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by

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Thank you, Chairman Murkowski and Ranking Member Manchin, for the opportunity to testify today. In this 116th Session of the United States Congress, the electricity market will be wrapping up a decade that has seen tremendous change. Natural gas has boomed as a source of energy, coal has declined, and both because of policy interventions and their falling costs, over the next two decades, renewable sources of energy are poised to make up a significant, and perhaps even a majority, share of energy.

Few of these outcomes were predicted at the outset of this century or even at the beginning of the last decade. That fact—the unpredictability of the energy economy—suggests that it is important to have an electricity market that does not pre-ordain outcomes through mandates and subsidies. Instead, it is important to consumers that the market prices electricity at its value, in real time and on that basis, sends meaningful price signals to those who would develop, invest in or contract for new and existing technologies.

There are many opportunities for important reforms in the electricity markets. Most of these fall squarely in the lap of the wholesale electricity markets' federal regulator, the Federal Energy Regulatory Commission (FERC). Still, others are the business of state legislatures and public utility commissions. However, there are places where congressional intervention, whether through legislation or oversight, would be useful.

Accordingly, my testimony highlights a few of the issues associated with the evolving market for electricity and begins with a law that has not aged especially well in light of all the changes we have seen in the electricity market, the Public Utility Regulatory Policies Act of 1978, or PURPA.

PURPA Reform

The most important section of PURPA requires utilities to buy the energy and capacity of certain Qualifying Facilities (QFs) at a non-discriminatory rate.[1] FERC interpreted this to mean that the price paid to QFs should equal the avoided cost or the price that a utility would otherwise pay to acquire the same quantity of energy and capacity.[2] However, this fair-sounding principle fails to work in practice.

For nearly a decade, I served as a utility regulator at the Montana Public Service Commission. In determining PURPA rates, I took estimates and projections of nearly a dozen different variables—for example, the price of natural gas, the capital cost of new power plants or the future tax that might be associated with a ton of carbon dioxide emissions—and ran those estimates through a formula, which in turn spit out a number. My colleagues and I then issued a regulatory order, which, with little confidence, was our best estimate of the cost of energy over the next two decades. It is almost needless to say that my projections were almost-always wrong. Sometimes they were too low, in which case few, if any, QFs would contract with the utility. And sometimes the prices I ordained were too high, in which case a bonanza of QFs flooded the utility's doors to take advantage of this generous rate. This is where PURPA's internal logic crumbles. PURPA developers typically sign contracts when the avoided cost is too high, not when it is too low. Now that FERC and the states collectively have four decades of experience under PURPA, it is clear why PURPA projects tend to be some of the highest-cost projects in any given jurisdiction.

The fundamental problem of PURPA is *not* the requirement that utilities purchase energy from independent developers, provided it is as or more affordable than if the utility built a project itself. Instead, the problem is the fact that the administrative price forecasting on which PURPA's implementation relies is a suboptimal way to engage in what economists call "price discovery." A competitive solicitation allows rival parties to bid against one another in the hope of obtaining the business of consumers. PURPA, meanwhile, turns "price discovery" into an act of litigation, with a QF and a utility each trying to convince a government regulator what the right "price" is.

Ironically, PURPA today may actually be a barrier to state attempts to contract with lower-cost renewables. In August 2017, Public Service Co. of Colorado, an Xcel operating company, issued

[1] Public Utility Regulatory Policies Act of 1978, 92 Stat. 3157, (codified at 16 USC § 824a-3).
[2] 18 CFR § 292.304.

a competitive solicitation. It received a large number of extraordinarily low-cost bids for renewable energy. The Colorado Public Utilities Commission reviewed the bids and approved the utility's proposal to select a number of independent projects that had submitted low bids. However, relying on PURPA, a bidder who was not awarded a contract asserted a right to sell the output of 17 projects totaling about 1,400 megawatts of generation to the utility, and claimed that it should be awarded an "avoided-cost" rate based on an administrative calculation using 2016 data. That rate would be significantly higher than prices that emerged from the solicitation. And because the utility does not actually require that amount of energy to serve its customers, accepting the jilted bidder's PURPA claims would mean either canceling projects that *were* low-cost bidders or buying more energy than customers actually need.

