Comments of the Clean Energy Advocates on NYISO's Proposed Application of Buyer-Side Mitigation Rules to DERs

June 15, 2018

Natural Resources Defense Council, Alliance for Clean Energy New York, and Acadia Center (collectively "Clean Energy Advocates") are very concerned by the suggestion in NYISO's DER Market Design Updates presented to stakeholders during the June 1 Market Issues Working Group meeting that NYISO may apply buyer-side mitigation (BSM) screening procedures to DERs in the capacity market. We urge NYISO to adopt a blanket exemption from BSM rules for DERs. A blanket exemption would produce just and reasonable rates, whereas the plan suggested by NYISO at the June 1 meeting would not be just and reasonable, for the reasons set forth below.

No evidence has been put forth demonstrating that DERs have the incentive or ability to artificially suppress capacity prices, and FERC's recent decisions on NYISO's buyer-side mitigation rules demonstrate that DERs supported by state programs do not warrant mitigation. While the majority of DERs are likely to pass NYISO's Part B test, any failure by resources to pass that test would stem from deficiencies in the Part B test, which uses a 3-year time horizon inappropriate to most DER technologies. Thus, beyond making the process for DER market participation far more burdensome, NYISO's proposal to apply buyer-side mitigation rules to DERs would likely over-mitigate these resources, resulting in higher costs for NYISO customers while providing virtually no benefit.

Applying BSM screening to DERs would also mire DERs seeking to participate in NYISO's capacity market in a burdensome process so costly and time consuming as to dissuade market entry by these resources. This would frustrate NYISO's goal of facilitating market participation by DERs and would clash with FERC orders, such as FERC's recent order to RTOs to eliminate barriers for energy storage participation.[1] Delay and higher costs caused by applying BSM to DERs also would have negative ramifications for NYISO's market beyond its effect on DERs. It could delay the interconnection process for all resources, including non-DER resources. Further, it may set a precedent that could compromise the ability of NYISO's capacity market to incent the appropriate amount of resources when accounting for legitimate state policies.

A. Because DER resources do not present a risk of artificial price suppression warranting mitigation, NYISO should exempt DER from buyer-side mitigation screening.

NYISO should exempt DER resources from its BSM rules. Multiple factors dictate that DER resources participating in NYISO's programs do not present a risk of artificial price suppression. As FERC explained in its most recent order addressing NYISO BSM rules, "buyer-side market power mitigation rules are intended to address 'market power exhibited by certain entities seeking to lower capacity market prices.'"[2] Like Special Case Resources (SCR) that are exempt from BSM, DERs more generally do not "have the same ability to influence market prices" as "a single, large market participant," because on an individual basis and even when aggregated, they are very small in relation to other capacity market resources. DERs (individually or in aggregations) cannot appreciably swing market prices, and thus will not be used for market

[1] Docket Nos. EL16-33 and AD16-20, Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 162 FERC ¶ 61,127 (Feb. 15, 2018) ("Order No. 841"). The order states, for example, that "effective integration of electric storage resources into the RTO/ISO markets would enhance competition and, in turn, help to ensure that these markets produce just and reasonable rates." *Id.* at P 12.

[2] Docket No. EL16-92, *New York Public Service Commission v. New York Independent System Operator, Inc.*, Order Granting Complaint in Part and Denying in Part, 158 FERC ¶ 61,137 at P 30 (Feb. 3, 2017).

manipulation.[3] Recognizing the similarity between SCRs and the broader range of DERs, NYISO has proposed in its DER Roadmap to "aggregate DER[s] similar to its existing demand response programs [SCRs], with certain modifications to reduce the minimum aggregation size . . . ."[4]

Further, as for SCRs that FERC ordered NYISO to exempt, the additional revenue streams that DERs may leverage beyond the NYISO markets compensate DERs for non-FERC jurisdictional services. Consistent with NYISO's BSM practice, that renders reduced offer prices that those revenue streams may enable appropriate, not "artificial."[5]

State-jurisdictional programs may compensate DERs for beneficial externalities that they create, or harmful externalities that they avoid, such as reduced harmful emissions or increased innovation. NYISO's Part B test includes such revenues in its 3-year revenue projection because, as with revenues from sales of other non-jurisdictional products, revenues from sales of environmental credits or compensation for innovation benefits are rationally and economically included within a resource's offer prices.[6]As the Institute for Policy Integrity recently pointed out, allowing offer prices to include such "externality payments" produces outcomes that are more

[3] Further, under NYISO's participation model, an aggregator rather than an individual DER resource controls NYISO market offers. Applying BSM to an individual DER resource makes little sense in this context, because the individual resource could not act to manipulate market prices even if it wanted to. In many cases, DER within an aggregation may be owned by several different entities, separating the aggregator's offer incentives from those of the owner of any single DER within the aggregation.

[4] New York Independent System Operator (NYISO), Distributed Energy Resources Roadmap for New York's Wholesale Electricity Markets 17 (Jan. 2017) ("DER Roadmap").

[5] For a more detailed description of why this is the case, *see* Docket No. ER18-1314, Protest of Clean Energy Advocates, at 106-115 (May 7, 2018).

[6] *See New York Public Service Commission v. New York Independent System Operator, Inc.*, 153 FERC 61,022 at P 48 (Oct. 9, 2015) (for renewable resources that are not otherwise exempt from buyer-side mitigation rules, Part B of the mitigation exemption test "takes into account certain incentives for owning renewable resources by reducing the unit-specific Net CONE").

economically efficient than excluding them.[7] Treating these revenues as legitimate is consistent with NYISO's treatment of state actions that increase offer prices, such as its participation in the Regional Greenhouse Gas Initiative or the emissions regulations promulgated by the Department of Environmental Conservation. NYISO allows market actors to reflect these costs in offer prices and does not take action to reduce capacity market prices in response to this price inflation. As the Market Monitor's recent presentation highlighting is 2017 State of the Market Report suggests, the net impact of all state programs will likely *increase* capacity market prices,[8] yet NYISO does not apply any downward adjustments to account for state policies, implicitly recognizing that these policies are valid and have real economic consequences.

Other state programs compensate DERs for retail-level services that are "separate and distinct" from wholesale services that those same resources may provide. For example, systems participating in utility non-wires alternative programs are compensated for their benefits to the distribution system rather than for wholesale system value streams. NYISO should facilitate dual participation by DER in retail and wholesale markets so as to fully leverage the value of DER.[9] Consistent with FERC's order requiring NYISO to exempt SCRs from BSM, compensation for

[7] Sylwia Bialek, Ph.D. & Burcin Unel, Ph.D., Institute for Policy Integrity, Capacity Markets and Externalities 10 (Apr. 2018) ("IPI report").

[8] *See* Potomac Economics, Highlights of the 2017 State of the Market Report for the NYISO Markets, ICAP Working Group (May 23, 2018).

[9] State agencies are explicitly structuring programs to allow for this. For example, NYSERDA's Demonstrating Distributed Energy Storage for 'Stacking' Customer and Grid Values and Program Opportunity Notice (PON) 3541 seeks "commercial distributed energy storage systems that leverage the flexibility of energy storage to 'stack' two or more value systems by performing multiple functions for retail electric customers, distributed generation, utilities and the NYISO." The program provides compensation in based on retail-level services. The PON is accepting applications through December 2019. *See* New York State Energy Research and Development Authority, Demonstrating Distributed Energy Storage for 'Stacking' Customer and Grid Values Program Opportunity Notice (PON) 3541, available at https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pt0000004FOnAEAW.

distribution system services does not artificially suppress prices. Rather, like compensation for environmental benefits, such revenues are rationally and economically included within offer prices. Indeed, mitigating resources based on their receipt of revenue compensating distribution system services would entail arbitrarily ignoring these valid state property rights while respecting others.

Further, no evidence has been presented that DERs that would participate in the NYISO market receive compensation pursuant to state programs that mirror the Maryland program overruled in *Hughes v. Talen Energy Mktg., LLC*.[10] Buyer-side mitigation was applied to that program by PJM, but it was fundamentally different from New York's DER initiatives because it adjusted a generator's compensation for wholesale capacity sales in contravention of the rates FERC had already approved, and therefore did not create a valid state property right. Here, no one has suggested that the state programs at issue do not create valid state property rights.

In determining whether to apply BSM rules to DERs, NYISO should not require a demonstration that no DER could *ever* artificially suppress prices. Doing so would require supporters of DER market participation to meet the impossible task of proving a negative. While FERC looked to specific evidence in granting an exemption for SCRs, that was in the context of a section 206 complaint, where the burden fell on the complainants to demonstrate that the existing tariff was not just and reasonable. By contrast, in the context of a section 205 filing, NYISO should look to a representative sample of state policies, from which it can conclude that an exemption is just and reasonable because DERs are not making offers based on illegitimate revenues that would "artificially" suppress prices. This, combined with the small size and inability of DER owners to use DER to manipulate prices renders an exemption appropriate. Concluding that an exemption is

[10] 136 S. Ct. 1288, 1289 (2016).

just and reasonable is further supported by the fact that, as explained below, applying BSM to DERs would greatly complicate NYISO's interconnection process, creating inefficiency and delay not only for DERs but also potentially for an even wider range of resources. Granting an exemption would not preclude a market participant from subsequently making a case with regard to a specific resource that it has the incentive and ability to artificially suppress prices, and should therefore be mitigated. But that hypothetical future scenario, which could easily be addressed by a section 206 complaint, does not justify the adoption of burdensome and inefficient rules with regard to all DERs.

B. Applying BSM rules to DERs would be extremely administratively burdensome, increasing costs and delays not only for DER but potentially even for a broader set of resources.

Applying BSM to DERs would be extremely administratively burdensome. NYISO's June 1 MIWG presentation explains that NYISO plans to assign Capacity Resource Interconnection Service (CRIS) to individual resources through its interconnection process. While the exact process for assigning CRIS has not been established, conceivably NYISO could do this in a manner akin to its rolling enrollment process for demand response resources. In order to facilitate wholesale market participation by DERs, it is essential that NYISO establish an efficient interconnection process that matches participating resources' small size. A smaller resource's proportionately lower revenues simply will not justify administrative costs comparable to those of larger resources.

It is difficult to see how NYISO could possibly apply BSM to DERs in a manner that facilitates a streamlined and efficient interconnection process. Part B analysis for individual DERs would require a particularized study for each individual resource, meaning that separate analysis may need to be carried out for hundreds of different resources. Assuming BSM determinations would be conducted in tandem with NYISO's interconnection process (as NYISO's tariff appears to require), that would not only subject DER owners to lengthy delays and unnecessary costs, it could delay the entire interconnection process for other class year participants.

Faced with the costs and delay such a process would entail, many potential DER market participants would decline to pursue NYISO market participation, frustrating FERC Order No. 841's goal of facilitating wholesale market access for energy storage resources, including distributed energy storage resources. Market participation by DERs is in customers' interests because it promotes greater competition in NYISO's markets and lower rates. It is also in NYISO's interests because DER participation promotes NYISO's ability to provide for a reliable bulk power system. NYISO has visibility and operational control over resources that participate in its markets. NYISO has recognized that that the aggregation of "individual DER[s] to meet wholesale market eligibility and performance requirements is beneficial to both market participants and the markets."[11] NYISO should therefore strive to establish market rules that facilitate dual participation by DERs in wholesale and retail markets, and avoiding cumbersome BSM processes is one necessary component of achieving that goal.

