of-southeast-natgas-pipelines/.

pipelines will transport, or explained more specifically why it could not have done so."[192]

4. FERC's investigation of GHG has been limited in scope

FERC's investigation of its role in reducing greenhouse gasses to mitigate the impact of climate change has been limited and reactive. A broad coalition of interested parties asked the Commission "to gather a wide range of stakeholders to discuss practical technical and implementation issues that are raised if states or other entities propose to adopt carbon pricing policies in regions with organized wholesale electric energy markets."[193] FERC responded by holding a technical conference.

The conference was significant for what it focused on and for what it did not. In essence, after receiving the petition from interested parties, the conference focused on FERC's magic formula. There was no broad discussion about the implications of carbon concerns on FERC's regulatory structure. In responding to what many consider an existential threat to the planet, FERC called a hearing on how to tweak its formula to reflect the societal goal of decarbonization. It started with the threshold question of whether FERC had authority to respond to RTO requests to take action to address carbon or to initiate such actions, i.e., whether it could tweak its formula. The panel of legal experts agreed that FERC had that authority. While state PUCs were in discussions with the Commission staff about being included on a panel in the conference, "ultimately neither state was chosen to participate."[194]

In response to the interest shown in the technical conference, FERC adopted a policy statement supporting the addition of state developed carbon prices to the algorithms used by the organized wholesale markets. In discussing, this policy statement, then Chairman Chatterjee clarified FERC's role as the umpire judging state policy, "if states taking action on carbon pricing can be accommodated in our markets, then I think we will have done our jobs and done our jobs well."[195] The problem is that correcting real-time prices with an administratively determined carbon price may be insufficient to engender the magnitude of carbon reductions required to meet decarbonization targets. Oto s necessary to look at methods of enabling investment required to meet national goals. The magic pricing formula is not flexible enough to accomplish this. Chaterjee's statement was clear about FERC's narrow approach to decarbonization, "This policy statement is about our reaction to and consideration of proposals filed under FPA section 205 — this is not about actions instituted pursuant to FPA section 206."[196] In the discussion of difference in the nature of deliberative processes under Sections 205 and 206, this means that FERC is now committed to taking a passive role when it comes to issues related to climate change.

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192 *Sierra Club, et al., v. FERC*, United States Court of Appeals, No, 16-1329, August 22, 2017.

193 Preti Flaherty, "FERC carbon pricing conference request," *Energy Policy Update*, April 21, 2020. https://energypolicyupdate.blogspot.com/2020/04/ferc-carbon-pricing-conference-request.html. The coalition was composed of Advanced Energy Economy, the American Council on Renewable Energy, the American Wind Energy Association, Brookfield Renewable, Calpine Corporation, Competitive Power Ventures, Inc., the Electric Power Supply Association, the Independent Power Producers of New York, Inc., LS Power Associates, L.P., the Natural Gas Supply Association, NextEra Energy, Inc., PJM Power Providers Group, R Street Institute, and Vistra Energy Corp.

194 Morehouse, C., "FERC carbon pricing conference shatters attendance records, but where were the state voices?," *Utility Dive*, October 5, 2020, https://www.utilitydive.com/news/ferc-carbon-pricing-conference-shatters-attendance-records-but-where-were/586372/.

195 Morehouse, C., "'The days of FERC being referred to as an obscure agency are over': Chatterjee reflects on chairmanship," *Utility Dive*, November 9, 2020, https://www.utilitydive.com/news/the-days-of-ferc-being-referred-to-as-an-obscure-agency-are-over-chatter/588610/

196 Chatterjee, N., "Remarks of Chairman Neil Chatterjee on FERC Proposed Policy Statement on State-Determined Carbon Pricing in Wholesale Markets," October 15, 2020, https://www.ferc.gov/news-events/news/remarks-chairman-neil-chatterjee-ferc-proposed-policy-statement-state-determined (emphasis in original).

B. FERC has Broad Authority to Expand the Information it Relies on for Deliberation

FERC has some level of discretion as to how well-informed it is when it makes its determinations. FERC makes decisions about the structure, operation, and market price formation based on two provisions of the FPA. FERC's deliberative process differs depending on the provision under which it is acting. The courts have found that Section 205 puts FERC in a "passive and reactive" role,[197] whereas Section 206 puts FERC in a more proactive role.

1. Section 205 defines a passive role for FERC

Regulated utilities, like ISOs/RTOs, may request changes to their tariffs under Section 205 of the FPA. Typically, requests to modify tariffs are the product of stakeholder processes at the ISO/RTO, with specific voting rules providing voice to different stakeholder groups. FERC must judge whether the proposed tariff modification is "just and reasonable." In doing so, it defers to the ISO's proposed balancing of those interests, providing that FERC can conclude that it will result in just and reasonable rates and is consistent with FERC's statutory duties.[198] The Commission receives a final product designed to promote its acceptance. Parties are able to file their objections. It is a paper process, with positions carefully chiseled. Under Section 205, the Commission can accept the proposal and can make only minor modifications.[199] One big issue that FERC has not audited whether these stakeholder processes produce decisions that are in the public interest.

When an issue comes before the Commission under Section 205, the staff and commissioners are restricted by *ex parte* rules from communicating outside of the Commission to clarify the information presented. Many state PUCs have developed *ex parte* rules less restrictive than FERC's, but that still protect the rights of all stakeholders. The concern over *ex parte* communications on the part of the states is no less significant, but the states have developed reporting requirements that have enabled enhanced communications. FERC could increase communication flow by investigating and adopting *ex parte* rules that are less restrictive in terms of allowing communication while still protecting the interests of various market participants.

The Commission now passes judgment on the information that is presented by the ISO, with comments from various parties. As a practical matter, once FERC receives the information, it does not exercise its ability to either hold technical conferences on matters of dispute, or issue data requests for clarification. The Commission practice, therefore limits the extent of what is knowable under Section 205. What it knows is based on how the petitioners frame their request and that of the parties responding to that framing. As a matter of practice, FERC does not exercise independent judgement as to the extent of what is knowable.

A recent study by the R Street Institute evaluated the stakeholder process and developed a simple recommendation for its improvement that would yield prudent regulation. The study recognizes the important role that stakeholders play in ISO/RTO governance, finding that the stakeholder process is a "primary process for the development, amendment and proposal of RTO market rules and tariffs for approval." They observe that "the fact that proposals

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197 *Advanced Energy Management Alliance v. F.E.R.C.*, 860 F.3d 656, 662 (D.C. Cir. 2017).

198 Peskoe, A., "Easing Jurisdictional Tensions by Integrating Public Policy in Wholesale Electricity Markets," *Energy Law Journal*, Vol. 38:1, 2017, p. 15.

199 *NRG Power Marketing, LLC v. F.E.R.C.*, 862 F.3d 108, 115 (D.C. Cir. 2017).

flow through pre-determined pathways does not always guarantee that the proposal is the best option available, nor does it ensure that self-interests have not pushed others' valid concerns aside."[200]

In an example of the limitations of the stakeholder process as a policy tool, PJM filed a tariff change in the aftermath of the 2014-15 Midwest polar vortex that restricted the supply of demand response resources (DRR). This change required DRRs to be available year round, instead of only during the six-month summer peak capability period.[201] Therefore, in order to bid into the PJM capacity auctions as a "Base Capacity Resource" entitled to the full compensation established through the capacity auction process, a resource needed to be available all year or to partner with a resource that would be available during times of year that it wasn't. In response to complaints that this requirement would disqualify summer-only DRR from economic participation in the market, PJM amended its tariff to allow such resources to aggregate with winter resources, such as wind generation, to qualify for year round availability. Further complaints that the amended program effectively disqualified summer-only DRR that could not find a matching winter resource led FERC to open an investigation into the amended tariff.

The stakeholder processes that led to the PJM tariff and amendment failed to account for vitally important DRR participation in PJM. For example, Enwave Chicago LLC operates a chilled water cooling system in the large load center of downtown Chicago. The system provides space cooling service to approximately 100 large buildings in downtown Chicago comprising more than 40 million square feet of interior space. The service can be provided by using electricity to make ice in the nighttime off-peak hours and using that ice during the next day to cool water during the on-peak hours and thus reduce the system's demand for electricity when it is more expensive for PJM to supply. In fact, the system is capable of reducing its summer daytime demand for electricity from about 50 MW to about 5.5 MW in the heart of the Chicago load center. As Enwave pointed out in comments to FERC, the PJM tariff, produced through the stakeholder process, effectively discouraged Enwave from employing its ice making system as a DRR resource that reduces summer peak demand by requiring Enwave to incur the costs of finding a matching winter resource and, if successful, to accept a lower compensation as part of a combined Base Capacity Resource.[202]

The loss of such a DRR resource during the summer peak demand period would be detrimental to all PJM stakeholders. The PJM is a summer peaking system, with its loss of load risk in the summer.[203] There is no electrical basis for requiring a DRR resource to be disqualified if it is a summer only resource. More importantly, the chilled water system is located in a critically important load center (the Chicago business district), given that the DRR located within the load center has more reliability value than remotely located capacity, such as wind resources. PJM has economies of scope that enable it to coordinate a diverse set of resources. Requiring the City of Chicago chilled cooling system to partner with a resource that provides service only during the winter, increases the transaction costs of the acquisition of capacity resources by keeping the chilled cooling system from participating in the market. The only rationale for this requirement is to restrict participation in the market and to increase the price of capacity. Such

200 James, M. et al., "How the RTO Stakeholder Process Affects Market Efficiency," *R Street Policy Study No. 112*, October, 2017, p. 19, https://www.rstreet.org/wp-content/uploads/2017/10/112.pdf.

201 Accounting for resource adequacy defines periods for which capacity will be required. In this case, there are winter and summer capability periods.

202 *Old Dominion Electric Cooperative et al. v. PJM Interconnection, LLC*, Docket EL17-32-000 and AEMA v. PJM Interconnection, LLC Docket EL17-36-000, Motion to Intervene Out-of-Time and Comments of Enwave Chicago, LLC, Affidavit of William Dolan, PE.

203 Falin, T., "PJM Loss of Load Expectation (LOLE) Criterion," Presentation to the SCRSTF Meeting, April 26, 2016, https://www.pjm-eis.com/~/media/committees-groups/task-forces/scrstf/20160426/20160426-item-04-education-lole.ashx.

an outcome provides benefits to some powerful stakeholders participating in the process but is clearly not in the public interest.