Citing this example and others, the National Association of Regulatory Utility Commissioners (NARUC) has issued a proposal, which calls upon FERC to waive PURPA's mandatory purchase obligations for those states that have competitive frameworks for the procurement of energy and capacity.[3] This would allow FERC to establish regulations that ensure that the state frameworks are genuinely competitive and open to QF technologies. And it would allow states to avoid the sure-to-be-wrong rigmarole of decreeing prices through regulatory forecasts. FERC already has granted a limited exemption to utilities in the footprints of Regional Transmission Organizations (RTOs). Yet, even in those states outside of RTOs, such as in the Western United States, the use of competitive solicitations is widespread. In the Energy Policy Act of 2005, Congress has also clearly signaled to FERC that the agency should be flexible as market models for electricity develop. In NARUC's proposal, FERC has an opportunity to reform PURPA in a way that is even-handed to all. The agency should take that opportunity.

State Subsidies and Competitive Markets for Electricity

As the market for electricity has changed, it has created winners—and losers. In many parts of the country, the cost of new entry for certain power plants is less than the going-forward cost of operating certain existing generators. In such conditions, an efficient market will cause existing resources to retire in the face of lower-cost new entrants. This trend is natural and economically rational—indeed, it is a sign of innovation within an industry.

This trend is not solely due to economics, however. It has been accelerated by state and federal policies. State mandates and federal tax subsidies allow resources that would not otherwise be economical to enter the market.[4] At the same time, several states have recently adopted

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[3] Travis Kavulla and Jennifer Murphy, "Aligning PURPA with the Modern Energy Landscape: A Proposal to FERC," National Association of Regulatory Utility Commissioners, October 2018. https://pubs.naruc.org/pub.cfm?id=E265148B-C5CF-206F-514B-1575A998A847.

[4] However, for the first time this year, Lazard projects that the average *unsubsidized* levelized cost of energy produced by new wind is less than the average LCOE of existing coal. "Levelized Cost of Energy Analysis," Version 12.0, Lazard, 2019. https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-

policies to subsidize the continued operation of certain existing resources, which otherwise would have retired in the face of competition by both subsidized and unsubsidized new entrants.[5] Still other jurisdictions, where power generation is owned by regulated utilities, effectively have shielded power plants from the economic pressures of competition, more subtly directing subsidies to out-of-market resources in the form of ratepayer guarantees.[6]

In short, policymakers are subsidizing certain resources to enter the market and policymakers are also subsidizing other resources to prevent them from leaving. Moreover, while these policy interventions were at one point relatively limited in nature, they have grown in number and in scale over the last few years. These developments have borne out a prediction made by the independent market monitor of one of the nation's largest electricity markets, PJM, when he observed that: "Subsidies are contagious. Competition in the markets could be replaced by competition to receive subsidies."[7] According to a 2018 report by the market monitor, in the PJM market alone, these subsidies were estimated to total $3.8 billion, although the number would certainly be higher today.[8] This is a significant number when compared to the total revenue resulting from the PJM capacity auction—$10.3 billion for 2018.

The inevitable result of these subsidy policies is that consumers, in one form or another, are paying for power plants that they do not need. For this 2018/19 winter season, NERC projects that each region of the country had significantly more resources available than were needed when compared to total consumer demand and while including a margin for reserves.[9] When one turns to the summer analysis that NERC conducts, the story is much the same, although the

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2018. It should be noted that the LCOE analysis employed by Lazard has its critics and other authors suggest that the LCOE of new renewables remains higher than the marginal cost of existing plants. See, for example, Gurcan Gulen, "Electricity Markets, the Grid, and the Net Social Cost of Energy," *forthcoming*.

[5] New York, Illinois, New Jersey and Connecticut.

[6] About one-third of the United States population is served by vertically integrated utilities, the power-generation-related revenue of which is a function of the generation's cost to operate, rather than its value in the wider wholesale market.