Analysis under the Part B test would be unnecessary given DERs' inability to artificially suppress market prices. Mitigation would be unlikely given the fact that, as explained above, any state-jurisdictional revenues earned by the relevant DER would ultimately be factored into the Part B test. But to the extent that any DER *does* fail the Part B test, that would be a consequence of the fact that the test's 3-year time horizon is tailored to the economics of developing natural gas resources, and may not be appropriate for resources like energy storage which may rely on a

[11] DER Roadmap at 17.

longer-term payback to support project financing.[12] Thus, in this context, the cumbersome part B process would be more likely than not to over-mitigate and render rates unjust and unreasonable.

Given the administrative delays that would be inherent to any process to apply BSM to individual DERs and the lack of any demonstration of need to protect the market from manipulation by DER owners, NYISO should provide for a blanket exemption for these resources.

C. Failing to grant an exemption would set NYISO's capacity market on course to dysfunctionality and ultimately, dissolution.

Further, applying BSM to DERs would represent a step down a path to a dysfunctional capacity market that could ultimately lead to its collapse. As discussed at length in Clean Energy Advocates' protest to PJM's "jump ball" filing,[13] capacity markets have always been influenced by state policies. Allowing these state policies to influence prices provides for functional market outcomes and does not jeopardize the capacity market's ability to ensure resource adequacy.[14] By contrast, frustrating the ability of state-supported resources to sell in the capacity market ultimately causes customers to have to procure redundant capacity from other resources. It compromises the fundamental purpose of the capacity market by causing the region to exceed its installed reserve margin rather than procure the appropriate amount of resources.

DERs are one of many types of resources supported by New York state policies. New York's Clean Energy Standard sets the state on course to achieve 50 percent renewable energy

[12] A test with a 3-year time horizon is more appropriate for natural gas resources because they have relatively low up-front capital costs, coupled with longer-term fuel costs that are hedged by market prices. Were NYISO to proceed without granting a blanket exemption to DER resources, then its mandate to provide for just and reasonable rates would compel modifications to the Part B test with regard to DER that are financed using a payback schedule that is greater than 3 years, because proceeding without such modifications would result in over-mitigation.

[13] *See* Docket No. ER18-1314, Protest of Clean Energy Advocates (May 7, 2018).

[14] IPI report at 17-19.

supply by 2030. The Public Service Commission provides tier 1 renewable energy certificates for new renewable resources, and is currently considering compensation structures for offshore wind resources. It also supplies support to nuclear resources through its Zero Emissions Credit program, and compensates distributed clean energy resources for their environmental benefits through various policies included within utility rate cases

Were NYISO to set BSM rules in a way that ignores revenues from these programs, that would compromise the capacity markets' ability to incent the appropriate amount of resources to enter and remain in the NYISO market. In such a case, given the massive costs such an approach would impose on customers, the state would have an extremely strong incentive to protect customers by retaking control of resource adequacy and taking steps toward dissolving the mandatory obligation for load serving entities to purchase capacity from NYISO's market. By contrast, an approach that treats these revenues as legitimate will allow the capacity market to continue to serve its role of facilitating achievement of the appropriate installed reserve margin. NYISO should take the course that best harmonizes its markets with state policy. While NYISO's assessment of whether to apply BSM rules to DERs has immediate implications for only a small portion of its market, the underlying rationale of its decision implicates the ISO's broader stance toward the legitimacy of state policy-based revenue streams. In considering how to address DERs, NYISO should avoid setting a precedent that could more broadly compromise its ability to promote a functional market.

Institute *for* Policy Integrity

NEW YORK UNIVERSITY SCHOOL OF LAW

ELECTRICITY POLICY INSIGHTS

Capacity Markets and Externalities

Avoiding Unnecessary and Problematic Reforms

April 2018

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Executive Summary

Many states have recently ramped up efforts to address climate change and accelerate their transition toward cleaner energy sources. To achieve these goals, several states have adopted Renewable Energy Credits and Zero-Emission Credits. These policies pay generators for desirable attributes such as avoiding air pollution externalities associated with electricity generation from fossil-fuel-fired resources. These "externality payments" help level the playing field between emitting and non-emitting generators.

As these policies become increasingly prevalent, policymakers have begun debating whether the payments could negatively affect the efficiency of wholesale electricity markets. In particular, the debate has focused on whether these policies could reduce capacity prices to levels that no longer support economically efficient entry and exit of generators, and threaten resource adequacy. Consequently, various groups have proposed capacity market reforms, with the aim of shielding these markets from the potential price impact of externality payments. In March 2018, the Federal Energy Regulatory Commission approved ISO-New England's Competitive Auctions with the Sponsored Policy Resources proposal. And, in April 2018, PJM Interconnection filed two different proposals to reform its capacity markets with the Federal Energy Regulatory Commission.

But, as we discuss in this report, the premises underlying these reforms are faulty. First, the argument for redesigning capacity markets in reaction to externality payments relies on the argument that resources that get externality payments cannot be considered "economic," as they cannot be supported by only the revenue they earn in wholesale markets. But this argument focuses only on private generation costs, disregarding the market failures associated with the external costs of air pollution from fossil-fuel-fired resources. Externality payments help correct this market failure, and, therefore, they are expected to increase social welfare, improving the efficiency of entry and exit behavior of generators. The reforms will sustain the existing market inefficiencies.

Second, the justification for proposed reforms tends to overlook the role of inherent market forces. Capacity market prices, by design, adjust based on supply and demand. The proposed reforms largely disregard those adjustments, thereby failing to reach their self-proclaimed goal of restoring prices that would have resulted in the absence of externality payments. In addition, capacity market designs have their own flaws that might contribute to inefficiency, but those are unrelated to externality payments. Hence, there is no conclusive evidence that capacity markets are under threat or that any decrease in capacity market prices due to externality payments would be economically inefficient.

Rushed market design changes based on the unsupported assumption that state policies negatively affect capacity markets may actually harm the functioning of the markets, while potentially undoing states' efforts to combat pollution and climate change.

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Introduction

As states around the country ramp up efforts to address climate change and transition toward cleaner energy sources, many have relied on policy tools such as Renewable Energy Certificates (RECs) and Zero-Emission Credits (ZECs). These programs offer payments to resources for the value of generating energy that is associated with desirable attributes such as avoided carbon-dioxide emissions (externality payments). As a result of the increasing prevalence of such policies, policymakers have begun debating their potential effect on wholesale electricity markets.

Some commentators have argued that externality payments could distort capacity markets.[1] They maintain that these payments allow generators to bid into the capacity market at below the generators' costs of providing capacity, and allow generators that have received those payments to reduce the market-clearing price for capacity. By causing a reduction in capacity prices, they argue, the externality payments would send incorrect signals for the entry and exit of generators.[2] The argument maintains that those distortions would in turn lead to economically inefficient outcomes, resulting in elevated total costs of the system and potentially flawed functioning of the market by failing to ensure that enough capacity is present to meet demand at all times, threatening resource adequacy. Given such concerns, state and federal regulators, as well as other stakeholders, have started discussing the potential need to "accommodate" or "mitigate" the effect of states' environmental and public health policies (state policies) in the design of wholesale electricity markets.[3]

As a result of the discussions, proposals for capacity market reforms that would counteract the impact of the externality payments have emerged. For example, PJM Interconnection (PJM)—a Regional Transmission Organization (RTO) that coordinates the movement of wholesale electricity in all or parts of thirteen states and in the District of Columbia—has proposed two different models to reform capacity markets in order to counteract any potential effect of those externality payments.[4] ISO-New England (ISO-NE)—an independent, non-profit RTO, serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont—also proposed a capacity market reform that was approved by federal regulators in March 2018.[5]

But, as we discuss in this report, the premises underlying these proposals are faulty. For example, there is currently not sufficient evidence that the state policies designed to reduce emissions negatively affect the economic efficiency of capacity markets from a societal welfare perspective. On the contrary, rushed design changes may actually harm the functioning of the markets, while potentially undoing the states' efforts to combat pollution and climate change.

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1. *See generally* Monitoring Analytics, LLC., 2016 State of the Market Report for PJM (2017) [hereinafter "2016 State of the Market Report for PJM"], http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume2.pdf; Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 4 (2018); for some of the contributions to the discussions, *see* FERC Docket No. AD17-11-000, *State Policies and Wholesale Markets Operations* and FERC Docket No. ER18-619, ISO-*New England Inc.* [hereinafter "FERC Dockets"] (for comments, filings, and transcripts of technical conferences), https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=&View=L
2. *See generally* FERC Dockets, *supra* note 1.
3. *See generally* FERC Technical Conference, *State Policies and Wholesale Markets Operated by ISO New England Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C., Docket No. AD17-11-000*, FERC (May 1-2, 2017), https://www.ferc.gov/EventCalendar/EventDetails.aspx?ID=8663&CalType=%20&CalendarID=116&Date=&View=L (follow hyperlinks for "Transcript, May 1" and "Transcript, May 2").
4. PJM Interconnection, L.L.C., ER18-1314-000, Capacity Repricing or in the Alternative MOPR-Ex Proposal: Tariff Revisions to Address Impacts of State Public Policies on the PJM Capacity Market (2018) [hereinafter "PJM Filing"].
5. *See* Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205 (2018).

Externality payments are designed to correct market failures resulting from the external costs of pollution and help increase the overall economic efficiency of the market. Changes in capacity markets designed to counteract the effect of externality payments will have ripple effects on the electricity supply, and will negatively affect renewable resources. For example, the changes will likely increase available capacity, which—all else remaining equal—will reduce energy market prices and thus energy market revenue. This decrease in energy market prices would be especially worrisome for renewable and limited-duration resources that rely more heavily on energy market revenues than capacity market revenue, as these resources can be severely limited from participating in capacity markets.[6] Proposals that make it more difficult for non-emitting resources to clear in the regular capacity markets will additionally diminish capacity market revenue for any carbon-free generators that do participate, adding a second blow to their profitability.

Current capacity reform proposals would thus reverse that positive effect of externality payments on social welfare and allow the inefficiencies in wholesale electricity markets to continue—namely, the externalities associated with air pollution.

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[6] *See* Jennifer Chen, *Is Capacity Oversupply Too Much of a Good Thing?*, 34 Nat. Gas & Elec. 15 (2017), https://doi.org/10.1002/gas.22016.

Background: Electricity Markets, Efficiency, and Externalities

In most regions of the United States, electricity is first traded in wholesale markets before being sold and distributed to consumers—households and most of businesses—in retail markets. The wholesale markets are managed by regional oversight entities called RTOs and ISOs, and regulated by Federal Energy Regulatory Commission (FERC). Most wholesale market operators run markets for energy, capacity, and ancillary services.[7] Currently, there are seven ISOs/RTOs operating in the country,[8] with PJM running the nation's largest wholesale electricity market.

Energy markets

As electricity cannot yet be stored in an economically efficient manner in large quantities,[9] generation needs to be perfectly aligned at every instant with energy consumption, which is volatile and tends to vary during the day and between seasons.[10] To address this problem in the energy markets, the wholesale price for a megawatt-hour (MWh) of electricity is established through auctions based on supply offers submitted by generators and demand bids submitted by load-serving entities (LSEs) that serve end users. Hourly day-ahead auctions ensure that energy demand and supply can be balanced at low cost, leading to a significant variation in energy prices during the day. Real-time wholesale auctions further facilitate the alignment between energy supply and demand by correcting for any unforeseen changes in market conditions.