The R Street study's recommendation stems from the Commission's guiding principle for stakeholder processes as laid out in Order 719, "that the stakeholder-governance process needs to be responsive to changing conditions and to continue to evolve with the marketplace"[204] It did so by specifying four criteria for responsiveness: (1) inclusiveness; (2) fairness in balancing diverse interests; (3) representation of minority positions; and (4) ongoing responsiveness.[205] There was an initial flurry of activity evaluating the responsiveness of the stakeholder process after the issuance of 719, but then the issue was largely dropped. The complexity of the market and the number of different types of stakeholder interests that will build the electric system of the future have evolved since Order 719 was issued in 2008. The R Street study

> recommend[s] that RTOs create a regular review process of their stakeholder-governance processes that incorporates the four criteria for responsiveness: inclusiveness, fairness in balancing diverse interests, representation of minority positions and ongoing responsiveness.[206]

Taking R Street's recommendation one-step further, this paper recommends that FERC should receive these reports on a regular basis and establish an ombudsman with the technical capability to judge the validity and importance of stakeholder concerns that have been sidelined in the in the stakeholder process.

2. Section 206 supports a proactive approach for FERC

Section 206 is very different from Section 205. Actions taken under Section 206 start with FERC acknowledging that there is an issue that results in either price formation or operating procedures that are not just and reasonable or is unduly discriminatory. FERC then provides a remedy for the infirmity that it has identified.

Under its Section 206 authority, the Commission has many tools for examining a particular question. For example, take the issue of flywheels. Grid scale flywheels are excellent resources for maintaining second to second frequency control. Early innovators in grid scale fly-wheel storage discovered that the pricing method employed by the ISOs did not value speed or accuracy in paying resources that provided responsive generation for frequency regulation. Frequency regulation traditionally had been provided by intermediate generators that did not respond quickly or accurately to system needs. In response to these concerns, FERC issued a Notice of Inquiry that led to a technical conference in which it requested comments on different frameworks that would appropriately value speed and accuracy in payments for frequency regulation. This was followed by a Notice of Proposed Rulemaking (NOPR) that provided stakeholders an opportunity to comment. After this proceeding, the Commission issued an order in which it found:

> …current frequency regulation compensation practices in organized wholesale electricity markets which fail to compensate resources for all of the service they provide as part of that service are unjust, unreasonable, and unduly discriminatory or preferential.[207]

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204 R Street, p. 19

205 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g*, Order No. 719-A, 128 FERC ¶ 61,059, *order on reh'g*, Order No. 719-B, 129 FERC ¶ 61,252 (2009). a 477

206 James, M, Jones, K.B. Krick. A.H and Greane, R, "How the RTO Stakeholder Process Affects Market Efficiency," R Street Policy Study, No. 112, October 2017, https://www.rstreet.org/2017/10/05/how-the-rto-stakeholder-process-affects-market-efficiency.

207 *Frequency Regulation Compensation in the Organized Wholesale Power Markets*, Order No. 755, 137 FERC ¶ 61,064, at page 4, ¶ 15 (2011).

To address this market failure, FERC required RTOs and ISOs to:

> …compensate frequency regulation resources based on the actual service provided, including a capacity payment that includes the marginal unit's opportunity costs and a payment for performance that reflects the quantity of frequency regulation service provided by a resource when the resource is accurately following the dispatch signal.[208]

The Commission has used a wide variety of methods to exercise its power under Section 206, including technical conferences in which various stakeholders answer questions from staff and the Commissioners and comment on Commission proposals (e.g., Notice of Proposed Rulemaking or Notice of Inquiry). In doing so, the Commission developed and required new market mechanisms that improved both the market and operational efficiency of the wholesale power sector.

C. Achieving Economic Efficiency Requires Cooperating with the States

FERC's primary focus as reflected in its mission statement is "Economic Efficiency." As demonstrated in this paper, FERC's notion of economic efficiency is wrapped up in its magic pricing formula. The formula has two parts (energy and capacity). Both components of the formula are now facing existential threats to the coherence of the markets. It would be prudent for FERC to evaluate and search for alternatives. Although these alternatives will largely reside on the prosumers' side of the meter, it is important to respect the role of state PUCs in determining the way that those prosumers interface with the wholesale market.

The U.S. Department of Energy has been supporting technical assistance to state PUCs to develop the regulatory regime needed to enable the role of the customer as prosumer. Distribution planning is focused on developing physical and economic mechanisms to enable more advanced capabilities. **Figure 12** depicts various stages of evolution of the distribution system. The regulatory authority that enables this evolution will be exercised jointly by FERC and state PUCs. As this evolution progresses on the physical and market side, it will also progress on the planning side, with the need for integrated planning (the wholesale power and distribution systems) becoming more apparent. Coherent evolution will be enhanced by cooperation. But, at the wholesale level, planning of resources to serve load is glossed over. FERC has no office that performs or even focuses on comprehensive planning. The message is clear: Markets Good — Planning Bad. The question is then how the states and distribution utilities can even cooperate with the ISOs in planning. A coherent electric futures requires resolving this issue.

To work, the FERC and the states must develop an ongoing working relationship. Rossi pointed out that a

> "(c)oncurrent jurisdiction can serve as the organizing principle for many modern energy transactions, especially as new technologies and new kinds of energy resources are providing value for the energy system. Such an approach can encourage state policy innovation while also allowing federal-agency regulators an expansive role in setting guiding principles …"[209]

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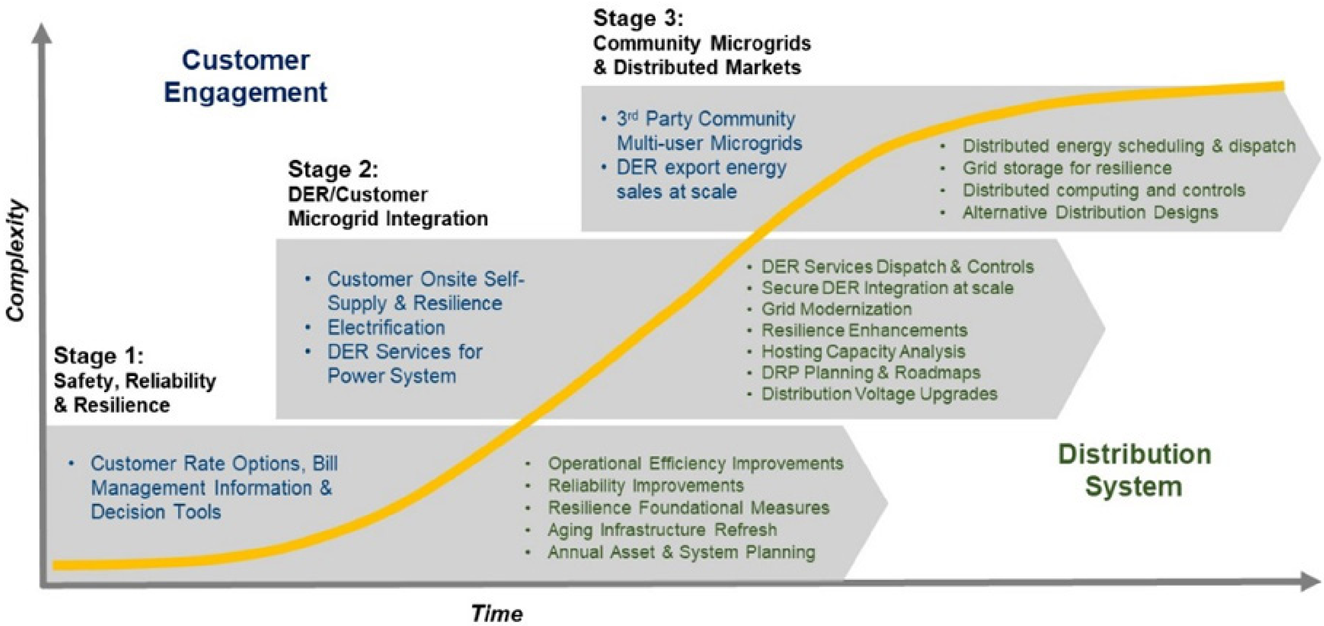
208 *Id* at page 2.

209 Rossi, J., "The Brave New Path of Energy Federalism," *Texas Law Review*, Vo. 95, p. 407.

Figure 12: Distribution Grid Evolution[210]



What that looks like and how it would be implemented requires further discussion. Unfortunately, at this point, the states and FERC are operating independently, with minimal cooperation and interaction.

Everything is in flux. A new model of cooperation needs to be developed. A model of state-federal cooperation, which builds on the structure of federalism in the FPA and sets up a system of dual regulation with separate state and federal spheres is needed. Without cooperation between FERC and the states, the flow of information required to develop an efficient market cannot exist. If FERC finds itself unable to enter into open and frank discussions about the role of regulation in developing the U.S. electric system by ex parte concerns, then the U.S. Department of Energy can use its convening powers to host those discussions. The U.S. DOE has provided technical assistance to the states on modernizing the distribution grid. Whether FERC convenes the discussions or not, the DOE, in conjunction with the National Labs, can provide objective technical information to support those conversations.

The FPC was created to help resolve federal/state conflicts. In 1925, Felix Frankfurter, who later became Justice Frankfurter, and John Landis, who 35 years later, wrote his report to President-elect Kennedy, recognized the growing conflicts between the states and the federal government over the development of the nation's waterways. The relevance of their prescription for resolving federal/state challenges speaks to the issues facing the industry today. Indeed, their solution remains as true today as it was when it was written nearly a hundred years ago:

> The regional characteristic of electric power, as a social and economic fact, must find a counterpart in the effort of law to deal with it. No single State in isolation can wholly deal with the problem. The facts equally exclude the capacity of

210 US DOE, Modern Distribution Grid DSPx: Strategy and Implementation Guidebook" 2020, p. 10, https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid_Volume_IV_v1_0_draft.pdf.

the Federal government to cover the field. Co-ordinated regulation among groups or States, in harmony with the Federal administration over developments on navigable streams and in the public domain, must be the objective.[211]

FERC has tremendous power to cooperate with the states in its enabling statute. The Federal Power Act of 1935 (Sec 209(a)) contained provisions authorizing the Federal Power Commission to establish a joint board to deal with any matter arising in the regulation of companies engaged in interstate commerce.[212] It would seem prudent to begin a discussion with the states about what issues would benefit from such cooperation. It is important that the process be a facilitated discussion among all interested parties, not a directed technical conference. It would be a complex process, a process that is vitally important to succeed. Some questions for consideration include: Could a Joint Board help resolve jurisdictional issues? What processes would such a Board use to enable the cooperation that respects stakeholders' rights? What weight does any finding made by a joint board carry?