[7] "Statement of Joe Bowring, Independent Market Monitor for PJM," FERC Technical Conference on State Policies and Wholesale Markets, May 1-2, 2017, p. 3. https://www.ferc.gov/CalendarFiles/20170426150935-Bowring,%20Monitoring%20Analytics.pdf.

[8] "The Value of Markets," PJM, June 2018, p. 5. https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/the-value-of-pjm-markets.ashx.

[9] "2018/2019 Winter Reliability Assessment," North American Electric Reliability Corporation, p. 7. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_WRA_2018_2019_Draft.pdf.

Texas electric market, which has a market design that aggressively promotes economic efficiency, naturally has a much tighter operating margin.[10]

FERC's Regulation of Capacity Markets

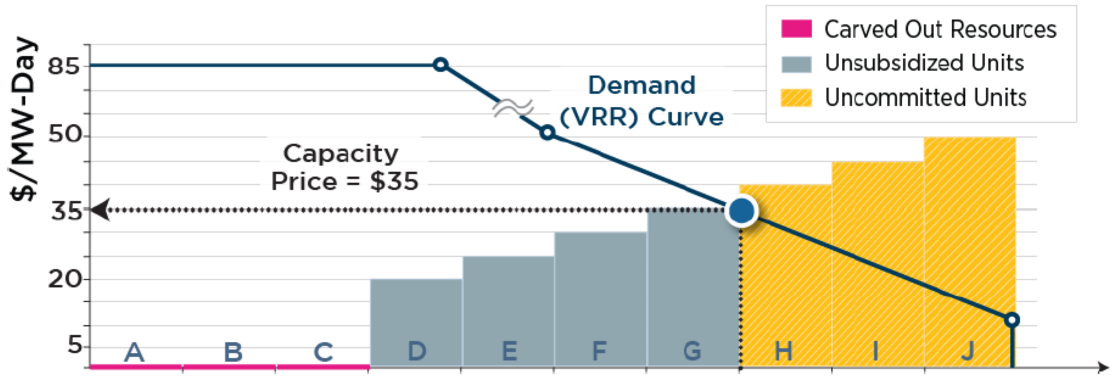
If it were not for subsidies favoring certain power plants, other unsubsidized resources would be economical. In an effort to deal fairness to those unsubsidized market participants, the Regional Transmission Organizations (RTOs) and the Federal Energy Regulatory Commission (FERC) have frequently re-designed parts of the electric wholesale markets to deliver them additional revenue. A special focus of these initiatives has been the centralized capacity markets the eastern RTOs[11] administer, where reforms have sought to mitigate the effect of subsidies and preserve a "competitive" price signal to generators who do not benefit from subsidies.

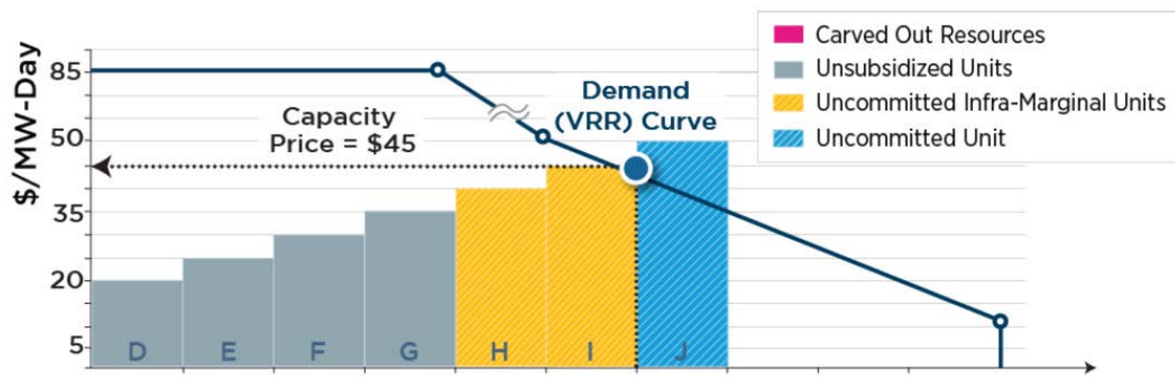
Though well intentioned, these efforts are a road to nowhere. An instructive example in this regard is PJM's proposal for "carve out and repricing." Under this market design, PJM would "carve out" subsidized resources from participation in its capacity auction and "reprice" the auction's outcome as if those power plants did not exist. However, when actual supply is artificially removed but demand is held steady, prices of course rise. Illustratively, PJM's proposal to carve out subsidized resources is shown below:[12]