In the auctions, LSEs submit their demand bids based on the predicted electricity consumption of the end users, and generators submit their supply bids based on the cost of generating electricity. Resources that win the auction are said to "clear" the market. The generator with the lowest bid clears the market first, followed by the next cheapest, until demand is met. The wholesale energy price for all generators that clear the market is then determined by the bid of the last resource to clear the market, plus other charges necessary to reflect the operational constraints of the grid, such as congestion and energy losses. Where there are competitive bidders, this design creates an incentive to bid true marginal costs because generators look to submit their lowest possible bid, in order to maximize the chance of their bid being

7 The role of energy and capacity markets is explained below. Ancillary services encompass variety of operations beyond generation and transmission that help grid operators maintain a reliable electricity system, among others, maintaining the proper flow and direction of electricity, addressing imbalances between supply and demand, and facilitating the system recovery after a power system event. As the revenues from ancillary markets constitute only a small portion of revenue for generators, this report focuses on energy and capacity markets. *See* David B. Patton et al., 2016 State Of The Market Report For The New York Iso Markets, at 14 fig.1 (2017), http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Reports/Market_Monitoring_Unit_Reports/2016/NYISO_2016_SOM_Report_5-10-2017.pdf (for the typical distribution of revenue for generators).

8 The seven ISO/RTOs are: California independent system operator (CAISO), Electric Reliability Council of Texas (ERCOT), Midcontinent Independent System Operator, Inc. (MISO), ISO New England (ISO-NE), New York Independent System Operator (NYISO), PJM Interconnection (PJM), and Southwest Power Pool (SPP).

9 Recent progress in energy storage technologies is likely to decrease the need for instantaneous coordination of electricity generation and consumption. For an overview of the currently available technologies and their costs see Richard L. Revesz & Burcin Unel, *Managing the Future of the Electricity Grid: Energy Storage and Greenhouse Gas Emissions* (forthcoming), http://policyintegrity.org/files/publications/ReveszUnel_EnergyStorage.pdf.

10 Demand for electricity is low during the night. It starts to increase in the morning, and remains high through the day. It usually peaks in early evening when it is mostly used in individual households returning from work. The substantial seasonal differences in energy usage, on the other hand, are mostly due to the varying need for heating and air conditioning.

cleared, while at the same time recovering their marginal cost of generation.[11] By encouraging generators to bid their marginal costs, this auction design ensures that the private variable costs of producing the total electricity demanded at a given time and location is minimized.

Capacity markets

In some regions, such as the Northeast and Midwest, energy markets are complemented by capacity markets, in which generators can receive additional payments for committing to provide generation capacity at a certain time period. Capacity is measured in megawatts (MW) and reflects the generator's potential to reliably generate electricity during a certain period.

The existence of capacity markets sets electricity generation apart from most other sectors, where firms are rewarded only for their actual production and not for their ability to produce. Proponents of capacity markets argue that they are needed due to the unique features of electricity as a commodity, and some particularities of electricity market design that make it vulnerable to market failures.

First, electricity demand is considered to be price inelastic. In other words, end-users do not significantly alter their electricity demand as the wholesale prices change. One of the main reasons for this lack of response to price is that end users rarely observe wholesale electricity prices directly, as LSEs usually charge consumers flat rates as set by state regulators in rate cases. Therefore, even when wholesale market prices substantially increase, signaling the scarcity of energy generation, consumers do not receive this price signal and hence they do not adjust their energy usage. Consumers may thus demand more electricity than is feasible to generate at a given time, which can lead to blackouts.

Second, electricity markets are often haunted by a "missing money problem."[12] The problem refers to the idea that energy prices in competitive wholesale electricity markets do not adequately reflect the value of investment in generation needed to create a reliable electric supply.[13] Because electricity cannot be stored at a large scale, and electricity demand fluctuates significantly during the day and the year, sufficient capacity must be built to balance supply and demand reliably under any foreseeable demand conditions, in particular under maximum peak demand conditions (called "super-peak" demand).[14] However, super-peak demand, by definition, occurs during only a small number of hours per year (e.g., 10 hours per year).[15] It is only during those super-peak hours that the capacity is almost fully utilized. The fact that enough generation capacity must exist to meet the high demand during these times means that much of the generation capacity sits idle during the rest of the year. To be profitable enough to stay in the market, these generators must earn enough money on energy sales in the super-peak hours when they manage to clear the auction to cover both operations and maintenance costs, as well as their construction costs.[16]

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[11] Every unit that clears the auction receives the same price for a MWh of energy they supply at a given location. Submitting a bid higher than the marginal cost would imply that, if the energy price is higher than the marginal cost but lower than the bid, the generator misses the profits that it would otherwise make. On the other hand, if the generator bids below it marginal cost, it risks clearing an auction where the MWh price will not cover his variable costs of energy supply. Consequently, only those resources that can produce and deliver electricity below the market clearing price—the marginal cost—are dispatched.

[12] Michael Hogan, *Follow the Missing Money: Ensuring Reliability at Least Cost to Consumers in the Transition to a Low-Carbon Power System*, 30 Electr. J. 55 (2017).

[13] *See id.*

[14] The level of peak demand fluctuates around the year in a relatively predictable manner but sometimes may increase to unusually high values, mostly due to extreme weather conditions. *See* Paul L. Joskow, *Capacity Payments in Imperfect Electricity Markets: Need and Design*, 16 Util. Policy 159, 159–170 (2008).

[15] *See id.* at 160.

[16] *See id.* at 160.

While in theory it is possible for all generators, including the highest-cost generators, to recover their full costs in such a short time interval, in practice there are a number of reasons why this may not happen. Notably, there are price caps in wholesale electricity markets.[17] While such price caps may be justified because they help limit potential market-power concerns and protect consumers, they nonetheless create a distortion: electricity market prices do not accurately reflect demand for reliability during peak-demand hours, and thus might render it impossible for some generators necessary for meeting the peak demand, specifically peaker plants, to recover their investment costs.[18] Consequently, an energy-only market with price caps may induce too little new investment to meet the maximum energy demand during super-peak hours.

Third, system reliability is a public good and markets generally underprovide public goods.[19] During a blackout, no generator is able to sell energy. As a result, when a resource prevents a blackout, benefits accrue to all of the generators that would have been otherwise unable to sell power. Similarly, given that during a blackout no consumer can receive energy, consumers would benefit from a decrease in consumption of any consumer that can forestall any blackout. As with all public goods, electricity's reliability is likely to be undersupplied without intervention in the market.[20]

In light of these limitations, some regions have chosen to set up capacity markets to assure that sufficient capacity is built to satisfy demand and thus ensure reliability at any moment of the year.[21] ISOs/RTOs such as PJM and ISO-NE run these markets by using auctions. Generators submit their bids for making their capacity available whenever the energy market price reaches a certain threshold, usually defined by the electricity price cap.[22] Capacity auctions choose the generators with the lowest offers to meet the necessary level of capacity to ensure resource adequacy—capacity amounts that are close to the predicted maximum demand plus a reference reserve margin.[23] All of the cleared generators receive the same per-MW price, equal to the bid of the last-clearing generator.

These capacity payments supplement earnings in the energy market. As the payments reward capacity only in the amount related to maximum electricity demand, they create incentives for entry up to the point where additional capacity is no

[17] For example, the electricity markets run by PJM and NYISO caps the admissible offers at $2,000/MWh. However, to comply with FERC Order 831, PJM verifies bids above $1,000/MWh to ensure that they "reasonably [reflect] the associated resource's actual or expected costs prior to using that offer" before using them for calculation of the clearing price. *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators*, Order No. 831, FERC Stats. & Regs. ¶ 31,387 (2016) (cross-referenced at 157 FERC ¶ 61,115), order on reh'g and clarification, Order No. 831-A, 82 Fed. Reg. 53403 (Nov, 16, 2017), FERC Stats. & Regs. ¶ 31,394 (2017), https://www.ferc.gov/whats-new/comm-meet/2016/111716/E-2.pdf.

[18] Joskow, *supra* note 14, at 162.

[19] System reliability meets the conditions of a public good: it is both non-excludable and non-rivalrous from the perspective of generators and energy end-users. Non-excludability means that it is not possible to prevent individuals from enjoying the benefits of system reliability even if they do not pay for the reliability. Non-rivalry means that system reliability being enjoyed by some of the consumers and generators does not prevent others from enjoying it simultaneously. The technology, however, is eroding the non-excludability feature. *See* Hogan, *supra* note 12; *see* Malcolm Abbott, *Is the Security of Electricity Supply a Public Good?*, 14 Electr. J. 31 (2001) (for background on 'public goods').

[20] *See* Joskow, *supra* note 14, at 165.

[21] For example, PJM, NYISO and ISO-NE run mandatory capacity markets, at MISO the participation in the market is voluntary.

[22] This threshold is usually reached during the super-peak demand hours but could also be a result of some technical problems of some generators, weather conditions disrupting the transportation of energy from some generators, or a mixture of the factors. In such situations the electricity generation becomes scarce relative to the demand, and imbalance between power generation and power consumption may lead to a blackout.

[23] Demand in the capacity market is determined by an administratively defined downward sloping demand curve. This curve is designed to ensure adequate resources to meet expected operating needs. It is therefore is based on the super-peak demand adjusted by reference margins. Reference margins are published periodically by North American Reliability Corporation for individual regions. They dictate how much capacity needs to be obtained in excess of the predicted maximum capacity to serve as insurance against breakdowns in part of the system or sudden increases in energy demand (expressed in percentage terms, usually a value between 10 and 20%). *See M-1 Reserve Margins*, N. Am. Elec. Reliability Corp., http://www.nerc.com/pa/RAPA/ri/Pages/PlanningReserveMargin.aspx (last visited March 29, 2018).

longer needed. In this way, capacity markets ensure there is enough energy generation when it is most needed, thus meeting their basic purpose: ensuring resource adequacy. At the same time, if the total revenue an existing generator can earn is too low for the generator to be profitable, the market will give an exit signal to that generator.

Outcomes of energy and capacity markets are strongly interwoven. Generators have an incentive to bid their true net costs of staying in the capacity market because otherwise they could risk not clearing in the auction. For existing power plants, this incentive leads to them to bid the present value of their current and future costs, adjusted by expectations regarding all future profits from energy and capacity markets (known as the "net going forward cost"). The optimal bid of new entrants corresponds to the costs of building the plants, adjusted by all the expected future profits from energy and capacity markets.[24] Therefore, the resources that manage to make profits on the energy market and thereby (partly) cover their annualized fixed costs are willing to accept lower capacity payments. Holding all other things equal, higher prices on the energy market lead to lower bids in the capacity market. On the other hand, capacity markets affect the long–term composition of resources present in the market, and thus energy prices. The two markets therefore simultaneously affect each other.