D. Time for FERC to Take Stock

At various stages in the life of a regulatory agency, it is time to take stock and to develop a situational awareness of how its decisions and policies will affect the evolution of the industry. It is important for a regulatory agency to review how well it is performing its mission. As noted earlier, FERC has not fulfilled the U.S. GAO recommendation that it review the operation of capacity markets. FERC is frankly not an agency that is long on self-reflection. The administrative structure and team approach to analysis constrains its creativity. To succeed, it needs to understand its strengths and weaknesses and the way in which its role must change to execute its mission as a customer protection agency. Many agencies have adopted different types of practices to align themselves with their missions. Doing so is a pillar of prudent regulation.

The FPC, FERC's predecessor, prepared two significant reports that evaluated the state of the electric system in the United States and have served as a guide to FERC's regulatory actions. These are the National Power Surveys of 1964 and 1970. The Power Surveys were a "multilateral effort, the very undertaking of which has served to improve both communications and understanding between the regulators, the regulated, and those who supply the latter with hardware and services,"[213] The analysis covered wide ranging topics of immediate need, created regional assessments, and prepared long-term forecasts. Given the magnitude of change in the industry, It would be appropriate for the FERC to initiate a new National Power Survey in conjunction with the US DOE, that looks at what is needed to meet decarbonization goals, the role of markets, transmission investment requirements and how to more efficiently use existing transmission, all while paying attention to economic and environmental justice.

The New York Department of Public Service (the staff arm of the New York Public Service Commission) in conjunction with a project team that included staff from the Division of Budget, the Governor's Office of Employee Relations, and an outside management consultant performed an organizational review and self-assessment in 1992. The review was initiated as part of Governor Mario Cuomo's efforts to improve the efficiency and effectiveness of government. The study included two initial surveys of staff that resulted in a response rate of 88 percent. The project team conducted over 300 interviews, 30 focus groups and a number of issue specific surveys to more than 200 staff members. "The

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211 Frankfurter, F., and Landis. J., "The Compact Clause of the Constitution: A Study in Interstate Adjustments," *Yale Law Journal*, 1925, 34, pp. 685-758.

212 Twentieth Century Fund. *Electric Power and Governmental Policy*. Baltimore: Lord Baltimore Press, 1948.

213 Gellman, A., "The Implications of the National Power Survey for the Transportation Industries," *Transportation Research*, Volume 1. 1967, p. 182.

project was viewed as a timely opportunity to examine in a systematic way the many initiatives the DPS has launched and to determine if its current organization is best suited for the challenges of the 1990s and beyond." The goals of the study that are relevant to FERC today included:

- Determine whether the Department's organization structure is best suited to meet changing regulatory responsibilities.
- Determine whether existing staff resources are adequate and properly allocated to the Department's tasks and responsibilities.
- Evaluate whether processes and management methods optimize the efficiency and effectiveness of staff.[214]

Federal agencies have also embraced the concept of reviewing their ability to perform their mission. Quadrennial reviews at the agency level have been developed based upon the Defense Department's 1993 Bottom-up Review (BUR) initiated by Secretary Les Aspin. The purpose of the BUR was to provide a comprehensive review of the nation's defense strategy, force structure, modernization, infrastructure and foundations. Every four years, from 1997 to 2014, the DOD undertook a Quadrennial Defense Review modeled after the BUR that was prepared by the Secretary of Defense in consultation with the Joint Chiefs of Staff.[215] Similarly, the Quadrennial Homeland Security Review is the Department of Homeland Security's strategic document, which is updated every four years as required by law. Each QHSR involves an extensive three-year review process and offers recommendations on long-term strategy and priorities for Homeland Security.[216]

Some Quadrennial Reviews, such as the Quadrennial Veterans Health Administration review, focus on how well the agency is providing service to its clients. In this case, the review provides a strategic plan based on an evaluation of the demand for health services and alternative means of providing those services.[217]

Other quadrennial reviews focus on regulation. The Federal Communication Commission's Quadrennial Review of Media Ownership rules is a self-assessment required by the Telecommunications Act of 1996 to determine whether the Commission's ownership rules remain "necessary in the public interest as the result of competition."[218]

Quadrennial reviews are not only developed by a single agency. The Department of the Interior and the Department of Agriculture work together to present a unified fire management strategic vision for the five federal natural resource management agencies. The focus is on the key mission strategies and core capabilities required to proceed into the future with a common vision and a new collaborative process. This inter- and intra-agency process was designed to ensure continuous programmatic renewal and a focal point for establishing investment priorities.[219]

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214 New York State Advisory Council on State Productivity, "Management Structures Report: Organization Assessment of the Department of Public Service," April, 1992, p. 8.

215 https://history.defense.gov/Historical-Sources/Quadrennial-Defense-Review/.

216 https://www.dhs.gov/quadrennial-homeland-security-review.

217 https://casetext.com/statute/united-states-code/title-38-veterans-benefits/part-v-boards-administrations-and-services/chapter-73-veterans-health-administration-organization-and-functions/subchapter-ii-general-authority-and-administration/section-7330c-quadrennial-veterans-health-administration-review.

218 https://docs.fcc.gov/public/attachments/FCC-18-179A1.pdf.

219 https://www.frames.gov/catalog/1356.

The Department of Energy, in conjunction with the White House, led the development of the Quadrennial Energy Review,[220] which focused on energy infrastructure and government-wide energy policy. What was unique about this effort is that it was performed in conjunction with a complimentary effort, the Quadrennial Technology Review, which examined the status of the science and technology that are the foundation of the U.S. energy system, together with the research, development, demonstration, and deployment opportunities to advance them.[221]

Each of these reviews involves the inclusion of a broad array of stakeholders within and outside of the agency. They are a non-trivial process that requires high level management involvement, but they provide a roadmap defining the challenges and opportunities that the various agencies face in pursuing their statutory mission. They are a way for an agency to proactively plan their future rather than reacting to events before them, in which case they are always trying to play catch-up. FERC would be well-served to perform a Quadrennial Regulatory Review, in which it faces the issues confronting it, and evaluates whether its internal processes are sufficient to yield an equitable and efficient future.

E. Toward a New Pricing Formula

FERC's magic pricing formula is a mechanism for providing electricity at just and reasonable rates. Its ability to do so is strained by the addition of new suppliers in the market and will only continue to be more so. Capacity markets face immediate threats of supplier defection precipitated by the abrogation of state policies. It is prudent for FERC to begin investigating alternative pricing models. An important step in doing so is to put the design of the of future market mechanisms in the context of both regulatory and technical constraints and opportunities. Preparation of a Quadrennial Regulatory Review and a current National Power Survey will assist FERC in developing that understanding.

FERC's magic pricing formula has a short-run focus. A critical step is updating the formula is to expand the time horizon covered by the markets, as well as to ensure coordination with the states.

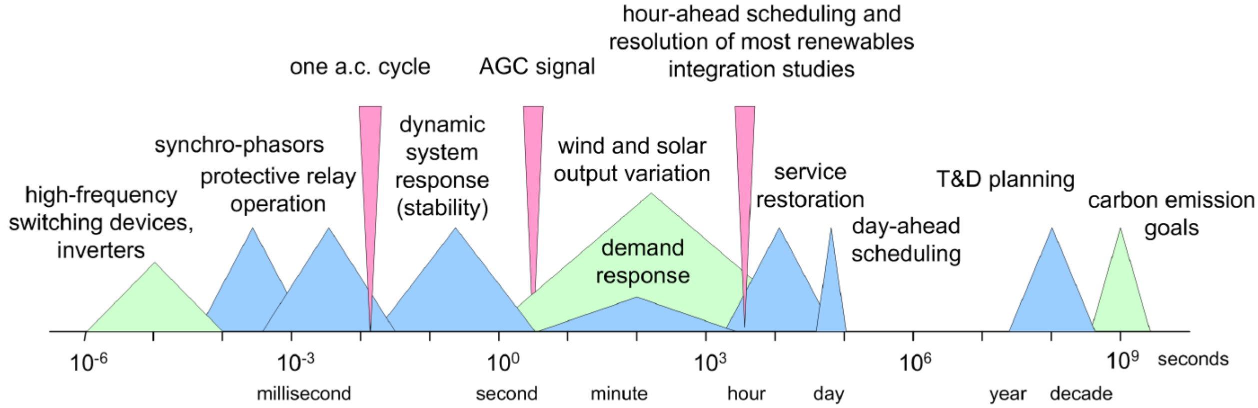
The actions and events required to deliver power to customers occur in a variety of time horizons, from this instant (now, the last instant) in real time to long-run planning. The chronology of these events is portrayed in **Figure 13**. FERC has a short-run focus. The focus of energy markets is even more short-run, from real-time to a day ahead of real-time. Capacity markets either operate within a year, or for several years. Planning to meet carbon goals requires thinking decades out.

State regulation has a much longer time horizon than FERC. State PUCs establish rates on an annual basis and oversee resource adequacy investments that require long-term planning, a time horizon that is consistent with planning for carbon goals.

220 US DOE, "Transforming the Nation's Electricity System: The Second Installment of the Quadrennial Energy Review," January 2017, https://www.energy.gov/sites/prod/files/2017/01/f34/Transforming%20the%20Nation%27s%20Electricity%20System-The%20Second%20Installment%20of%20the%20Quadrennial%20Energy%20Review--%20Full%20Report.pdf

221 https://www.energy.gov/quadrennial-technology-review-2015.

Figure 13: Time Scales in Electric Grid Operation[222]



The objective function underlying the current FERC magic formula was fairly straightforward — to minimize costs subject to reliability constraints. The process of implementing the formula was indifferent to the resources available or the level of pollution they produced. Now, that objective function is changing. FERC has already recognized the importance of resilience and must move to recognize the importance of decarbonization. Doing so, however, will require a rethinking of the pricing formula.

There are a growing number of proposals on the way in which to transform the structure of wholesale markets to accommodate renewables and decarbonization. There are at least three different approaches that have been articulated, with variants within each approach. These approaches are:

1. Bifurcated resource adequacy/energy market construct;
2. A decentralized market approach; and
3. Long-term markets working with short-term energy markets.