[10] "2018 Summer Reliability Assessment," North American Electric Reliability Corporation, 2018. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_05252018_Final.pdf. The Public Utility Commission of Texas recently modified the method by which operating reserves are procured by the market, making the procurement more robust in times when customer demand and weather-dependent intermittent resources are volatile

[11] By "eastern RTOs," I include PJM, ISO-New England and the New York ISO. Each of these operate markets where incumbent utilities do not own the bulk of power generation on a traditional "cost-of-service" basis, and where power generators instead expect those revenues derived from RTOs' energy and capacity auctions either to make up the bulk of their revenues, or to form the basis on which forward contracts and hedges are priced. Other RTOs, including the Midcontinent ISO, the Southwest Power Pool and the California ISO largely exist to optimize the dispatch of resource entry and exit decisions that occur at a more granular state- or utility-level.

[12] Images taken from "Initial Submission of PJM Interconnection," FERC Dkt EL18-178-000, Oct. 2,2018, pp. 66-67.





For whatever virtue there may be in attempting to preserve a so-called "competitive" price signal, the PJM proposal invents a kind of parallel universe in order to get the "right" (i.e., higher) prices. PJM had asked FERC to rule on this proposal last month but the matter remains pending as of the submission of this testimony. I am sympathetic to those enterprises that have not received subsidies but face competition by subsidized resources. However, I am concerned that the remedy PJM has proposed is a reform that makes its market more and more an arbitrary, administrative construct and less and less a market whose prices are the function of the real balance of supply against demand.

The simple reality is that the only way to eliminate subsidies is to eliminate the subsidies. Yet this kind of preemption of state policies is not something that FERC has suggested. Indeed, it has argued against it—making the regulator one of the few federal agencies to adopt a self-denying, modest view of its powers.[13]

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[13] *Brief of the United States and the Federal Energy Regulatory Commission as Amici Curiae in Support of Defendants-Respondents and Affirmance*, Case No. 17-2433 (7th Circuit, 2018). Available at: https://www.ferc.gov/legal/court-cases/briefs/2018/7th17-2433etalVillageofOldMillCreekAmicusBrief.pdf.

Congress's Role relative to State Subsidies

So what is to be done? In recent years, the most dynamic movers of subsidies and out-of-market payments are state legislatures and public utility commissions. Congress could pass a law expressly countermanding state policies. However, this would represent a marked shift in the division of federal and state jurisdiction over electricity generation. Although the effects of power generation in large regional grids are interstate in nature, the Federal Power Act and subsequent energy laws largely reserve the authority over electricity generation to the province of state policymaking. Congress's decision to leave this networked industry in the hands of local regulators causes this networked industry not to resemble others, like telecommunications or railroads, which were, at first, gradually and then in the 1980s and 1990s, quite rapidly federalized in order to promote consistent standards and economic efficiency.

If Congress does not act, then a two-staged future could occur. In the short term, I would expect more state legislatures to adopt policies that subsidize politically favored sources of electricity. However, in the medium-to-longer term, subsidies for electricity will cause regulated rates in those subsidy-prone states to rise, even while the overall effect of the subsidies—keeping more supply than is necessary to meet regional consumer demand—will suppress prices available on the wholesale market. PJM's wholesale prices have declined 40 percent in the past decade, even while regulated retail prices have *increased*.[14]

The consumers of subsidy-prone states will thus pay higher rates and the ultimate winners—the beneficiaries of a surplus that other states' consumers have paid for—will be the consumers of states that have been less profligate. In this way, the electricity markets have a similar dynamic to dumping in the context of foreign trade: Dumping has negative effects on local manufacturers but is fundamentally a wealth transfer from the producing nation to the consumers of the nation who buy the product. In the same way, a state that has not (yet) doled out subsidies to power generation, like Ohio, may be crowded out of opportunities to develop power plants that would be economical in a marketplace free of subsidies. Yet, Ohio's electricity consumers, large and small, ultimately would benefit from others states' decisions to subsidize their production.