Market failures and corrective subsidies

A key principle of economics is that competitive markets ordinarily maximize social welfare. And, any interference with the operation of a free market, if it changes the equilibrium price and quantity, reduces welfare. However, the assumption that competitive markets are economically efficient relies on idealized assumptions about the structure of the market.[25] Market failures often interfere with that ideal vision. For example, market outcomes are not efficient when market transactions fail to take into account the cost of damage they cause to third parties through a "negative externality."[26] Air pollution is a classic example of a negative externality. As a by-product of electric generation, fossil-fuel-fired power plants emit many pollutants such as nitrous oxides, sulfur dioxide, particulate matter, and ammonia.[27] The electricity sector is also one of the main sources of greenhouse gas emissions—29% of U.S. emissions in 2015.[28] All of these emissions harm society,[29] and wholesale electricity markets have been failing to take those external costs fully into account.[30] If polluters do not need to pay for the damages they cause, they will engage in market transactions that result in more pollution than is economically efficient.

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24 *See* James F. Wilson, *Forward Capacity Market CONEfusion*, 23 Electr. J. 25 (2010) (for the discussion on optimal bids).

25 For the set of conditions required for competitive equilibria to exist and be efficient see Antonio Villar, General Equilibrium with Increasing Returns 6 (1996) and Robert S. Pindyck & Daniel L. Rubinfeld, Microeconomics 315, 612-13 (7th ed. 2009). *See also* Bethany Davis Noll & Burcin Unel, *Markets, Externalities, and the Federal Power Act: The Federal Energy Regulatory Commission's Authority to Price Carbon Dioxide Emissions*, N.Y.U. Envtl. Law Rev. (forthcoming).

26 *See generally* Paul Krugman & Robin Wells, Microeconomics 437-438 (2d ed. 2009); Jonathan Gruber, Public Finance and Public Policy 136 (5th ed. 2016).

27 *See* Jaramillo & Muller, *infra* note 29.

28 U.S. EPA, EPA 430-P-17-001, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2015 (2017), https://www.epa.gov/sites/production/files/2017-02/documents/2017_complete_report.pdf.

29 For estimates of monetary damages due to air pollution exposure for $PM_{2.5}$, SO_2, NOx, NH_3, and VOC from electric power generation, oil and gas extraction, coal mining, and oil refineries for selected years see Paulina Jaramillo & Nicholas Z. Muller, *Air Pollution Emissions and Damages from Energy Production in the U.S.: 2002-2011*, 90 Energy Policy 202, 202–211 (2016) [for 2011 the paper estimates that damages associated with the investigated emissions totaled 131 billion dollars (in 2000$)]. *See also* Jeffrey Shrader, Burcin Unel & Avi Zevin, Valuing Pollution Reductions. How to Monetize Greenhouse Gas and Local Air Pollutant Reductions from Distributed Energy Resources (2018), http://policyintegrity.org/documents/valuing_pollution_reductions.pdf

30 RGGI permits which are obligatory for offsetting the CO_2 emissions for generators located in some of the states and are an exception here. However, their price level (currently around $3) is far below the external costs associated with emissions of the relevant greenhouse gases.

Whenever the market fails because of externalities, intervention is not just preferable but necessary to ensure that social welfare can be maximized.[31] The typically prescribed, efficient solution for an externality is a corrective tax, forcing the market participants to directly "internalize the externality"[32]—known as the "first-best" option—by, for example, imposing a "carbon price" in the form of an economy-wide emissions tax or cap-and-trade system based on the external damages caused by emissions.[33] However, taxation may not be feasible due to political considerations. As an alternative, policymakers can address negative externalities by subsidizing resources that do not produce the externality.[34] While such policies are generally inferior to taxing the externality directly, they can still substantially improve the economic efficiency of the market. These are known as "second-best" options.

Therefore, corrective subsidies, such as externality payments, that aim at increasing market efficiency in the presence of externalities are an important and desirable tool for policymakers. Corrective subsidies are clearly distinguishable from "traditional" rent-seeking subsidies that result from companies manipulating the social or political environment to increase their profits based on the personal preferences of decisionmakers for certain products, services, or technologies. These traditional subsidies that do not target any market failure reduce social welfare by distorting market allocations, as opposed to increasing social welfare by eliminating externalities.

The combined capacity, electricity and ancillary services markets have been mostly successful at providing reliable energy to consumers.[35] Nonetheless, because these markets have been disregarding a significant externality—pollution—they have failed to ensure that the energy mix is socially efficient.

The existence of externalities changes what can be considered economically efficient. A generating unit that appears to be profitable given its market revenue, and therefore economic when considering only its private costs, may actually be socially uneconomic when its emissions are taken into account because its net revenues are lower than the harm it causes.[36] Similarly, a generating unit that appears uneconomic based on its wholesale market revenues alone may nevertheless be socially economic and viable if it could capture the economic value of its environmental attributes through externality payments. Without incentives for the generators to consider the external costs of their actions, the equal treatment of emitting and non-emitting resources in wholesale markets causes too much electricity to be produced by emitting generators. As a result, energy markets currently do not yield economically efficient outcomes.

A carbon pricing policy, as explained above, would be the first-best economic approach to counteract the greenhouse gas emissions externality. This economically preferred policy takes into account the pollution intensity of the generators,

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31 Elena Cima, *Caught Between WTO Rules and Climate Change: The Economic Rationale of "Green" Subsidies*, 4 Environ. Law Econ. 379 (2017).

32 *See id.*

33 While this report discusses only the externalities related to greenhouse gas emissions, the same principles applies to other pollutants such as nitrous oxides, sulfur dioxide, particulate matter as well.

34 Gruber, *supra* note 26, at 138.

35 In 2015, municipal utility customers experienced on average one outage and about two hours of interrupted service, investor-owned utilities' customers averaged slightly more than three hours without electric service, while co-op customers averaged nearly five hours without power over two outage events. David Darling & Sara Hoff, *Annual Electric Power Industry Report* (EIA-861), U.S. Energy Info. Admin. (Sept. 16, 2016), https://www.eia.gov/todayinenergy/detail.php?id=27892.

36 The phrase "uneconomic" generators has been used in the discussions around the capacity market reforms. While not explicitly explained, it relates to being able to successfully compete in the market and clear the market auctions based on their private costs. *See* Order on Paper Hearing and Order on Rehearing, *ISO New England Inc.*, 135 FERC ¶ 61,029, P 170 (2011) ("Our concern, however, is where pursuit of [states'] policy interests allows uneconomic entry of OOM capacity into the capacity market that is subject to our jurisdiction, with the effect of suppressing capacity prices in those markets.").

sending differentiated price signals to all market participants. This policy would not affect the marginal cost of non-polluting resources, would cause a small increase in the marginal costs of relatively clean sources, and would lead to a large increase in the marginal costs of highly carbon-intensive generators. In other words, the more emissions a resource produces, the more it needs to pay, which reduces its profits. This inevitably leads to a change in the composition of generation capacity, with a fraction of the most emissions-intensive resources pushed to exit the market. At the same time, it would induce entry from cleaner resources.

Importantly, the generation mix reached when emissions taxes or cap-and-trade programs that fully internalize the externalities are implemented is socially efficient because such programs minimize the sum of generators' costs necessary to meet demand given the existing fleet of generators and the external cost associated with this level of electricity production. These policy tools also ensure that the generators face economically efficient incentives for exit and entry, which necessarily reflect the cost of the emissions.

Yet, despite imposing external costs, fossil-fuel-fired resources have been receiving the exact same compensation in wholesale markets for supplying electricity as non-emitting resources. As country-level initiatives to correct that problem have been absent so far, many states have taken the lead in tackling the electricity-related externalities. However, the first-best solutions—an economy-wide emission tax or cap-and-trade program—are often not feasible for states. Consequently, states face the difficult task of choosing the economic instruments necessary to address externalities within the policy tools available to them. Some states have opted to introduce payments for the carbon-free electricity generation by requiring utility companies to buy RECs or ZECs from renewable or zero-emission resources for a certain percentage of their load. By introducing payments that are related to the value of avoided emissions, these policies are an attempt to ensure that the difference in revenues between clean and polluting generators account for the external costs.

Externality Payments Have Not Led to a Need for Capacity Market Reforms

Several ISOs/RTOs are in the process of changing their capacity markets in reaction to state policies that include externality payments. For example, PJM, the nation's largest RTO, recently submitted two proposals to FERC,[37] and ISO-NE recently received approval for a reform.[38] Both PJM and ISO-NE aim to reduce any potential impact that externality payments might have on capacity markets by increasing the market clearing price in these markets.

The proposed changes are all based on the premise that state externality payments allow generators that would otherwise not be profitable, or what ISOs/RTOs call "uneconomic," to enter the market with below-cost bids, causing the "more efficient, lower cost generators" to exit and "more expensive, less efficient generators" to stay "which will ultimately lead to higher costs for consumers."[39] Under this theory, any prices that are affected by externality payments are not competitive, but rather below competitive levels.[40] And, the theory maintains that such prices would distort entry and exit decisions by allowing uneconomic resources to enter or stay, and economic resources to exit.[41] Additionally, these ISOs/RTOs suggest that the capacity prices could settle at levels that are too low to attract new capacity not encompassed by externality payment programs[42] and, in the long term, could threaten resource adequacy.[43]

Externality payments, such as ZECs and RECs, reward the electricity production of certain resources, and in that way they affect outcomes in capacity markets. For example, externality payments may create incentives to install non-emitting generating capacity that meets state environmental objectives, and these resources would not be profitable without these payments. Entry of such new resources changes capacity prices and thereby affects entry and exit considerations for other generators. Externality payments can also affect exit and entry through changes to revenues in energy markets induced by new non-emitting generators. But, it is important to keep in mind that internalizing externalities improves economic efficiency. And, while detrimental welfare effects of externality payments on capacity markets are theoretically

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37 PJM Filing, *supra* note 4.

38 Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 2 (2018).

39 *Pre-Technical Conference Comments, Robert C. Flexton, President & CEO, Dynegy Inc., Docket No. AD17-11-000*, FERC (Apr. 13, 2017), https://www.ferc.gov/CalendarFiles/20170426151233-Flexon,%20Dynegy.pdf.

40 *ISO New England Inc.*, 162 FERC ¶ 61,205, P 4 (2018).

41 The suggestion of externality payments negatively affecting the entry and exit decisions has been brought forward, among others, by ISO New England in its white paper stating that "the participation of resources with out-of-market contract revenue (…) depress capacity prices for all other capacity resources for many years. Further, this potential may impair the market's ability to attract new, competitively-compensated resources when they are needed ISO-NE." ISO New England, Competitive Auctions with Subsidized Policy Resources 6 (2017), https://www.iso-ne.com/static-assets/documents/2017/04/caspr_discussion_paper_april_14_2017.pdf. FERC explained in approving ISO-NE's change, "[a]ccording to ISO-NE, these out-of-market actions could result in price suppression and thus negatively impact the market's ability to retain and justly compensate needed existing resources and to attract new, competitively-compensated resources." Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 17 (2018); accord. PJM Filing, *supra* note 4.

42 Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 4 (2018).

43 According to ISO-NE, it favored this objective "because FCM's capacity clearing price guides competitive entry and exit decisions for the region," and therefore "is essential to achieving the region's resource adequacy over the long term." *ISO New England Inc.*, 162 FERC ¶ 61,205, P 32 (2018).

possible,[44] it is far from clear whether externality payments indeed have such detrimental effects on capacity markets, as we discuss in the remainder of this report.