Susan Tierney, senior advisor with the Analysis Group, has introduced the concept of a bifurcated market design with the "Resource-Adequacy Construct," which provides assurance of the availability of appropriate and valuable resources installed on the electric system, and the "Energy-Production Construct," which coordinates electric production. This design relies on a "Central Buyer" to procure local and other resources that are needed by electricity consumers for reliable electricity supply. The Central Buyer, a role that can be fulfilled by either an existing or new entity, would rely on targeted solicitations to determine the portfolio of local resources needed to assure a reliable, as well as clean, supply to all customers. Resource-adequacy products (and the activities of load-serving entities (LSEs) and the Central Buyer with respect to resource adequacy) would be regulated by the state PUC. In the Tierney proposal, the ISO/RTO would operate the bulk-power system, with its security-constrained dispatch and wholesale rates for the provision of energy and ancillary services regulated by FERC. Informed by an Integrated Resource Planning (IRP) process (which focuses on clean-energy and climate needs and on LSEs' plans to achieve

222 Alexandra von Meier, University of California, Berkeley, Integration of renewable generation in California: Coordination challenges in time and space, October 2011, https://www.researchgate.net/publication/228854029_Integration_of_renewable_generation_in_California_Coordination_challenges_in_time_and_space. Reproduced with permission.

them in a least-cost way), the state PUC would identify the types of resources that are needed to maintain resource adequacy and the loading order (or preference order) for those different types of resources. The ISO/RTO would use a transparent process to identify the amounts of resources needed for each type of resource adequacy product in each year of the upcoming multi-year (e.g., 3-year or 5-year) period.[223]

Rob Gramlich and Michael Hogan articulate the polar opposite, a decentralized market approach. This market model is largely based on the current ERCOT market in Texas. In this approach there would be a centralized spot market and de-centralized forward procurement between wholesale buyers and sellers. The authors argue that such a market mechanism "puts load-serving entities in the role they should be in—determining and implementing their resource and risk management objectives." They recognize that a "principal challenge" is the credit worthiness of buyers. They suggest that this problem could be resolved by putting public utility commissions in the role of determining the credit worthiness of buyers.[224]

The third approach is more of an integrative approach with long-term markets working in conjunction with short-term markets. This market model provides long-term purchase power agreements (PPA) for desired projects. These contracts rely on customers as a counterparty, as opposed to a more regulated structure. These PPA's act as a backstop to the short-term markets, assuring revenue adequacy. In one example, Corneli proposes a "configuration market" based upon system expansion models to determine how to efficiently incorporate high levels of solar, wind storage, and transmission into the grid. All existing and proposed resource providers (including transmission) would submit bids into the configuration market based on the revenues required to continue operating or, for proposed resources, commit to project development and operation. The configuration computer model would use the various bids in its optimization process to identify a least-cost configuration for the system, both in the short and long run. The configuration model would include not only the standard constraints on delivering safe and adequate service at minimum cost but would also include clean energy objectives.[225] Another version of this approach by Pierpoint builds on renewable portfolio standards and renewable procurement objectives for capital intensive low marginal cost resources. In yet another version of this approach, Gimon envisions that a long-term market might evolve from forward capacity markets.[226]

These three models demonstrate the range and complexity of transforming the current electricity market regimes. There are more models. Each model has different implications for state utility regulators and FERC. The models rely to varying degrees on different types of computer algorithms that can enable different market structures.

It is imperative that FERC participate in a broad conversation about the future of the electric system. Because of its unique role, FERC will be at the center of those conversations and of necessity play an important regulatory role in

223 Tierney, S., "Resource Adequacy and Wholesale Market Structure for a Future Low-Carbon Power System," July 10, 2018, https://www.analysisgroup.com/insights/publishing/resource-adequacy-and-wholesale-market-structure-for-a-future-low-carbon-power-system-in-california/.

224 Gramlich, R., and Hogan, M., "Wholesale Electricity Market Design for Rapid Decarbonization: A Decentralized Markets Approach," in Aggarwal, S. et al., *Wholesale Electricity Market Design for Rapid Decarbonization*, https://energyinnovation.org/wp-content/uploads/2019/07/Wholesale-Electricity-Market-Design-For-Rapid-Decarbonization.pdf June, 2019, p. 24.

225 Corneli, S., 'Efficient markets for High Levels of Variable Renewable Energy," *Oxford Energy Forum*, June 2018: Issue 114, pp. 15-19. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2018/06/OEF-114.pdf.

226 Corneli, S., Gimon, E and Pierpont, B., "Wholesale Electricity Market Design for Rapid Decarbonization: Long-term Markets, Working with Short-term Energy Markets," in Aggarwal, S. et al., *Wholesale Electricity Market Design for Rapid Decarbonization*, https://energyinnovation.org/wp-content/uploads/2019/07/Wholesale-Electricity-Market-Design-For-Rapid-Decarbonization.pdf, June, 2019.

guiding the system to the future. There are many questions — such as how FERC and the states work together to shape the future of the electric system? What alternative pricing systems are available to replace the magic formula? There is no clear path. What is clear, however, is that the first necessary step is to start the conversation.

VII. Recommendations

Given the need to decarbonize, the growing role of electrification, the critical frailty of FERC's magic pricing formula, and the growing and substantial evidence that the current approach will not meet the challenge it faces, it is time for FERC to consider alternatives. To facilitate FERC's efforts to develop a new regulatory paradigm that will both be truly efficient and will enable the decarbonization of the United States, the following actions are recommended:

1. Create an expert panel on emerging technologies to analyze how current market structures limit the adoption of new technologies, and propose alternative market designs that enhance innovation.
2. Evaluate the way that the Commission receives information and determine what enhancements are necessary to enable prudent regulation.
3. Audit the FERC approved and regulated stakeholder governance structure to determine whether it yields efficient results or is an impediment to decarbonization and customer protection.
4. Evaluate the efficacy of capacity markets in compliance with the recommendations made by the U.S. Government Accountability Office.
5. Collaborate with the U.S. Department of Energy to prepare a National Power Survey that maps out the steps required to decarbonize the electric grid including the role of transmission (both new investment and more efficient use of existing infrastructure).
6. Initiate a Quadrennial Regulatory Review process focused on FERC's role in implementing decarbonization policy, customer protection and environmental justice.
7. Create an economics office.
8. Create a stakeholder ombudsman office.
9. Review current management practices to determine if they inhibit regulatory and market innovation, including assessing whether FERC staff is appropriately trained, and whether its culture supports its role as a consumer protection agency.
10. Initiate an open dialogue on the role of carbon and the implications of greenhouse gas reductions on FERC's regulatory scope.
11. Explore methods for working with the states to enhance the efficient transformation of the electric markets to reduce greenhouse gasses.
12. Prepare environmental impact statements on major electric market policy actions that affect the choice of resources used to meet customer demands.
13. Establish an ongoing process and dialogue to investigate market design options that can address methods of decarbonization that assure just and reasonable rates, as well as revenue adequacy for resources supplying the market.

Appendix A—The Peaker Method—the Foundation of FERC's Magic Pricing Formula

The Peaker Method, which is based on the peak load pricing literature,[227] is FERC's magic pricing formula. Although it may have worked in the past, this magic formula is now facing an existential threat because of the proliferation of competitively priced zero marginal cost renewable generation, combined with the animated load that now participates in the operation of the system. To understand why this magic formula is facing an existential threat, it is necessary to understand its building blocks. To do so, we will explain how the four building blocks of this theory work together to create the two categories of cost in the pricing formula: energy and capacity. The building blocks of the magic formula are:

1) the process of economic dispatch;

2) the need for reserves;

3) the idea of an optimal capacity mix; and

4) the peaker as a measure of pure reliability.

The theory behind the Peaker Method provides the theoretical basis for the "missing money" problem in the organized markets regulated by FERC. As will be described in more depth later in this Appendix, a peaker is a generator that is used for peak periods. The peak load pricing literature foreshadows the missing money problem through the insight that in an optimal capacity mix with generators compensated at competitive market prices will have a revenue shortfall equal to the cost of a peaker. As discussed below, changing circumstances are fraying the ability of FERC's magic formula to resolve this shortfall.

A. The Process of Economic Dispatch

At the heart of the magic formula is the economic dispatch process. It is the basis of the energy cost component. The fundamentals of the dispatch process are now being challenged by the combination of renewables and changes in the role of the customer. To understand those changes, it is useful to understand the dispatch process and its role in the magic pricing formula.

Customer usage varies over the course of the day. For any given load-serving entity, and for each organized market, each of its customer's demand is aggregated into what is called load. Load is the demand for power that the system needs to meet (through generation) and is transported (through transmission and distribution) at any given moment. As explained later, electricity is unique in that until the day when storage is widely available and economic, energy must be produced and delivered at the same moment that it is used. System load follows a fairly consistent pattern from day to day and season to season. **Figure A1** provides an example of a daily load pattern and demonstrates that during the course of the day the different types of generation are used to meet customer demand.

227 This problem was first solved by Marcel Boiteux in 1949. See: Boiteux, Marcel P. «La tarification des demandes en pointe: Application de la théorie de la vente au coût marginal», 1949, *Revue générale de l'électricité* This simple model has been further developed, using complex mathematics, into a more realistic stochastic model. The basic conclusions and results are not different in the more complex form. See: "Electricity Pricing and Plant Mix Under Supply and Demand Uncertainty," by Michael Crew and Paul Kleindorfer in *Regulating Reform and Public Utilities,* edited by Michael Crew, Lexington Books, Lexington Mass. 1982. See also Michael Crew and Paul Kleindorfer, "Peak Load Pricing with a Diverse Technology" *Bell Journal of Economics* 7, No. 1 (Spring 1976) pages 207-231., and Chao Hung Po, "Peak Load Pricing and Capacity Planning with Demand and Supply Uncertainty," *Bell Journal of Economics* Vol 14 (1983), pp. 179-190. Also, Michael Crew and Paul Kleindorfer, *Public Utility Economics*, The MacMillan Press Ltd., 1979.

Figure A1: Example of a Daily Load Curve[228]

The process by which an individual utility or operator of an organized market coordinates generating units to meet customers' real-time demand[229] is called economic dispatch. The dispatch problem is a short-run (real-time) economic problem, because all capital is fixed. The objective of economic dispatch is to coordinate a fleet of generation (and, increasingly, customer actions) to keep the lights on and buildings temperate at the lowest possible cost. The long-run problem facing power systems is creating a mechanism or a market for developing the optimal mix and location of resources available to participate in the generation, control, and delivery of power. For a power market that means creating price signals to accomplish that task. The resources used to serve load are now more than just generation; they include physical hardware on the grid that enables the reliable operation of the system, such as storage and demand response, which rely on customer behavior.[230] And, the method of price making needs to enable the success of all resources that will support decarbonization.