Should they grow too ostentatious, subsidy policies may generate a political feedback loop in the subsidizing states, where politics can be expected to tolerate such a giveaway for only so long. In places with rising regulated rates and falling wholesale costs, one can already see the dissatisfaction on the part of consumers who would rather pay the latter. This is what has given rise to Community Choice Aggregators in California, to the movement by casinos and data centers in Nevada to directly access the wholesale market and to demands by industrial customers in Michigan to cap "direct access," which limits participation. Ultimately, it will be the dissatisfaction of the most essential component of the energy system—the consumer—that

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[14] "The Value of Markets," p. 2. https://www.pjm.com/-/media/about-pjm/newsroom/fact-sheets/the-value-of-pjm-markets.ashx.

will impose discipline on policymakers whose decisions raise costs too radically. Empowering those consumers will help accelerate that discipline.

Congress has previously invited states to consider energy policies—instead of mandating them—on a host of topics, from PURPA's direction to consider time-of-use rates[15] to the Energy Policy Act of 1992's definition and direction to consider integrated resource planning[16] to the Energy Policy Act of 2005's direction on net-metering.[17] Rather than intervene with a heavy hand, what Congress can and should do, in any general energy legislation, is to encourage states to consider increasing customer choice. Additionally, through the Department of Energy, it should consider making funds available to states who elect this policy in order to set up an online marketplace for customers to shop for an energy provider of their choice.[18] Finally, Congress should consider requiring states to disclose the cost of carbon reductions associated with particular subsidies and to consider providing for a disclosure on consumers' bills.[19] This would help promote customer and policymaker consideration about potentially cheaper ways to obtain the same reductions.

Electricity policy remains entirely too paternalistic and there is today no sound policy reason why sophisticated consumers of electricity should have to buy a product ordained for them by a regulator. If more states allowed direct access to the wholesale market by even their largest consumers of energy, policymakers would also be able to put to the test the proposition underlying many subsidy policies: that consumers are demanding clean energy. In my view, they are—and they will be willing to contract for it separately, in quantities that they choose and at competitive prices.

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[15] Public Utility Regulatory Policies Act of 1978, 92 Stat. 3117 (codified at 16 USC § 2621)

[16] Energy Policy Act of 1992, 106 Stat. 2776 (codified at 16 USC §§ 2602, 2621).

[17] Energy Policy Act of 2005, 119 Stat. 594, 962 (codified at 16 USC § 2621).

[18] While large customers are sophisticated enough to shop for electricity providers on their own, websites established in certain states with customer-choice policies that allow residential customers to shop around are transparent, easy-to-use tools that allow customers to choose between different rate plans, contract lengths and products (e.g., all-renewable) See, for example, http://www.powertochoose.org.

[19] The PJM market monitor independently calculated that the implied cost of carbon reductions associated with the solar renewable energy credit obligation of the District of Columbia is $861.52 per tonne—a cost which is orders of magnitude above the cost of carbon reductions obtained by more efficient policies in the region. This fee is charged to district residents through a non-bypassable fee on the distribution side of the customer bill, which means that even the District's policy of customer choice does not allow customers to avoid it. However, if more transparently priced on the customer bill, it might create momentum to seek alternative, more cost-effective policies. See: "Quarterly State of the Market Report for PJM: January through June," Monitoring Analytics, LLC, August 2018, p. 329.

Pricing Electricity at its True Value in Wholesale Markets

The RTOs and FERC have consumed a significant amount of time and resources attempting to fix the eastern RTOs' capacity markets. At the same time, other problems of market design deserve their urgent attention.