Before implementing reforms of the capacity market reforms under the Federal Power Act, market operators[45] must demonstrate to FERC that any rates they propose to charge for interstate electricity are just and reasonable.[46] In order to satisfy the just and reasonable standard and avoid needlessly causing inefficiencies, ISOs/RTOs need to base their decisions on economic findings pertaining to their markets when altering their market designs. In addition, given the long lifespan of power generation assets, any unreasoned alteration in market design rules has the potential to result in a long period of inefficient outcomes. While there has been a substantial discussion around state policies and the functioning of wholesale markets,[47] both comprehensive economic modeling and empirical evidence are necessary to sufficiently demonstrate any destabilization of markets.

But there is currently no such evidence that externality payments threaten the efficient functioning of capacity markets, or that these capacity markets require reform. First, the argument for reforming capacity markets in reaction to externality payments focuses only on private generation costs, disregarding the external cost of electricity generation that is being addressed by the externality payments. This approach leads the proponents of reform to incorrectly identify which generators are economic and which are not, and they incorrectly claim that any price effect of externality payments would be inefficient. Second, the arguments for proposed reforms overlook the effect of the inherent market forces of capacity markets that, by design, would lead to price adjustments based on the supply and demand conditions in the market. Proponents of reform then incorrectly claim that externality payments would threaten either the functioning of the market or resource adequacy. And, finally, the arguments disregard the other important flaws of capacity markets that need to be addressed.

Externality payments help correct market failures and improve economic efficiency

As explained above, the external costs that electricity generation imposes on society are usually not priced in the energy markets. When such external costs, such as carbon emissions, are present, they should be taken into account when deciding whether or how much a resource should be used. Externality payments for generators' desirable attributes force the market to consider the external costs of various resources.

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44 PJM's Market Monitor has explained that ZECs "are not part of the PJM market design but nonetheless threaten the foundations of the PJM capacity market as well as the competitiveness of PJM markets overall" and that "[t]he current subsidies demonstrate that the markets need protection against subsidized, noncompetitive offers from existing as well as new resources." 2016 State of the Market Report for PJM, *supra* note 1, at 37. David Patton, the President of Potomac Economics Ltd., was more cautious when discussing the relevant state policies, acknowledging that "[s]ubsidized entry in itself is not necessarily problematic. For example, if subsidized entry simply displaces non-subsidized entry in similar quantities, it would have little effect on market prices, holding all else constant. Therefore, the problem is largely one of coordination and avoiding sustained disequilibrium conditions (i.e., capacity surpluses caused by the subsidized entry)." *Comments of David B. Patton, Ph.D., Regarding State Policies Affecting Eastern RTOs, Docket No. AD17-11-000*, FERC (Apr. 24, 2017), https://www.ferc.gov/CalendarFiles/20170426150115-Patton, Potomac Economics.pdf. In ISO New England some stakeholders expressed concern that allowing state-subsidized resources to participate in capacity markets without subjecting them to a minimum offer price rule could threaten the financial viability of other resources. *See* Sarah K. Adair & Franz T. Litz, Understanding the Interaction between Regional Electricity Markets and State Policies 9 (2017).

45 Federal Power Act, 16 U.S.C. §§ 791-828(c), at § 824(e) (2010 & supp. 2010).

46 *Id.* § 824d(a).

47 For some of the contributions to the discussions, see FERC Dockets, *supra* note 1.

In particular, when a generator that would not have cleared an auction without a ZEC- or REC-style payment is able submit a bid that allows it to clear after the introduction of such a program, it does not imply that the payments distort competition or efficiency. Rather, it suggests that the presence of the generator is socially desirable when external attributes are considered. State policies that are directly related to socially desirable attributes should be seen as instruments that help fix this market failure and level the playing field. These payments introduce a difference in revenues between clean and emitting generators that aim to approximate the revenue that the resources would have gotten if the external costs of pollution were taken into account in the energy market. As such, a policy offering payments for clean attributes does not distort the market outcome but rather moves the market towards more economically efficient outcomes from a societal perspective.

It is a misguided approach to treat externality payments like distortive, rent-seeking subsidies that simply provide financial aid to a group of producers without being directly tied to a quantifiable external benefit. This misunderstanding may stem from the tendency to focus only on private costs when defining what it means to be an "economic" resource. Generators that receive externality payments, and clear the market, are indeed economic when considered from the perspective of overall social welfare. Even if externality payments are second-best policies, their corrective effects are desirable given the high external costs emitting resources impose on society.

Given that external costs of emissions are currently not fully internalized in markets, the external costs of externalities and, hence the level of existing market distortion can be very substantial. For example, the annual external damages associated with the climate change damages from CO_2 emissions of a typical 1,000 MW coal plant, not taking into account damages from other pollutants, would amount to about $234.3 million[48] based on the Interagency Working Group's Social Cost Carbon.[49] In comparison, PJM forecasted that a 1,000 MW seller in one of their areas would see its capacity market revenue reduced by $6.75 million annually given the effect of externality payments, a negligible amount compared to their external costs.[50] The external costs of emissions therefore starkly outweigh the reduction in generators' revenue, and suggest that the market signals sent by externality payments guide the generation mix in the right direction. Therefore, externality payments help correct existing market distortions, rather than exacerbate them. And misguided adjustments to capacity markets may cancel out those corrective effects.

Well-designed externality payments create changes in the generation mix that are similar to those induced by first-best pollution taxes. A first-best emissions tax would increase the marginal costs of energy generation of polluting units based on the external damages they cause, forcing them to bid higher in both energy and capacity markets. The average energy

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[48] An average coal plant operated with a 53.5% capacity factor in 2017. Electric Power Monthly, U.S. Energy Info. Admin. (2018), https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_6_07_a (last visited Apr. 24, 2018). A typical coal plant has an average emission rate of 1 ton/MWh. Therefore, a 1,000 MW coal plant would produce 1,000*8760*53.5%= 4,686,600 MWh of electricity and about 4,686,600 tons of carbon dioxide. The monetary damages of these emissions equal to $234,300,000 in 2017 dollars using the Interagency Working Group's Social Cost of Carbon value of about $50 per ton in 2017 dollars. *See* Interagency Working Group on Social Cost of Greenhouse Gases, Technical Support Document: *Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866*, at 16 (2016).

[49] The Social Cost of Carbon measures and monetizes the damage that results from emission of a ton of CO_2 into the atmosphere. The Interagency Working Group's (IWG) 2016 Social Cost of Carbon estimate is the best currently available estimate for the external cost of CO_2 emissions. IWG's methodology has been repeatedly endorsed by reviewers. In 2014, the U.S. Government Accountability Office concluded that IWG had followed a "consensus-based" approach, relied on peer-reviewed academic literature, disclosed relevant limitations, and adequately planned to incorporate new information through public comments and updated research. *See* Gov't Accountability Office, GAO-14-663, Regulatory Impact Analysis: Development of Social Cost of Carbon Estimates 12-19 (2014), http://www.gao.gov/assets/670/665016.pdf.

[50] PJM Filing, *supra* note 4, *Attach. E, Aff. of Adam J. Keech*, at 3.

price would increase, but generators with higher emissions would clear the auctions less frequently and, when they clear, the most pollution-intensive resources would earn less per MWh. For example, under a first-best carbon pricing policy, the 1000 MW coal generator above would need to pay a tax equal to the damages it causes—the Social Cost of Carbon—and, hence, would face even a strong exit signal. Consequently, just as is the case with externality payments, profits fall for emitting resources to the point that some may be forced to exit the market.

The generators that leave the market under a pollution tax, but would not have left otherwise, are currently being classified as "economic" in many policy discussions. However, they are socially uneconomic when external costs are considered. Clean resources, on the other hand, do not need to increase their bids under pollution taxes or payment programs, because their marginal costs are unaffected. Therefore, they would clear the auctions more often and would receive higher prices for their generation. Consequently, their profits rise, which also leads to increased entry and slower exit of non-polluting resources, just as with the externality payments.[51]

Externality payments may increase the economic efficiency of entry and exit behavior

As discussed above, capacity market prices and energy market prices are interrelated. Because prices in energy markets are distorted due to negative externalities, current capacity prices are distorted as well. Thus, deviating from the prices that would have occurred without state policies does not automatically imply a worse outcome in terms of social welfare, and, thus, economic efficiency. Rather, if we measure from the perspective of overall societal welfare, those deviations would reflect better outcomes because the external cost of emissions would be partially internalized. After all, the introduction of first-best taxation of externalities—which, by definition, would lead to a socially efficient generation mix—would also lead to lower revenues for emitting resources and, thus, faster exit of those resources.

Externality payments are meant to improve price signals by supplementing the revenue of generators that offer societal benefits through their lack of emissions. They indirectly affect the profitability of polluting resources, both through energy markets and capacity markets. Polluting resources also enter less frequently and exit quicker than under a policy scenario without externality payments. This might in particular apply to coal- and oil-fired plants given their pollution intensity.[52] Indeed, the exit of the most polluting resources would likely be even higher under the first-best policy of emissions taxes. On the other hand, the prospect of additional revenues from the externality payments cause clean generators to bid lower than they otherwise would in wholesale energy markets, and make some new resources enter the market that otherwise

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[51] The similarity in the outcomes under taxation of externalities and payments to avoid externalities can be seen by analyzing a simple case of inelastic demand, one type of emitting generator and payments for attributes set at the value of avoided emissions. Here, the two policies are indistinguishable from the perspective of the generators as they lead to the same profits at the equilibrium. Let t denote the corrective tax rate, s the payment for clean attribute, x the amount of clean generation, y the amount of dirty generation, $MC_x(x)$ and $MC_y(y)$ the aggregate supply curves associated with the two types of generation, and *ext* the value of avoided emissions. The market solution under optimal tax is characterized by conditions: $x^t+y^t=Q$ and $MC_x(x^t)=MC_y(y^t)+t$. On the other hand, with payments for attributes the market will generate electricity such that: $x^s+y^s=Q$ and $MC_x(x^s)-s=MC_y(y^s)$. Whenever payment for clean attributes are set at the value of avoided pollution ($s=t=ext$) the solutions of those equations are the same: $x^s=x^t=x^*$ and $y^s=y^t=y^*$. As the market price in the tax case differs from the market price with payments for attributes by value of avoided emissions: $p^t=MC_x(x^*)=ps+ext$, the achieved profits are the same no matter which of the policies gets implemented. Consequently, as the two regimes are undistinguishable for generators in any period, their effect on dynamic incentives for entry and exit (and, thus, the capacity market) will also be the same. Clearly, in such a case the payments for attributes send exactly right signals to the resources. The current conditions at the energy market do not exactly match the conditions for profit equivalency described above. However, the results convey the intuition for similarities between corrective taxes and payments for attributes and can be seen as approximation of the actual outcomes.

[52] *See* Shrader, Unel & Zevin, *supra* note 29.

would not have entered. Therefore, the increased exit of some types of resources and the increased entry of others types of resources does not necessarily imply that the market is failing.[53]

Claims about distorted entry and exit generally remain vague about what exactly constitutes economic inefficiency and how to measure and compare it across different outcomes. These claims mostly rely on the differences in the types of resources that would enter and exit with state policies compared to the status quo.[54] However, it is not clear that externality payments decrease the economic efficiency of entry and exit behavior compared to a business-as-usual scenario. As we show below, establishing whether the entry of a given generator combined with the exit of another specific resource is more efficient compared to the status quo may be a challenging task. Even determining which of two possible entrants is more efficient from a societal point of view can be difficult.