The current basis for dispatch, the "incremental method," was developed in the 1930s. At that time, with relatively few generators, all of which had the same fuel cost, a specific utility's problem was to allocate load responsibility (meaning its responsibility to serve the load within its state-granted service territory) to different generating units. The result of this process was to determine the desired level of operating the utility's fleet of generators. Although there were a variety of approaches to schedule generation, the question was which method minimized total generation costs.

228 Modified from, Crew, M. and Kleindorfer, P., *Public Utility Economics*, St. Martin's Press. 1979, p. 163. Used with permission.

229 This requirement that instantaneous generation matches load stems from the basic physics requirement to avoid frequency excursions from causing the electric system to crash.

230 On the customer side of the meter, there are customer ('prosumer') resources that facilitate grid operation, including distributed power generation, power storage, and modifying demand in response to system conditions.

Like automobiles, different types of generating units have different efficiencies (in the case of cars, miles per gallon) over their full range of operation. The efficiency of converting fuel (BTUs) into electricity (kwh) is called the unit's heat rate and is a measure of the incremental efficiency of the generating unit. When the price of fuel is included, marginal efficiency of the unit is translated into the marginal cost of operating the unit. The combination of generating units that would minimize the cost of production (optimality dispatch) occurs when generating units using the same fuel are operated at a level where the incremental thermal efficiency of each generating unit is equal.[231]

Figure A2: The Incremental Cost Slide Rule[232]

Without computers or calculators, mapping the efficiency of each generating unit over its range of operation was a time-consuming calculation. To do so, in 1939, Johnson and Umbenhauer invented the "incremental cost slide rule," pictured with them in **Figure A2**. It was a mechanical device for coordinating power generation. The incremental slide rule was a 36-inch-long wooden frame with slots to accommodate six paper strips—one for each generating unit. The strips contained plots on a logarithmic scale of the station incremental efficiency. It was possible to adjust the strips in the frame to meet load requirements and then read off the relative loading of generating units with the assistance of a horizontal crosshair. An advance in dispatch came with the incorporation of fuel cost to create a relative cost scale. Doing so,the focus of coordination from incremental efficiency to incremental or marginal costs. As load varied over the course of the day, the fleet of generators would be dispatched according to their marginal cost of operation by moving strips of paper on the slide rule. This process produced a 'value stack' that allowed the efficient dispatch of generating units.[233]

In the incremental method, the marginal cost of supplying the next increment of load is the system marginal cost or 'lambda.'[234] It turns out that the system lambda is mathematically equal to a competitive market price. As Alfred Marshall found in 1890, "the more nearly perfect a market is, the stronger is the tendency for the same price to be paid at the same time."[235] This is again similar to a competitive commodity market: each identical grain of wheat has the same price and each identical electron has the same price, and in both cases, competition makes this price equal to the marginal cost of production.

The growth in generator size and transmission interconnections through the 1960s led to increasing levels of inter-utility sales. Inter-utility interchange was appealing, because it reduced the cost of providing service for both the buying and selling utilities. Computer systems were increasingly helping dispatchers operate their systems. Each of the interconnected utilities focused its attention on dispatching generation and power purchases to provide service to their customers and the use of transactions to either displace their own generation that was more costly than what they could purchase, or provided an opportunity to earn sales revenues. Each of these utilities had visibility to what

231 Happ, H.H, *Piecewise Methods and Applications to Power Systems,* New York: Wiley, 19BO.

232 Johnson, H.H., and M. S. Umbenhauer, "An Effective Load Dividing Device," *Edison Electric Bulletin* 7, No. 8 (1939): 385. Permission granted by EEI.

233 Johnson, H.H., and Umbenhauer, M.S., "Station loading slide rule," *Power*, November 1938.

234 It is called lambda for the LaGrangian constraint. The formula for optimal dispatch is to minimize the cost of generation subject to the constraint that the needs of customers are met (the reliability constraint). Lambda, therefore, represents the system marginal cost of an increase in load.

235 Marshall, A., *Principles of Economics*, Porcupine Press; first edition, 1890; eighth edition, 1982; p. 271.

was going on electrically within its own service territory, including both their purchases ('imports') and sales ('exports') but not the system as a whole. However, as the individual utility systems became increasingly interconnected through trade, the impact of what was happening outside of its individual system grew in importance.

The Great Northeast Blackout of 1965 demonstrated the significance of the interconnected nature of the electric system. An incident at Niagara Falls blacked out New York and the Northeast on November 9, 1965. Within 14 minutes of the system disruption, 30 million people in an area covering 80,000 square miles in the United States and Canada were without electricity. In its investigation into the causes of the blackout, the FPC found that the operators of the electrical systems and power plants engulfed in the blackout had "difficulty evaluating the extent of the system disturbance."[236] The inability to monitor the system constrained individual company system operators' ability to respond and adversely affected the ability of the utilities in New York and the Northeast to independently manage the electric system.

The blackout highlighted the increasing complexity of electrical systems and the need for transparency of activity in the interconnected power system. This led to the formation of a number of organizations designed to increase reliability through greater cooperation among the utilities. To a large extent, this increased cooperation has come in the form of information sharing. At the national level, the North American Electric Reliability Council established metrics and standards and collected information about reliability. Within New York, the state's utilities formed the New York Power Pool (NYPP) to coordinate the dispatch and generation of power (which was subsequently transformed into the New York Independent System Operator - NYISO). The New England states formed the New England Power Pool (which was subsequently transformed into the Independent System Operator – New England - ISO-NE). The creation of these power pools formalized the transition from individual utilities supplying customers' needs to a network of companies that share information and coordinate generation and planning on a system wide basis.

Like utility dispatch, these power pools operated on detailed cost data provided by the utilities. This practice continued into the late 1990s, until their transformation from power pools into Independent System Operators (ISOs). The ISOs not only oversee system reliability, but also operate real-time market. Each ISO dispatches the system based on offers made by different providers of generation or demand response. It does so by following the basic principles of the incremental method. **Figure A3** is a photo of the current PJM dispatch control center and demonstrates the complexity of the current dispatch and market system is vastly greater than it was in

Figure A3: PJM Control Center[237]

236 Federal Power Commission, ''Prevention of Power Failures: An Analysis and Recommendations Pertaining to the Northeast Failure and the Reliability of the U.S. Power Systems," 1967, p. 86.

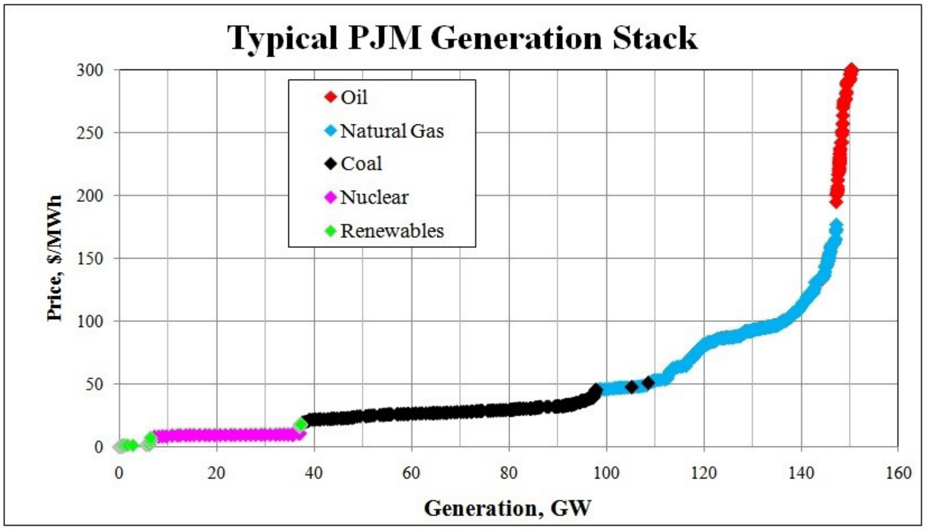
237 Courtesy of PJM.

the days of the station slide rule. The rules and procedures for the operation and pricing of the ISOs, are regulated by FERC.

PJM demonstrates the dramatic evolution of power systems. It had its origin as the Pennsylvania – New Jersey (PNJ) Interconnection, the first power pool in the United States. It was formed in 1927 by Philadelphia Electric, Pennsylvania Power & Light, and Public Service Electric & Gas as a power pool to coordinate the output of the Conowingo Dam on the Susquehanna River. This three-company pool morphed into the PJM Power Pool coordinating generation in the Mid-Atlantic States. The PJM Power Pool is now the PJM Interconnection (hereafter referred to as PJM), the largest wholesale power market in the United States. The PJM now coordinates over 700 member companies with more than 1,300 generation sources, with a capacity of 180,806 MW serving 65 million people across 84,236 miles of transmission lines in an area of 369,098 square miles covering 13 states and the District of Columbia, which produces 20 percent of the U.S. GDP.[238]

FERC's magic pricing formula is implemented by the organized markets, the ISOs. PJM, as well as all of the ISOs regulated by FERC, takes all of this bidding data and creates a merit order that determines the order in which generation is used to meet the real time load requirements of the system. This merit order is the market supply curve (also called the dispatch stack, bid stack, or generation stack), shown in **Figure A4.** Although the physical status of the electric system is evaluated many times a second, generators and customer demand resources are typically dispatched in five-minute increments. All buyers and sellers in the market transact at the cost of meeting a marginal increase in demand, the Locational Marginal Price (LMP), which reflects the marginal cost of serving load at the specific location, given the set of generators that are dispatched and the limitation of the transmission system.[239]

Figure A4: The PJM Supply Curve[240]



238 Ward. M.J., "Resource Commitment and Dispatch in the PJM Wholesale Electricity Market," PJM Presentation, June 28, 2011, and PJM at a Glance, https://www.pjm.com/~/media/about-pjm/newsroom/fact-sheets/pjm-at-a-glance.ashx.

239 FERC, *Energy Market Primer*, 2015, p. 60.

240 Tayari, F., "Fundamentals of Electric Markets," 2020. Reproduced with permission of the author, https://www.e-education.psu.edu/ebf200/node/151.

Power system supply curves often are characterized as "hockey sticks." As the capacity in the system becomes increasingly scarce, the marginal cost of supply increases dramatically. This provides a potential source of market power. The withholding of generation during the California Energy crisis effectively removed capacity, thereby shortening the stick and increasing the amount of time that the market was clearing on its steep portion.