Many states have passed or will pass mandates that require their utilities to procure a certain percentage of clean energy resources by a certain year. The most ambitious states have pushed 100 percent clean energy targets in just two or three decades. Much of this clean energy will be weather-dependent renewable resources, especially wind and solar power. Since the fuel for these resources is free, they are sometimes referred to as "zero-marginal-cost" resources. While they have substantial capital costs in the first place, once built and if properly maintained, they produce energy essentially without cost in any given hour when their fuel (the sun or the wind) is available. (In fact, because of federal production tax credits, which yield a tax benefit equivalent of $24 per megawatt-hour but *only* when the wind produces, this form of subsidy actually causes certain wind generators to be willing to *pay* customers to take their energy output.[20]) Axiomatically, in the auctions of RTOs, the wholesale price of energy is a function of the most expensive unit of supply necessary to meet consumer demand. However, when a system is so dominated by renewables that its output is sufficient to meet customers' needs, the wholesale price of energy may be zero or even become negative.

Yet, there will also be periods when the sun is not shining and the wind is not blowing. Some of these periods are highly predictable—the evening for solar. Some are somewhat predictable—for example, the relative intensity of the wind by season, e.g., in a place where Santa Ana winds tend to blow. And some of these periods are hardly predictable at all—as in the case of a passing cloud or the vacillations in wind speed on a gusty day.

The longer periods of intermittency introduced by renewables, as well as the more unpredictable episodes of volatility, have profound implications for the grid. The energy markets' prices should appropriately reflect these more volatile system conditions and periods of scarcity. Such prices provide an economic signal for the construction and operation of the most cost-effective and reliable set of resources that can make up the gap when other resources are temporarily , or for hours, or for days, unavailable. In the future, what we had come to think of as "capacity" resources will instead need to fill this breach flexibly but durably and be compensated by or on the basis of the energy-market prices during times of system

[20] The production tax credit (PTC) is being phased out but many wind projects have been safe-harbored by IRS guidance associated with the beginning of these construction projects. For projects that began construction during or before 2016, the full value of the PTC for ten years is given. The PTC steps down by 20 percent each year thereafter and, unless Congress renews the program, is unavailable for projects that commence in 2020 or after. See: "Renewable Energy Tax Credit," U.S. Dept. of Energy, accessed Jan. 31, 2019. https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc.

scarcity or stress.[21] At the moment and for a variety of technical reasons, the prices in RTOs during times of system stress or scarcity do not reflect these tight system conditions. Instead, during these periods, market operators all too often take administrative actions that have the effect of suppressing the market price, while socializing the cost of system scarcity or stress.

FERC should begin to address these more essential questions of electricity market regulation in the 21st century. A good starting point is for FERC to give priority consideration to the proposals that will emerge from PJM's work on energy price formation and reserve products.[22] As a second-order issue and after it concludes its work on energy pricing reforms, FERC should then consider whether additional safeguards associated with add-on reliability products or standards are needed. Politics has forced this issue into a defining role of electricity-market discussions but it is, in fact, a sideshow to the basics of electricity market reform, which should convey appropriate economic incentives to generators to assure reliability. An appropriate end result to such work would be an electricity market that fully supplants today's mandatory capacity markets.

Ensuring Energy Transport Networks are Robust

Finally, it is necessary to ensure that the underlying networks on which the market in electricity relies—the electric and natural gas transmission systems—remain robust and reliable.

Siting both natural gas pipelines and electric transmission lines has become more challenging over the past ten years. Environmentalists have routinely objected to natural gas pipelines, although it is natural gas more than any other source of electric power that has achieved the greatest carbon-emissions reductions in the electricity sector.[23] Electric transmission, meanwhile, is cost-effective only when sited above ground, except in very limited circumstances; landowners and neighbors object to it on aesthetic and land-use grounds. For different reasons, probably more of each of this infrastructure is necessary, at least in certain places. More electric transmission will be necessary in order to ensure renewable energy resources can reach population centers, and in doing so a grid should be knit together that has more diversity of resources—and thus less of the volatility described above. Natural gas transmission, meanwhile, is a cornerstone of reliable grid operations. Although some have suggested that such assets will not be needed in a system largely dominated by renewables, this is inapposite: Gas transmission provides a form of energy storage that can be called upon

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[21] A short explanation of the principles behind this are laid out in William Hogan, "In My View: Best Electricity Market Design Practices," 2018. https://sites.hks.harvard.edu/fs/whogan/7_Best_Practices%20(Hogan)_RCH_03_10_18MIH_rev_final_072518.pdf.