Given that consumers' demand for electricity is largely fixed and the electricity market is competitive, choosing a socially efficient mix of generation resources is equivalent to picking a generation mix that minimizes the total social costs associated with energy generation, while maintaining the reliability of the system. To establish the true social cost of an existing resource, one needs to consider at least four types of costs associated with it: the marginal costs of energy generation, power plant cycling costs,[55] yearly operation and maintenance costs independent of generation, and costs associated with externalities. For new resources, the construction costs are also relevant.

Engineering literature uses a concept called "Screening Curves" to identify the socially efficient composition of generators. These curves show the average cost of using a plant's capacity to summarize the different types of costs, except for externalities.[56] One important lesson from engineering literature studies is that there is no one superior type of generator that is the most-efficient under every setting, but rather, the socially efficient choice of a new resource depends on many factors. For instance, a high-marginal-cost, low-fixed-cost resource will be less costly to operate than a resource with a low-marginal-cost, high-fixed-cost when both are expected to operate for a relatively low number of hours (at low capacity factors).[57] In other words, for defining what is "efficient," the totality of factors, including the properties of the existing generation mix, and, thus the capacity factors, must be considered.[58] In particular, a simple comparison of marginal generation costs, or going forward costs, will not make clear which generators are socially desirable.

Panel A in Figure 1 shows the private annual average cost of capacity usage for three types of generators dependent on their capacity factor. The costs are composed of the generators' annual fixed costs, given by the y-intercept, and variable costs, given by the slope of the screening curves.[59] In relative terms, the Gas Turbine (GT) generates power at the lowest

[53] However, current externality payments disregard the pollution intensity of dirty resources. Consequently, these policies treat all polluting power plants the same way, while the first-best policy would have sent stronger negative signals for coal and oil-fired power plants than for gas generators. In other words, with the current system of externality payments, some gas generators might be likely to exit slightly too early and enter too little while coal plants might exit too slowly and enter too much, compared to the socially efficient outcome.

[54] Given that externality payments are not first-best policy tools to internalize environmental and public health externalities, there may be some dynamic inefficiencies associated with them.

[55] Cycling operations include on/off startup and shutdown operations, on-load cycling, and high frequency MW changes for automatic generation control.

[56] *See* Steven Stoft, Power System Economics: Designing Markets for Electricity (2002); Yusuf Emre Güner, *The Improved Screening Curve Method Regarding Existing Units*, 264 Eur. J. Oper. Res. 310, 310–326 (2018).

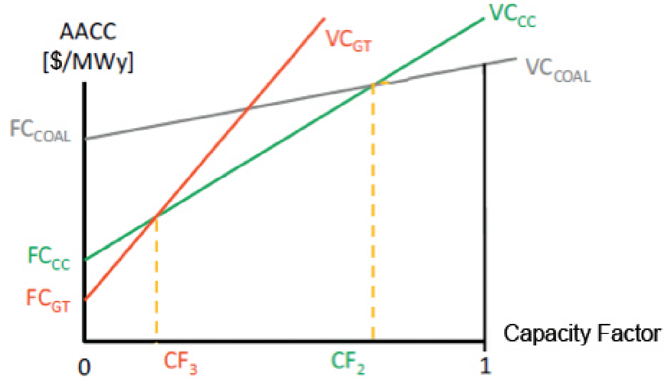
[57] For the intuition see Güner, *supra* note 56, at 311-312

[58] The amount of existing capacity as well as the proportion of generators of various types will determine how often a new resource of a certain category will be able to clear the energy market. This information can be summarized in form of capacity factor - the fraction of a generator's potential output that is actually produced. *See* Stoft, *supra* note 56, at 36.

[59] For the purposes of simplicity, the basic screening curves methodology is presented here that, for example, does not take into account dynamics of a power market.

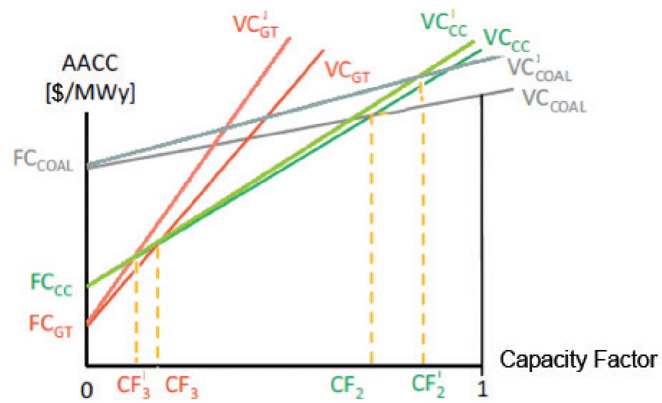
costs among the other two if the power plant is run less than a certain amount of capacity factor, CF_3, annually. The Coal power plant would be the preferred choice if the new power plant is expected to operate actively over a capacity factor of CF_2. The Combined Cycle (CC) power plant is cost-effective if it runs at a capacity factor that is between CF_3 and CF_2.

Figure 1: Comparison of screening curves for various resources



Panel A: Classical screening curve

Source: Figure 1 adapted from Yusuf Emre Güner, *The Improved Screening Curve Method Regarding Existing Units,* 264 EUR. J. OPER. RES. 310, 312, fig.2 (2018).



Panel B: Screening curves enhanced to reflect external costs.

Source: Authors' adaptation of screening curves

When external damages associated with individual power plants are considered, the socially efficient generation mix changes. In Panel B, new screening curves reflect the social screening curves. Adding the external costs of pollution increases the marginal cost of production and, thus, rotates the screening curves outwards. The degree of rotation is smaller for cleaner generators and higher for dirtier generators. Here the CC power plant is depicted as having the lowest external damages, with the coal plant having the highest external damages. With the shift in curves, the thresholds for choosing the cost-efficient generators change. The "cleaner" CC generator is now the preferred resource for a wider range of capacity factors.

As is clear from the comparison of Panels A and B, focusing solely on marginal private costs in an analysis to determine what type of new generation is socially efficient would lead to misleading conclusions. A well-functioning capacity market would automatically induce efficient entry and exit of the resources. However, the current market design disregards externality costs, and thus cannot currently incentivize socially efficient entry and exit.

There is no credible evidence that externality payments threaten the viability of markets

Concerns that externality payments would inefficiently suppress capacity market prices, and that the resulting price changes would undermine the viability of markets, have been at the heart of the arguments in favor of capacity market redesign. But, currently there is no empirical support for this argument. Any price effect of externality is likely to be modest, especially in comparison to historical price fluctuations observed in the market and the social welfare gained from avoided emissions. In fact, given the interconnected nature of energy and capacity markets, and that other generators would also adjust their bids, clearing prices might even increase under some conditions. In addition, capacity markets prices would, by design, adjust to meet the resource adequacy requirements if capacity was indeed scarce. Past evidence also shows that capacity markets have consistently achieved their goals of resource adequacy despite a plethora of subsidies and steep price fluctuations.

The actual effect of externality payments on capacity prices is likely to be rather modest for two reasons. First, not all resources receiving externality payments participate in capacity auctions. In some regions, like PJM, stringent capacity performance standards require bidding generators to guarantee sustained operation on an annual basis. Because renewable resources are seasonal, they would be unable to bid into capacity markets that have those restrictions. Externality payments to these resources consequently have only an indirect impact on capacity price formation—through the outcomes on energy markets.[60] Similarly, in ISO-New England, Minimum Offer Price Rules have been in place to prevent resources that receive externality payments from affecting the capacity market price.[61]

Second, even if resources that receive externality payments could participate in capacity markets, they would be limited in their ability to reduce capacity market prices. Any decrease in the bid of an infra-marginal unit that would have cleared the auction anyway, all else equal, would not affect the market clearing price. Thus, externality payments can affect the auction price only in limited situations: (1) when they induce entry (or prevent exit), increasing available supply of capacity, and hence lowering the market clearing price; or (2) when they directly lower the marginal bid, and hence the market clearing price.[62] For example, if the market clearing price were $40/MW, and if a resource that would normally bid $30/MW decreases its bid to $10/MW due to externality payments, the reduction in that resource's bid would not change the market clearing price.

Furthermore, given the interconnected nature of energy and capacity markets, even the direction of the net effect of the externality payments on capacity market prices is not clear. Polluting resources may submit higher bids than they would otherwise due to the prospect of decreased revenues from the energy market. Given that in some regions such polluting resources are more likely to be the marginal bidders in the capacity markets than the resources that get externality payments, the market clearing price in those regions might even increase depending on the resource mix of the area. Therefore, any forecasting exercise that adjusts the bids only for resources that get externality payments, or simulates auctions by only adding zero- or relatively low-priced supply bids without adjusting the other bids, is not sufficient to inform decisionmaking.

The actual outcomes in capacity markets also do not support claims that low or significantly-fluctuating prices do not send efficient incentives for entry, among others, to units that are not eligible for externality payments. States have long been using externality payments, and capacity prices have been fluctuating substantially since the introduction of the

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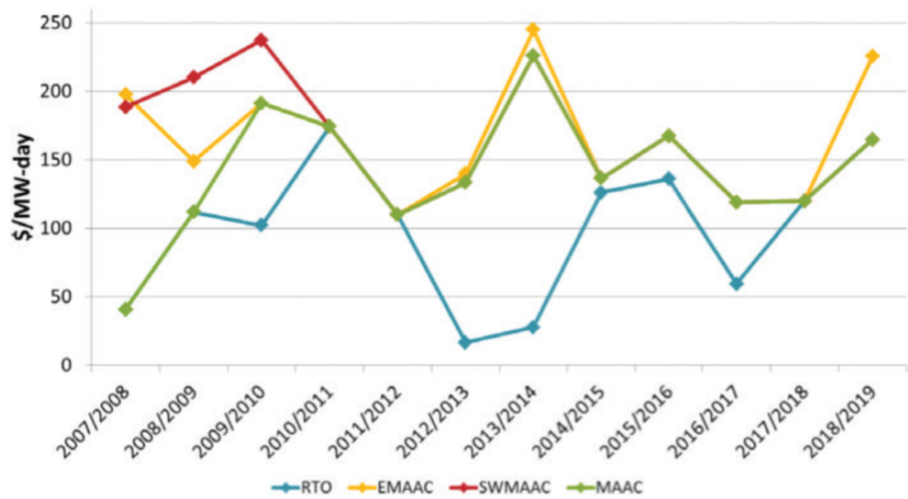
60 For instance, from delivery year 2020/2021 PJM allows the resources only to bid under Capacity Performance standard which requires them to be able to sustain availability throughout the delivery year. In the first auction under the capacity performance standards only held in May 2017 wind and solar constituted only about 2 percent of capacity cleared. For analysis of the bidding results *see* Jeff St. John, *PJM's Latest Capacity Auction: A Tough Market for Nuclear and Demand Response*, GreenTech Media (May 24, 2017), https://www.greentechmedia.com/articles/read/pjms-capacity-auction-a-poor-showing-for-nuclear-and-demand-response#gs.uwVJzdo.

61 An exemption was granted for 200 MW of renewable resources a year (or up to 600 MW if the exemption was not completely used in the previous two auctions).