B. The Need for Reserves

The underlying analytic structure supporting the magic pricing formula is based on maintaining system reliability. The second term in the pricing formula is capacity; traditionally, this has meant generation capacity. The need for capacity is determined by both the level of customer demand and the need for reserves. Reserves are system resources used to ensure reliability. The North American Electric Reliability Council defines bulk power electric reliability as "the degree to which the performance of the elements of that system results in power being delivered to consumers within accepted standards and in the amount desired." It does so in two time frames: operation and planning, each with different criteria and measurement. In the short run, "***security*** is the ability of the bulk power electric system to withstand sudden disturbances." In the long run, "**adequacy** is the ability of the bulk power electric system to supply the aggregate electric power and energy requirements of the consumers at all times." There are two types of reserves: *operating*, to respond to real-time failures of generation, and *installed*, to guide investment planning to ensure that operating reserves are available when needed.[241]

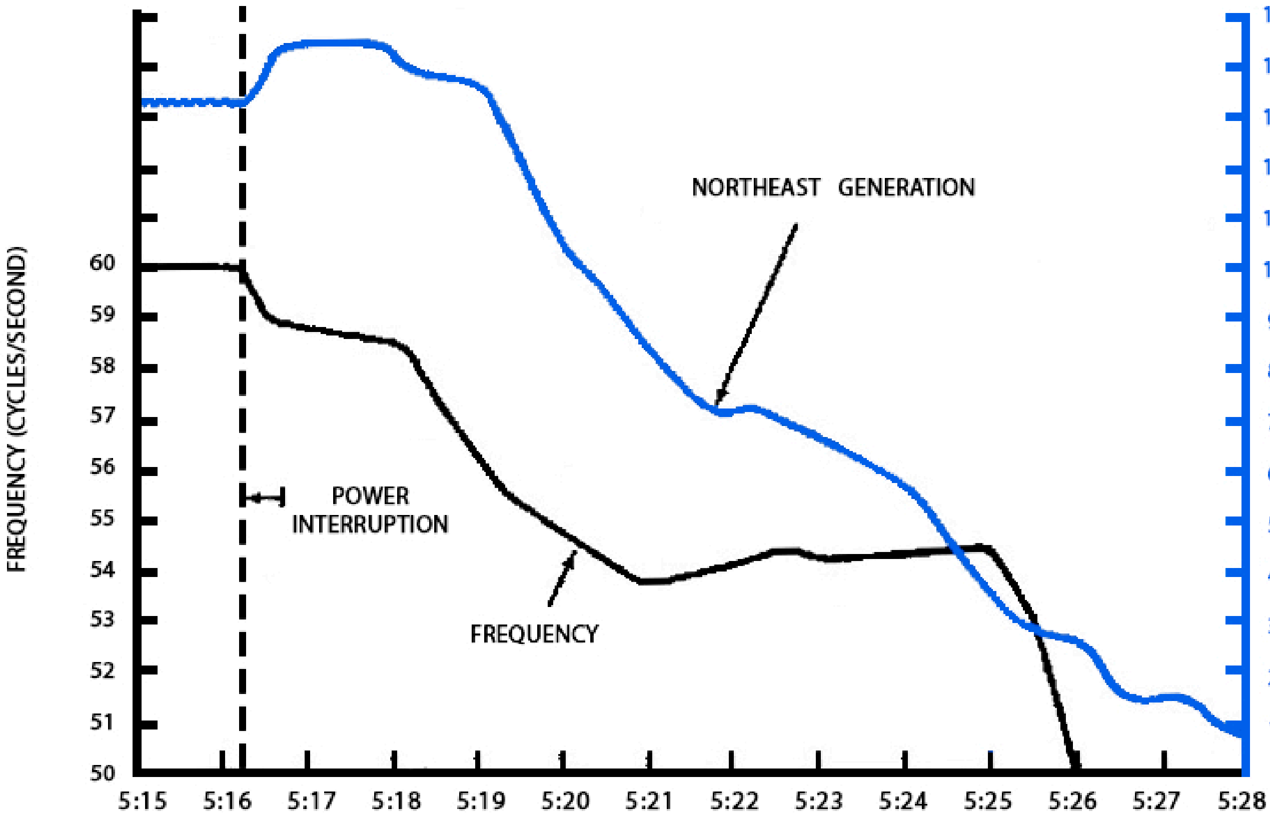
1. Maintaining frequency and the need for operating reserves

As load varies over the course of the day, reserves are needed to maintain frequency when parts of the system fail. One critical constraint on dispatch is the need to keep the system in balance, where the amount of generation is just sufficient to meet customers' instantaneous demand. Electric systems are designed to operate at a given frequency (60 hertz in the United States). To accomplish this, generators are synchronized, all spinning at the same speed so that their aggregate output precisely equals load. If generation is less than load, the system frequency will drop. In response, the generating units control systems called governors will attempt to increase their output to keep the system in balance. If frequency drops too far, other control circuits will disconnect the generator from the system to prevent physical damage to the units which are designed to rotate at 60 cycles per second producing power at 60 Hz.

Although the exact cause of the Great Northeast Blackout of 1965 remains unknown, what is known is that the 2,000 MW of power moving from Ontario to New York instantly stopped flowing. **Figure A5** demonstrates what happened to generation and system frequency in the 14 minutes leading to the blackout. As the system frequency dropped from 60 cycles, more generators separated from the system. The initial response was initiated by "governors" that sensed the drop in frequency and increased output to try to make up for the loss of the 2,000 MW of power. The generator response was insufficient to stabilize the system and return it to normal operating state. What ensued was a vicious cycle of system failure, called a "cascading blackout." With frequency drops resulting in more generation disconnecting from the system and further reducing the frequency of the system, the entire system ceased to operate in a coherent manner, and the Northeast was blacked out.

241 North American Electric: Reliability Council, ''Reliability Concepts," February 1985, p. 8.

Figure A5: Minute-by-Minute deterioration of NE Power System, Leading to System Generation and Frequency Preceding the 1965 Northeast Blackout[242]



Like all complex machines, generators fail.[243] When the system loses a generator or transmission line, it needs operating reserves to inject more energy into the system to maintain the frequency of the system. During the period in which the pricing formula was developed, reserves were provided by "steel in the ground." Today, demand response is increasing in importance an additional source of quick start operating reserves.

The Great Northeast Blackout occurred so quickly that the system operators did not have the time or the awareness to reconfigure the system to reduce the extent of the blackout. In other situations where there was a shortage of capacity, the system did have time to respond. This is precisely what happened during the California Energy Crisis when generation gaming and power withholding contributed to a shortage of capacity. When operating reserves were inadequate, the system shed load in a controlled manner to return to a safe state with adequate operating reserves. Without enough power to maintain the stability of the grid, the California ISO began selectively blacking

242 Modified from: United States, Federal Power Commission, ''Prevention of Power Failures: An Analysis and Recommendations Pertaining to the Northeast Failure and the Reliability of the U.S. Power Systems," 1967.

243 The failure of transmission is electrically equivalent to the failure of generation.

out different parts of the state to protect the electrical integrity of the system. **Figure A6** announces the start of a new regime in the California Energy Crisis, in which rotating blackouts were initiated to maintain reliability.

Figure A6 : Rotating Blackouts to Maintain Reliability[244]

Historically, the objective of operating electric systems was to serve all load at all times. Dropping load was seen as an undesirable last resort. Today, customer behavior is becoming a critical element in ensuring the operation of the electric system. There are a variety of mechanisms that can be used to induce customer response to the need to recalibrate the balance of supply and demand in the system — from real-time pricing, in which the customers respond to market price signals, to demand response, where customers are paid to reduce demand. For example, Alcoa Aluminum is a very large electric user, with 3,000 MW of load in the United States. Alcoa's processes allow it to voluntarily curtail significant load without adversely disrupting production. As a consequence, it is able to provide the Midcontinent Independent System Operator (MISO) with 70 MW of direct load control at all times, plus another 75 MW of operating reserves.[245] By voluntarily curtailing consumption when the system requires reserves, Alcoa is able to benefit by earning revenues from helping to provide stability to the grid.

The rationale behind paying customers to curtail their consumption is that, from an operating perspective, reducing load is equivalent to increasing generation. By integrating the customer into the operation of the system, it is possible to reduce the steel in the ground and lower costs. FERC Order 745 found that demand response was equivalent electrically to generation in balancing the electric system. In doing so, it cited an analysis provided by Alfred Kahn:

> [Demand response] is in all essential respects economically equivalent to supply response … [so] economic efficiency requires … that it should be rewarded with the same LMP that clears the market. Since [demand response] is actually—and not merely metaphorically—equivalent to supply response, economic efficiency requires that it be regarded and rewarded, equivalently, as a resource proffered to system operators, and be treated equivalently to generation in competitive power markets. That is, all resources—energy saved equivalently to energy supplied— … should receive the same market-clearing LMP in remuneration.[246]

To ensure that prices were not discriminatory, FERC mandated that the price paid for voluntary curtailment (demand response) was equal to the market clearing price in the ISO.[247]

Operating reserves fall into the general category of "ancillary services." These services, such as operating reserves, frequency response (the second by second balancing of the system frequency) and "black start" (providing power to restart the system after a blackout) were traditionally provided by vertically integrated utilities. With industry

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244 *San Jose Mercury News.* Reproduced with permission.

245 Todd, D., "Alcoa – Dynamic Demand Response," DOE Workshop October, 2011, https://www1.eere.energy.gov/analysis/pdfs/alcoa_dewayne_todd.pdf.

246 *Demand Response Compensation in Organized Wholesale Energy Markets*, 134 FERC ¶ 61,187, 2011 WL 890975, at page 6, ¶ 20 (Mar. 15, 2011).