[22] "Board Directs PJM, Stakeholders on Reserve Pricing," PJM, Dec. 6, 2018. http://insidelines.pjm.com/board-directs-pjm-stakeholders-on-reserve-pricing.

[23] "Global Energy & CO2 Status Report," International Energy Agency, accessed Jan. 31, 2019. https://www.iea.org/geco/emissions.

during periods of renewable intermittency and volatility. Even if less natural gas is ultimately used in power plants to generate electricity, having more gas transmission capacity—as well as back-up fuel sources for those power plants—is a reliable feature that becomes more important in a system with, for example, less coal and more renewables.

These issues of infrastructure siting have taken on a dimension wherein certain states obstruct the energy policies of other states that are geographically unlucky. New England's RTO, the ISO-New England, has repeatedly warned that without additional natural gas capacity, its system faces reliability risks.[24] In 2015, New England's governors unanimously adopted a policy statement calling for additional gas infrastructure.[25] Meanwhile, New York has imposed a *de facto* moratorium on natural gas pipelines—using state authority over water permits to frustrate a largely FERC-jurisdictional process under the Natural Gas Act. This means that New England states cannot access one of the most productive gas fields in North America, located across New York in Pennsylvania and Ohio.

Similar issues arise in electricity transmission. Several interstate transmission lines have been proposed to facilitate the development of renewable energy, and approvals have been obtained in one state, only to be blocked in others.[26] This has prevented interior states with rich renewable resources from developing their energy economy and it has also prevented states interested in purchasing renewables from accessing their intended supply.

Although not related to domestic electricity production, a similar story has unfolded with the State of Washington and Cowlitz County's environmental review of the Millennium Bulk Terminals' proposal for a coal export facility at Longview, Washington. Wyoming and Montana have both extensively promoted the coal mined in the Powder River Basin for Asian export but those development prospects have effectively been blocked by a single state.[27]

Congress should therefore consider whether individual states should be permitted to frustrate the energy policies of other states so wantonly. Some scholars have suggested empowering the

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[24] "Natural Gas Infrastructure Constraints," ISO-New England, accessed Jan. 31, 2019. https://www.iso-ne.com/about/regional-electricity-outlook/grid-in-transition-opportunities-and-challenges/natural-gas-infrastructure-constraints.

[25] "Governors' Statement on Regional Cooperation on Energy Infrastructure," New England States Committee on Electricity, April 23, 2015. http://nescoe.com/resource-center/govs-stmt-apr2015.

[26] Examples include Northern Pass to bring Quebec hydropower to Massachusetts and the Grain Belt Express to bring wind from Kansas to the MISO market.

[27] Tom Lutey, "Montana, Wyoming join battle over Washington coal port," *Billings Gazette* May 11, 2018. https://billingsgazette.com/news/state-and-regional/montana/montana-wyoming-join-battle-over-washington-coal-port/article_a09eaa35-4538-5b1c-8174-510e70de95e0.html.

FERC "to approve all modes of interstate energy transport."[28] I would not go that far. However, it is necessary to have a backstop federal permitting regime, which could act as a "tie breaker" when one state has sited or declared through policy the need for energy infrastructure and another has declined to permit or rejected a permit for the same. Additional protections could be written into such a statute, including a requirement that linear infrastructure have a certain amount of its mileage signed up through voluntary landowner agreements before it may resort to eminent domain. Or, for those projects where the off-taker entity is an affiliate of the developer of the transmission line or pipeline, a stricter standard for project necessity might apply. But, for projects that have an arm's-length and voluntary relationship between the infrastructure owner and the entity or entities paying for it, the federal statute could allow permitting to be accomplished more easily, on the basis that stronger evidence exists as to need.

Once again, it has been my pleasure to testify before you today. I appreciate the Committee's consideration of my views, and I wish you luck and wisdom as you approach your work in this session of Congress.

[28] James W. Coleman, "Pipelines and Power-lines: Building the Energy Transport Future," *Ohio State Law Journal* 79 (*forthcoming 2019*), p. 43. https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3172652