62 An externality payment might directly lower the marginal bid if it decreases either the bid of the unit that would be marginal without the payments or the bid of a units that would not clear the capacity auction without the payments.

capacity markets.[63] For example, the clearing prices in the PJM market, known as the Reliability Pricing Model (RPM), have varied widely since 2007 when the market was created. They started at $40.80 for delivery year 2007/2008 in the RPM Base Residual Auction, and have since fluctuated between $174 and $16.40 (see Figure 2). The last PJM auction featured a drop from $100 to $76.53.[64] Given the prevalence of such fluctuations in the market, it is very difficult to ascribe the cause of any changes in capacity prices to any one factor, without a proper econometric analysis. And, without a proper econometric analysis, it is hard to isolate whether capacity price fluctuations are due to state policies or to other changes in market conditions.

Figure 2: RPM Base Residual Auction Resource Clearing Prices within PJM over time and by sub-region (LDA)



Source: http://www.nrel.gov/docs/fy16osti/65491.pdf, p. 11.[65]

But, despite all of these fluctuations, a significant amount of new generation capacity continues to clear capacity actions. This is contrary to the argument that capacity markets are under threat. In PJM, for example, almost 3,000 MWs of new capacity, mostly in the form of new or uprates to existing gas-fired combustion turbine and combined cycle generation

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63 Short lead time between the capacity auction and the delivery year could also lead to price fluctuations. A long lead time allows more types of resources to respond through entry to unexpected changes in capacity prices. Similarly, with a longer lead time, any possible effects of the externality payments will be smoothed out over time. But if a major plant announces plans to unexpectedly exit the market, in the next capacity delivery year, only certain types of power plants can be built in time to replace it and prices may fluctuate during that period. The amount of time needed to build a power plant varies by technology. For instance, the average construction time for nuclear reactors in the US has been 9.3 years, constructing coal power plants takes around four years and gas-fired power two to three years. *See* Michel Berthélemy & Lina Escobar Rangel, *Nuclear Reactors' Construction Costs: The Role of Lead-Time, Standardization and Technological Progress*, 82 Energy Policy 118 (2015). For instance, the average construction time for nuclear reactors in the US has been 9.3 years, constructing coal power plants takes around four years and gas-fired power two to three years. *See id.* at 20, tbl.4 ; *see* Executive Summary of *Projected Costs of Generating Electricity*, IEA, www.iea.org/textbase/npsum/ElecCostSUM.pdf (last visited Apr. 11, 2018).

64 *See* PJM, 2020/2021 RPM Base Residual Auction Results PJM #5154776 (2017) [hereinafter "PJM 2020/2021 RPM Base Residual Auction Results"], http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2020-2021-base-residual-auction-report.ashx (summarizing results of auction).

65 Thomas Jenkin et al., Nat. Renewable Energy Lab., NREL/TP-6A20-65491, Capacity Payments in Restructured Markets under Low and High Penetration Levels of Renewable Energy 12 (2016), http://www.nrel.gov/docs/fy16osti/65491.pdf.

units, cleared in the base residual auction for the 2018/2019 delivery year, nearly 5,400 MWs cleared for the 2019/2020 delivery year, and roughly 2,400 MWs cleared for the 2020/2021 delivery year.[66]

Importantly, capacity markets have co-existed for years with many different subsidies, both corrective and distortive, without leading to similar resource-adequacy fears. For example, fossil-fuel generators benefit from numerous federal tax deductions, including deductions for intangible drilling costs and for investment depletion related to oil and natural gas wells. In 2015, the U.S. government estimated that these subsidies amounted to $4.7 billion in reduced government revenue annually.[67] Additionally, many states have tax provisions in place that favor fossil fuels. For instance, Kentucky offers tax credits to electric-power entities operating coal-fired electric generation plants, alternative fuel facilities, or gasification facilities.[68] In Pennsylvania, the purchase or use of coal is exempt from the sales and use tax normally levied on sales of most goods and services in that state.[69] Independent reports quantifying federal and state fossil-fuel subsidies also tend to find substantial numbers.[70]

These subsidies similarly alter the outcomes of the wholesale markets, by lowering the revenue resources needed from the capacity markets. Yet, the effects of these non-market-payments on capacity markets have scarcely been discussed. Any change in market design in response to externality payments must be accompanied by an explanation for the different treatment of externality payments and fossil-fuel subsidies.

By design, capacity market prices would adjust to ensure resource adequacy

Another basis cited for reforming capacity markets has been that externality payments threaten resource adequacy. But, as we show below, externality payments do not pose any challenge for capacity markets fulfilling their main function. Even if the payments reduce the capacity prices, which, as we argue above, is not necessarily inefficient, they would still not undermine resource adequacy because of the design of the capacity markets.

Figure 3 shows a simplified depiction of PJM's capacity market. It presents the capacity supply curve and the capacity demand curve, called Variable Resource Requirement Curve. Because capacity demand is set by PJM, when PJM keeps the demand unchanged, the market clearing capacity price can decrease only if the supply of capacity increases and shifts the curve out as indicated by red arrows in Figure 2. In the context of externality payments, such a shift may happen if

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66 Organization of PJM States, Inc. (OPSI), Recommendation that the PJM Board of Directors not Approve PJM Staff's Repricing Proposal for Filing at FERC (2018), https://citizensutilityboard.org/wp-content/uploads/2018/02/OPSI-BOD-Repricing-Letter-Final-with-vote.February.pdf; PJM, 2018/2019 RPM Base Residual Auction Results PJM #5154776, http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2018-2019-base-residual-auction-report.ashx (last visited Apr. 24, 2018); PJM 2020/2021 RPM Base Residual Auction Results, *supra* note 64.

67 The number represents a nominal annual average figure based on the 10-year revenue estimate. *See* U.S. Office of Mgmt. & Budget, Progress Report on Fossil Fuel Subsidies, *available at* https://www.treasury.gov/open/Documents/USA%20FFSR%20progress%20report%20to%20G20%202014%20Final.pdf (last visited Mar. 29, 2018).

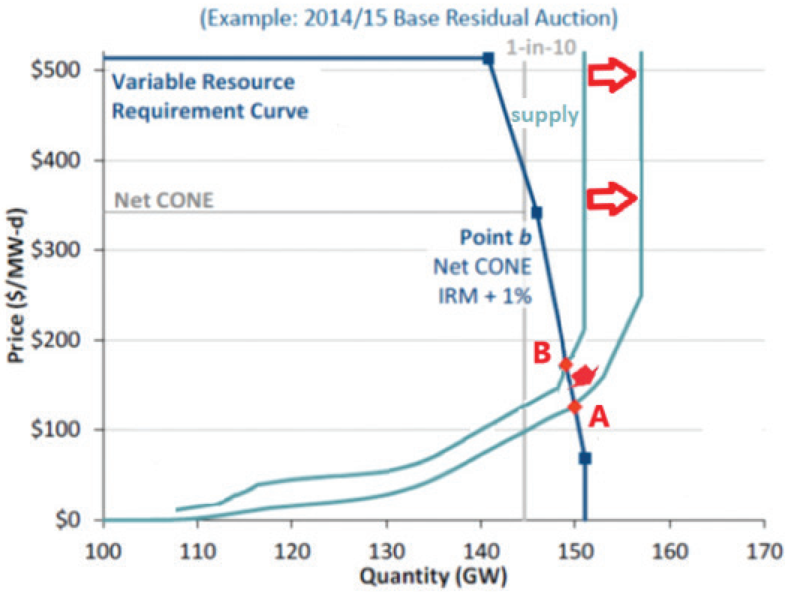
68 *See Coal Incentive Tax Credit*, KY. Dep't of Revenue, https://revenue.ky.gov/Business/Pages/Coal-Incentive-Credit.aspx (last visited Apr. 24, 2018).

69 PJM, Database, *Subsidies to Participants in PJM States, Based on Good Jobs First Subsidy Database*, https://earthtrack.net/sites/default/files/uploaded_files/20170605-item-02-subsidy-short-list-20170531.xls (last downloaded Apr. 24, 2018); *see also* Doug Dkoplow, *Subsidies to Suppliers in the PJM Interconnection Go to Fossil and Nuclear, Not Just Renewables*, EarthTrack (Jul. 20, 2017), https://earthtrack.net/blog/subsidies-suppliers-pjm-interconnection-go-fossil-and-nuclear-not-just-renewables (discussing these subsidies).

70 For example, Oil Change International reports that United States federal and state governments gave away $20.5 billion a year on average in 2015 and 2016 in production subsidies to the oil, gas, and coal industries, including $14.7 billion in federal subsidies and $5.8 billion through state-level incentives. Janet Redman, Oil Change Intl., Dirty Energy Dominance: Dependent on Denial 5 (2017), http://priceofoil.org/content/uploads/2017/10/OCI_US-Fossil-Fuel-Subs-2015-16_Final_Oct2017.pdf.

existing clean resources that were previously unable to clear the market lowered their bids, or if new clean resources entered the market.

Figure 3: Capacity Supply and Demand in RPM



Source: Samuel A. Newell Pfeifenberger et al., *Third Triennial Review of PJM's Variable Resource Requirement Curve*, The Brattle Group (May 15, 2014), https://www.pjm.com/-/media/committees-groups/task-forces/cstf/20140630/20140630-item-04c-vrr-curve-background.ashx.

But, by design, the capacity market would react to those changes. A capacity market serves as a means of recovering fixed investment costs for many generators.[71] While lowered capacity prices will tend not to push the existing clearing generators out of the market,[72] they may discourage the entry of certain types of resources: namely, those resources for which the lower capacity price level, combined with expected profits from energy markets, would be insufficient to cover the investment costs. In the long term, such discouragement would change the supply curve, shifting it back to the left and thereby increasing capacity prices. Therefore, any decrease in price can continue only as long as there is a glut in capacity. Short-term shortage or surplus conditions, and resulting price changes, are only a natural result of market dynamics, and do not warrant market design changes.

With a properly constructed capacity demand curve, the capacity price automatically adjusts to reflect the costs of the new generators that are necessary for resource adequacy when supply becomes scarce.[73] Further, because the Variable Resource Requirement curve is updated every three years based on energy market revenues, it will shift up if energy market revenues go down, increasing the price PJM is willing to pay for any given level of capacity. In other words, capacity markets, by design, ensure that enough capacity is present to meet the highest demand in a given period. As a result, even if externality payments reduce capacity prices in the short term, capacity markets are designed to adjust to that change and keep prices at a level necessary to ensure resource adequacy.

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71 Some of the resource might be able to fully recoup the investment costs through profits made at energy market.

72 For existing clean generators, the investment costs are already sunk and even if the change in market conditions renders the full recovery of the initial capital costs impossible, staying in the market is still more profitable for them than shutting down if they can cover their variable costs, including their yearly maintenance costs, in the energy market.

73 A separate question is how firms form expectations about the future capacity prices. If they expect the prices to fluctuate as described in the above paragraph, the initial discouragement effect will be much weaker.

Current capacity market designs exhibit flaws unrelated to externality payments that must be addressed

While externality payments do not threaten the capacity markets, there are other flaws in current markets that must be studied and addressed. In fact, as the U.S. Government Accountability Office recently concluded, the performance of capacity markets has not been well studied.[74] While FERC has conducted assessments of individual aspects of the market design, it has never fully assessed "how well the capacity markets have performed individually or overall relative to their objective of ensuring adequate resources at just and reasonable prices."[75] At the same time, "stakeholders continue to raise questions about the performance of capacity markets."[76] Nonetheless, it is clear that there are three categories of problems present in capacity markets today—all of which cause problems in capacity markets that are unrelated to externality payments. Yet, none are addressed by the reforms.