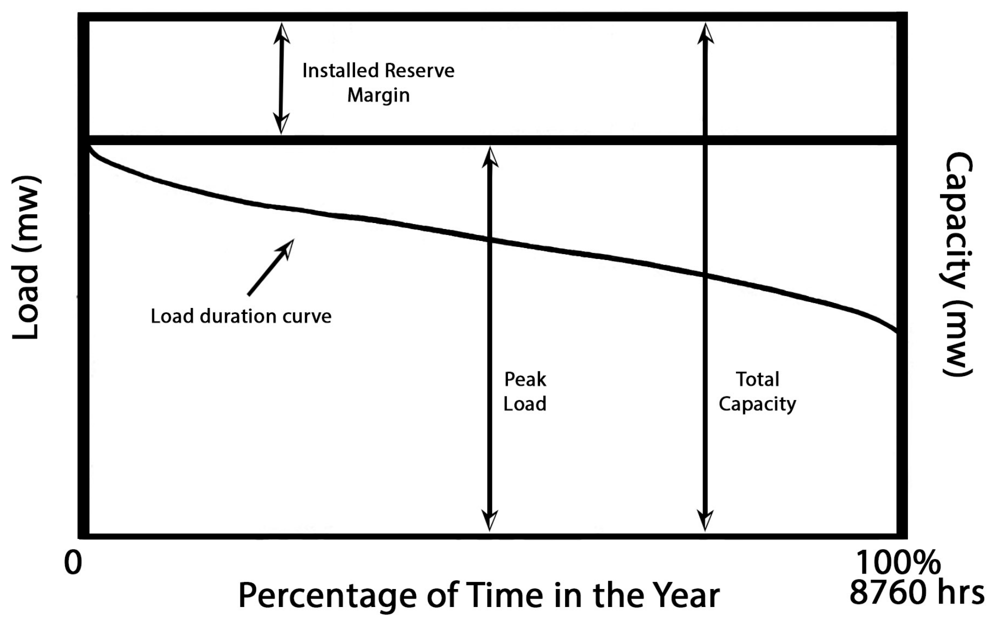
247 *Id*.

restructuring, the services were explicitly turned into products used to operate the system. These services are incorporated into the ISO dispatch system, and for the purpose of this paper are included in the discussion of energy markets.

2. Installed reserves

In contrast to the operating reserves needed to maintain real-time reliability by instantaneously matching supply and demand, installed reserves represent the balancing of supply and demand in the medium to long term, over months and years. Installed reserves are the amount of installed generation above expected peak load required to maintain system reliability given expected levels of generator failure. Electric systems use installed reserve margins as the criteria for how much generation is required to maintain reliability. The reserve margin is the traditional metric used to evaluate the need for additional generation. Therefore, the installed capacity requirement equals generation to meet peak load plus the installed reserve requirement.

Figure A7: Load Duration Curve, the Installed Reserve Margin and Total Capacity



Reserves provide a margin of safety against the failure of the system components. Today, this is generally known as resource adequacy. Generation adequacy is illustrated in **Figure A7** and introduces the load duration curve, which measures the aggregate (non-sequential) pattern of load through the year. Typically, it is interpreted as the amount of time that load is at or above a particular level. The highest point on the curve is the peak load, which occurs only during a very small percentage of time. The reserve margin is a fixed percentage of capacity above the peak load needed to meet installed reserve (resource adequacy) requirements. The load duration curve measures the amount of time that demand is at or above a given level, typically measured over the course of a year. Peak load occurs only for a small fraction of the time during the year.

Installed reserve margins are designed to meet reliability metrics. The most common metric for establishing reserve margins is a called the loss of load probability (LOLP).[248] The LOLP calculation describes the relationship between the expected load and available generating capacity. The determination of available capacity is made through calculations that take into consideration the outage characteristics of generation units based on their historic failure rates. It provides an estimate of the expected number of times that a failure to serve load due to a shortage of generation will occur. In performing the calculation, the physical characteristics of generating units, such as the unit's maximum capability and a long run probability measure of the unit's service availability, are key variables.[249] When Giuseppe Calabrese first developed the LOLP index in 1947,[250] he observed that when the index was evaluated against the performance of electric systems, that systems that had a LOLP[251] of one day in 10 years operated fairly well, and systems that had a higher index tended to have a higher degrees of disruption.[252] As a consequence, the criteria of "one-in-ten" became an industry standard for LOLP. Although the criteria were applied uniformly, there were a wide range of methods used to do so.[253]

The LOLP calculation is still used today to determine the desired level of installed reserves. Installed reserves are used for planning investment in generation.[254] The idea behind installed reserves is to assure that there is sufficient steel in the ground to meet contingencies, such as the failure of generating units. This forms the basis for evaluating what is increasingly referred to as resource adequacy. A major change that has occurred over time is the recognition that customer demand response is a legitimate method for providing reserve capability.

3. Optimal capacity mix

The engineering-economic concept on which the magic pricing formula is based is the optimal capacity mix by Turvey.[255] What is important about that description is the idea that a mix of generation through time minimizes the cost of providing service to customers and the way that costs are recovered for that generation. This section will help us understand that this key pillar of the magic pricing formula is soon to be an anachronism because of the changing nature of the resources used to supply load, undercutting a key pillar of the theory.

Given a forecast of customer demand, there is a mix of different types of generation that would minimize the cost of providing power to meet customers' needs. A critical pillar of the Peaker Method is that load and the cost of generation vary in a predictable manner over the course of the day, season, and year. The different types of

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248 There are a variety of other related metrics including the Loss of Load Expectation (LOLE), Loss of Load Hours (LOLH), and Expected Unserved Energy (EUE).

249 Billinton, R., Ringlee, R.J., and Wood, A.J., *Power Reliability Calculations*, MIT Press, 1973.

250 Calabrese, G., "Generating Reserve Capacity Determined by the Probability Method," *AIEE Transactions*, 1947, 66, pp. 1439-1450.

251 The initial formulation by Calabrese was in terms of the Loss of Load Expectation as it measured the number of expected events. Over time, the term probability has been frequently substituted for expectation. In some instances, people who discuss it in probability terms convert the expectation into a probability measure.

252 Pechman, *Regulating Power: The Economics of Electricity in the Information Age,* Kluwer Academic Publishers, 1993.

253 Billinton, R. "Criteria Used by Canadian Utilities in the Planning and Operation of Generating Capacity." Institute of Electronic and Electrical Engineers, *Transactions on Power Systems,* 1988, 3, pp. 1488-1493.

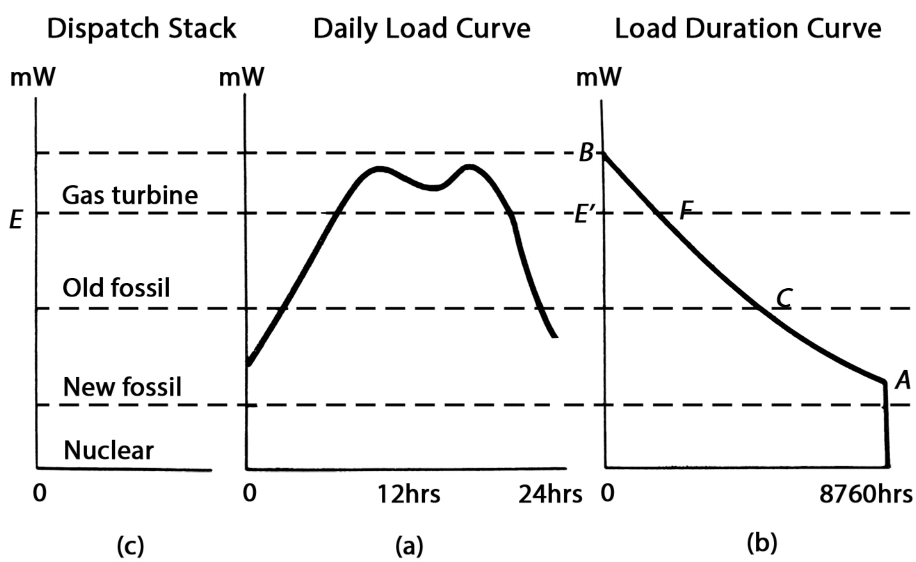
254 The definition is Installed reserve margin at the time FERC was adopting its magic formula is: Installed reserve = (Installed generating capacity –peak load)/peak load.

255 Turvey, R., *Economic Analysis and Public Enterprise*, Rowan and Littlefield, 1971.

generation used to serve that load play a fundamental role in the development of the Peaker Method, so does the shape of the customer demand curve. As described later, the patterns of demand and generation on which the peaker method is based are changing as a result of variable renewable resources (solar and wind), the prospect of storage and the changing role (both through demand response and a change in consumption patterns driven by renewable generation and storage on the customers' premises. These changes have resulted in the existential threat to FERC's magic pricing formula.

To examine the threat to the magic pricing formula, we need to ignore the current state of technology and think about the time when electric systems were built to serve all customer load through conventional generation. At that time, disconnecting customers in order to balance the system in response to a system emergency was not viewed favorably. That is the world in which the Peaker Method, depicted in **Figure A8,** was developed.

Figure A8: Relationship of Dispatch/Bid Stack, Daily Load Curve and Load Duration Curve[256]

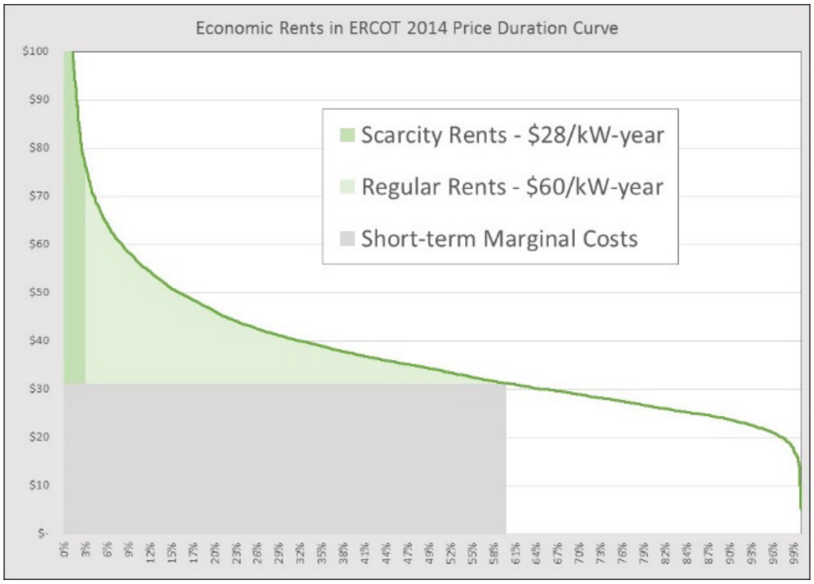


As load varies over the course of the day, different types of generators are used to produce electricity to serve that load. The baseload level of demand provides a floor on the amount of generation that is typically required around the clock on any given day. The least expensive units to operate are used to serve this base load. Then, depending on the weather, type of day (weekday vs. weekend), and economic activity, the load will increase and move around through the course of the day. As stated earlier, the level of maximum demand is called *the peak*. As load increases, generating units with increasingly higher operating cost will be used to generate more. **Figure A8** demonstrates how load increases during the course of the day, and how generating units ranked by operating cost (the bid stack) are used to serve load. Again, this graphic represents older technological choices, in which new fossil fuel is assumed to have lower operating costs than old fossil. The daily curves can be aggregated into a load duration curve. It is then possible to map the types of generating units that will serve different segments of load and create a price duration curve that tracks the amount of time that the market price is at or above a particular level **(Figure A9)**.

256 Crew, M., and Kleindorfer, P., *Public Utility Economics*, St. Martin's Press, 1979, p. 163. Reproduced with permission.

The graph can be used to understand how generators earn inframarginal rents.[257] The rectangle describes the level of operation of a generator unit at a particular price. The revenues accruing from the rectangle pay the operating costs of the generator. Above the rectangle, the generator earns inframarginal rents (when the market price is above the generator's marginal cost of operation) and scarcity rents which are earned during periods of short capacity. Returning to the hockey stick supply curve in **Figure A4,** these rents occur on the steep part of the supply curve. Therefore, for any generator, it is possible to determine how much money the generator will receive for capital cost recovery.

Figure A9: Price Duration Curve[258]



The objective of the optimal capacity mix is to determine the combination of different kinds of generation that will minimize the cost of providing power to customers over the long-run. It is a long-run economic problem focused on the choice of capital that the utility would invest in, and that would be recovered from the market. The development of the optimal capacity mix recognizes the historic tradeoff between generator capital costs and operating costs. The relative operating cost will determine how long different types of generator units will operate as reflected by the price duration curve. The result is the mix of different types of generators required to minimize the cost of providing reliable service to customers. Therefore, the problem of minimizing the total cost of generation must take into consideration the fact that different generators will have different capacity factors[259] — or levels of utilization.

Base load generation is the most capital intensive type of generators. The high capital costs are offset by the low operating costs (either because they are more efficient or because they have lower fuel costs). These generators tend

257 Inframarginal rents represent the difference between the market price and a market participants' marginal cost of production. If the marginal cost of production is less than the market price, the entity earns infra-marginal rents or revenues that are available to help amortize the capital investment.

258 Gimon, E., "On Market Designs for a Future with a High Penetration of Variable Renewable Generation," Energy Innovation, September 2017. Reproduced with permission, https://www.energyinnovation.org/wp-content/uploads/2020/01/On-Market-Designs-for-a-Future-with-a-High-Penetration-of-Renew.pdf.

259 Capacity factor is a measure of generator capacity utilization. It is the ratio of actual output to maximum possible output.

to operate continuously, providing a base upon which the rest of the dispatch stack rests. These units have characteristics that often restrict the way in which they are operated. Nuclear power plants in the United States, for example, are typically designed to operate at a continuous and full output, not to follow-load. Doing so, allows for the maximization of mechanical and thermal efficiency.

Figure A10 shows the Nine Mile Point nuclear power plant in Oswego, New York. The capital intensive nature of the plant is evident just from its sheer size. In addition to the reactor buildings, there are massive turbines generating electricity from the steam produced by the reactor, and a 541-foot cooling tower that reduces the thermal impact of circulating cooling water back into Lake Ontario.

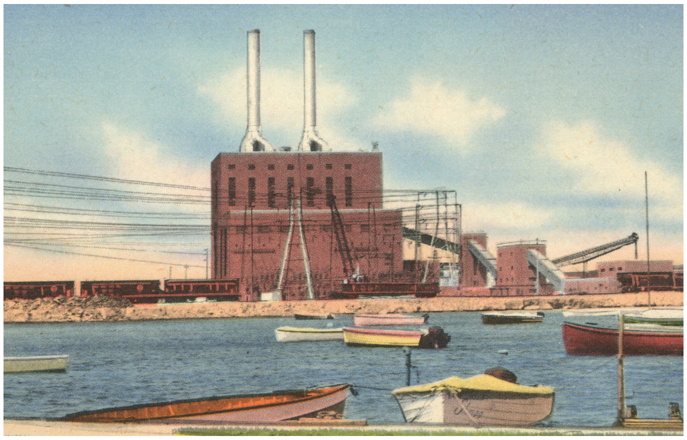
Figure A10: The Nine Mile Point Nuclear Power Plant[260]

The next class of generators is called *intermediate generators*. These may be oil- or gas-fired units that are either older, less efficient units with higher operating costs but with lower capital costs because of the choice of technology, or because capital costs have been amortized, or because they use a more expensive fuel. Historically, oil-fired units had lower capital costs than coal units, because the type of fuel handling equipment and pollution control equipment to control particulates was less intricate than for coal units. However, historically, oil prices tended to be higher than coal prices.

260 https://www.nrc.gov/docs/ML0414/ML041490223.pdf.

The Dunkirk Power Station (**Figure A11**), a coal-fired unit of 625 MW with four units is an example of the transformation of a coal-fired power plant from base load to intermediate to obsolete. The first two units began operation in 1950, followed by units 3 and 4 in 1959 and 1960. When it began operation, Dunkirk was one of the largest and most technologically advanced power plants in New York. Over time, its place in the dispatch order declined, as newer units became more efficient. Over the life of the plant, considerable expenditures were made to meet new environmental standards. Ultimately, however, with the decline of natural gas prices and a failed attempt to convert the plant to natural gas, Dunkirk was retired.[261]

Figure A11: The Dunkirk Station Power Plant



The third category of generating unit in the formulation of the optimal capacity mix are *peakers*. Peakers are the least costly type of generator to add to a system. Historically, the peaker had the lowest efficiency and tended to use the most expensive fuels (oil or gas), but its ability to come on-line rapidly made it an effective generator to meet peaks, or to provide quick-start operating reserves when required. They are essentially jet engines that turn generators. They are simple to build,[262] and some are portable. **Figure A12** is a photo of a modern peaker, in this case a mobile aero-derivative turbine. Not only can it be used to provide reliability services, but it can be transported to areas with outages resulting from catastrophic weather events.

Figure A12: Modern Peaker[263]

261 Procotr, D., "NRG Ends Effort to Repower Power Plant," *Power*, July 13, 2018, https://www.powermag.com/nrg-ends-effort-to-repower-dunkirk-plant/.

262 https://www.ithacajournal.com/story/news/local/2019/06/22/lansing-power-plant-data-center/1328220001/.

263 Courtesy of GE.

To understand FERC's pricing formula, it is again necessary to view the idea of the optimal capacity mix from the perspective of the mid-1980s and early 1990s, when there was a fairly predictable tradeoff between the cost of base load, intermediate, and peaker units. When the marginal cost of a generator is less than the market price, the generator receives revenues (infra-marginal rents) that can be used to amortize its capital investment. Base load generators and intermediate power plants earn infra-marginal rents. The degree to which they accumulate those economic rents and allow generators to amortize the capital cost of generation depends on two factors the unit's operating cost compared to the market clearing price and the amount of time (as reflected in the price duration curve in **Figure A9**) that the generators operate, accumulating those economic rents. As discussed in the next section, at the other extreme, peakers were low capital cost, generally inefficient generators that were installed for the sole purpose of maintaining system reliability. Because they do not earn infra-marginal rents, they must receive a capacity payment. Herein lies the basis for the missing money problem,

Since the concept of the optimal capacity mix was developed by Turvey in the late 1960s, there has been a great deal of technological innovation in turbine design that has dramatically increased the efficiency of peaker plants. In addition, there has been a fundamental change in the relative price of fuels, where the price of natural gas has declined dramatically, so that modern gas turbines are often less costly to operate than intermediate coal power plants.

4. The peaker as a measure of pure reliability

Customers value reliability. When customers lose electricity, they incur a cost — in the extreme, a life-threatening cost, such as the failure to support dialysis patients in the wake of Hurricane Maria in Puerto Rico. The value of reliability plays an important role in the planning and pricing of electricity. The peaker has become a focal point for proxy methods for valuing reliability and developing prices, because it provides a measure of pure reliability.

Something has to mark the value of capacity. The peaker provides a measure of pure reliability. Traditionally, the only reason to build a peaker was to create additional capacity to help maintain reliability. The heroic assumption in the Peaker Method that frames the FERC's magic pricing formula is that the target installed reserve margin is socially optimal, reflecting the societal valuation of reliability. At the optimal level of capacity, it does not pay for society to add more capacity. Below that point, the reliability benefits of adding additional capacity exceed the cost of a peaker.

On a probability basis, increases in load decrease the reliability of the system, however infinitesimally. Think of it in terms of the LOLP. Given lower levels of load, the system is better able to withstand the outage of a generating unit. The LOLP would be lower. But, what happens when there is either capacity above what is required for the installed reserve margin or too little capacity? With excess capacity, the LOLP is lower. One way to adjust the value of the peaker is to take the ratio of the LOLPs of the system at the target reserve margin and the system as found. With capacity below the reserve margin, the LOLP's are higher than optimal and the ratio will increase the marginal expected curtailment cost above the cost of a peaker. With available capacity above the reserve margin, the value will be lower.

The Public Utilities Policy Act of 1978 (PURPA), which required utilities to purchase power from owners of qualifying facilities (QF)[264] at the utility's avoided capacity cost and avoided energy cost, provided the catalyst for using the

264 Qualifying facilities are either co-generation (with a useful heat by-product) or small power production facilities eligible to receive avoided cost rates under PURPA.

Peaker Method in market design. PURPA required the states to administratively determine the price for QFs. To do this, the New York Public Service Commission adopted what they dubbed the Peaker Method.[265] The Peaker Method uses the cost of a peaker to estimate the value of generation capacity. That capacity payment is critical both as a source of revenues and to provide price signals for the entry and exit of resources (e.g., retirement of generation).

The peaker as a measure of pure reliability provides the basis for estimating the capacity component of the Peaker Method. There is no single name for this term. It is described as the generation capacity payment, the Installed Capacity Payment (ICAP) and the Value of Lost Load (VoLL). What is important is that this concept plays a significant role in determining the profitability of generation investment (i.e., determining whether or not there is missing money) and also serves as a market price signal for the need for additional generation and the retirement of existing generation.

265 The New York Commission also refers to this as the Promod/Peaker Method. Promod is a production costing model that simulates the operation of power systems, such as the New York Power Pool, and its use allowed the estimation of marginal energy costs.