First, there is a capacity glut in many regions. For example, PJM's capacity auctions have led to commitments well above the required target reserve margin of 16.6%. For delivery year 2020/2021, though, a record-high reserve margin of 23.9% cleared the RPM Base Residual Auction.[77] That result represents a surplus-above-target margin of about 11,000 megawatts, which amounts to maintaining an extra 22 coal or gas plants (at 500 megawatts each) or 11 nuclear plants (at 1,000 megawatts each).[78] The ISO-New England annual capacity auction completed in February 2017 closed with the lowest prices since 2013 and ample reserves. ISO-New England has acknowledged this significant excess capacity.[79] Moreover, in both markets, many generators that do not clear the capacity auction still participate in the energy market.

Those numbers suggest that the amount of capacity operating in the market is inefficiently high. The capacity market needs time to adjust to design changes and many frequent changes create unclear signals. Therefore, in PJM, frequent changes in the design of the capacity market might have contributed to the oversupply. It is also possible that the design of the market, such as the lack of seasonality or an unnecessarily high Variable Resource Requirement Curve, exhibits deficiencies that cause the inefficiently high amount of capacity to be present. In any case, given this glut, price signals in the near future should either encourage exit of inefficient generators, rather than discourage it, or discourage entry of inefficient generators. Given this evidence, it is not clear why the potential price suppression effects of externality payments, if indeed present, is a cause for concern.

Second, the use of a Minimum Offer Price Rule (MOPR) in many regions is problematic. This rule imposes a minimum offer price for a new resource when the decisionmakers suspect that the resource would submit an "uncompetitive" low bid and thus artificially lower capacity auction clearing prices. MOPRs were initially designed to prevent the exercise of buyer-side market power. However, it is currently used widely and without any regard for market power issues. The

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74 *See* U.S. Gov't Accountability Office, Gao-18-131, Electricity Markets: Four Regions Use Capacity Markets To Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their Performance (2017), https://www.gao.gov/assets/690/688811.pdf.

75 *Id.* at 49.

76 *Id.* at 49.

77 PJM 2020/2021 RPM Base Residual Auction Results, *supra* note 64.

78 Jennifer Chen, *Got Clean Energy? Not So Much from PJM's Latest Auction*, Nat. Res. Def. Council (May 23, 2017), https://www.nrdc.org/experts/jennifer-chen/got-clean-energy-not-much-pjms-latest-auction.

79 The grid operator needed to procure about 34,000 MW and wound up with more than 35,800 MW. *ISO New-England*, 162 FERC ¶ 61,205, P 38 (2018).

premise of a MOPR "appears to be based on an idealized vision of markets, free from the influence of public policies."[80] But as former FERC Chairman Norman Bay explained, markets are indeed affected by many different public policies.[81] Therefore, it is irrational to take action to address externality payments without also considering other subsidies. More recently, FERC Commissioner Richard Glick similarly criticized the application of MOPRs to resources receiving externality payments as "ill-conceived, misguided, and a serious threat to consumers, the environment and, in fact, the long-term viability of the Commission's capacity market construct."[82]

Additionally, a MOPR adjusts the bids deemed uncompetitive to the level determined by the levelized cost of construction net of a historical average of annual net revenue from sales of energy and ancillary services (Net CONE). However, the levelized Net CONE is not the economically rational capacity bid for a generator.[83] For a resource that is committed to being in operation in the given delivery year, for instance because it is already under construction, it would be optimal to submit its net going-forward cost or its opportunity cost, implying that the bid would be at a level lower than Net CONE. Thus, MOPRs fail in their attempts to create "competitive" bids by forcing the resource to submit a bid a higher than it would have bid even in the absence of externality payments, and penalizes the resources subject to a MOPR while inefficiently inflating the capacity clearing prices.

Particularly in ISO-NE, the MOPR prohibits some resources from clearing the market even though those resources will continue to stay in the market because of the externality payments they get from the states. Consequently, the capacity market may be sending signals about the relative scarcity of capacity, leading to new installations, despite enough generation being available on the market. MOPRs can therefore be seen as one of the main drivers of the overcapacity.

Third, the current designs do not address variations in seasonal peak loads. For example, PJM's extreme weather forecasts for the 2021-2022 season suggest that summer peak loads will exceed winter peak loads by over 25,000 MW.[84] Thus, capacity requirements needed to maintain resource adequacy are considerably larger in the summer than in the winter. However, the fact that PJM adopted a Capacity Performance requirement of year-round availability in its 2017 RPM auction implies that the market does not send the proper signal about when the additional capacity is needed. Combined with the seasonal character of some resources,[85] lack of seasonality creates an inefficiency—the market sends signals for investment in year-round capacity even though the existing year-round capacity combined with seasonal resources might be able to meet the demand at all times during the year.

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[80] *See* Modern Markets Intelligence, Inc., *Bay Picks Apart MOPR Concept on Last Day at FERC*, PowerMarketsToday (Feb. 7, 2017), https://www.powermarketstoday.com/public/Bay-picks-apart-MOPR-concept-on-last-day-at-FERC.cfm.

[81] *Id.*

[82] *See* Comm'r. Richard Glick, *Dissenting Comments about The ISO-NE Competitive Auctions with Sponsored Policy Resources Proposal Docket No. ER18-619-000*, FERC (Mar. 9, 2018) [hereinafter "Glick Dissenting Comments"], https://www.ferc.gov/media/statements-speeches/glick/2018/03-09-18-glick.asp#.Wr1p0q2ZPUo.

[83] *See* Wilson, *supra* note 24, at 29-32; *Post Technical Conference Comments of James F. Wilson, Docket No. AD17-11-000*, FERC (June 22, 2017), https://www.ferc.gov/CalendarFiles/20130911145022-Wilson%20Comments.pdf.

[84] Organization of PJM States, Inc., OPSI Resolution #2017-01, Demand Side Resource Participation in PJM Markets (2017), http://www.pjm.com/-/media/about-pjm/who-we-are/public-disclosures/20171010-opsi-letter-and-resolution-regarding-demand-side-resoruce-participation-in-pjm-markets.ashx?la=en.

[85] For example, the solar generation stronger in the summer than in the winter and thus has difficulty fulfilling the Capacity Performance year-round requirements.

Economic theory gives a clear reasoning for this inefficiency.[86] Economics prescribes that policymakers need to have at least as many policy tools available as they have targets.[87] As economic literature demonstrates, in capacity markets with at least two different seasonal maximum demand levels, which is tantamount to various capacity "targets," having just two instruments – a capacity price and energy price cap, cannot lead to efficient outcomes. Market designers should think of introducing other dimensions into their designs, such as capacity markets with targets that vary with location and season.

Additionally, as capacity price signals are less granular with respect to location and time relative to energy market price signals, decreasing energy prices means that resources like energy storage, demand response, and variable renewables would not receive any additional compensation for the additional benefit they provide in being able to provide energy in certain places and times.[88]

Understanding and addressing these flaws is imperative to the functioning of the capacity markets. Before moving forward with any more design changes that can potentially harm economic efficiency, it is important to recognize the root cause of any observed outcomes, and to address those causes directly.

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86 *See* Paul Joskow & Jean Tirole, *Reliability and Competitive Electricity Markets*, 38 RAND J. Econ. 60, 60–84 (2006).

87 *Id.* at 75; *accord* Jan Tinbergen, On the Theory of Economic Policy (2d ed. 1952).

88 Chen, *supra* note 6.

Current Capacity Market Reforms

Reforms currently underway in ISO-NE and PJM do not solve the underlying problems in wholesale markets. Further, they might even fail to achieve the stated goal of these reforms—inducing efficient entry—while creating other distortions to economic efficiency.

First, externality payments for resources are based on their energy generation, rather than on their capacity. As such, any potential inefficiency associated with these payments, if they exist, would be directly connected to the energy market. Reforms suggested in PJM and ISO-NE, however, are aimed at reforming only the capacity market, without addressing the key underlying issues that prompted the externality payments in the first place—the fact that current energy markets fail to achieve economically efficient outcomes due to the presence of externalities. And a policy that counteracts the impact of the externality payments would just reverse the attempts to internalize those external costs.

A more desirable approach to reforming wholesale markets to address externalities is being taken by New York ISO (NYISO). NYISO is currently considering the introduction of a charge for CO_2 emissions in the energy market.[89] Such a charge would automatically level the playing field among various generators depending on their emissions intensity, without the need for resource-specific attribute payments.[90] NYISO's approach therefore directly targets the source of the inefficiency in the energy markets—the externality—and it is therefore a superior approach to any of these capacity market reforms.

Second, the reforms may not achieve the intended goal of incentivizing efficient entry. Reforms try to achieve the goal of keeping capacity prices elevated in the presence of externality payments. Higher capacity prices will, if all other things are held constant, reduce the incentives for existing generators to leave the market and increase the incentives for entry. Thus, the increase in capacity prices will increase the supply of available capacity. However, it is not currently clear whether the increase in capacity will be achieved by slower exit of existing generators, faster entry of new resources, or a combination of both. Thus, it is not even clear that attempts to modify capacity markets in order to keep capacity prices high, in response to the introduction of externality payments, would lead to more entry as desired by the ISOs/RTOs.

Without knowing which type of resource is the most responsive to capacity prices, it is hard to know the relative magnitudes of the changes in entry and exit behavior. If, for example, older and higher emitting resources are most price responsive, and if these types of generators usually set the price in capacity markets, then an increase in the prevailing capacity prices would lead them to stay in the market longer. As a result, the existence of this additional capacity that would not have stayed in the market otherwise, would lower the clearing price in the capacity market, partially counteracting the goal of the market redesign proposal. In addition, if these resources stay in the market longer than they otherwise would have now that the capacity prices are higher, they increase the available supply for the energy market, leading to a decrease in the energy prices. Because many resources rely mainly on energy market revenues, such potential for reduced revenue

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89 For additional information on planned carbon pricing in New York see N.Y. Indep. Sys. Operator, Pricing Carbon into NYISO's Wholesale Energy Market to Support New York's Decarbonization Goals (2017), http://www.nyiso.com/public/webdocs/markets_operations/documents/Studies_and_Reports/Studies/Market_Studies/Pricing_Carbon_into_NYISOs_Wholesale_Energy_Market.pdf

90 With a carbon charge the generators still do not have incentives to internalize the external costs associated with local pollutants such as SO_2 or NOx.

might lead to a decrease in the entry rates, which would contradict the goals of market operators. Importantly, because the clean resources rely on the energy revenue more heavily than on capacity payments, a redesign not only might fail to attract entry, but could also additionally undermine states' efforts in addressing externalities.

Whether the higher entry rates or slower exit rates would be the main driver of the capacity increases depends on the characteristics of the market participants, in particular their costs of going forward, marginal costs of energy generation, and investment costs for the potential entrants. A simple scenario analysis with added resources that get externality payments would not be sufficient to understand the implication of externality payments on market outcomes, or on entry and exit incentives. A sophisticated modelling of the interconnected capacity and electricity markets, including the explicit consideration of formation of expectations concerning future periods, would be needed to determine the effect of the reform proposals and whether they would indeed lead to increased entry. Such modeling necessary to inform decisionmaking has not been done.

Third, each of the reforms would create additional distortions and harm economic efficiencies in different ways, depending on the specifics of the designs. Below, we review the reforms that are being discussed, and explain economic inefficiencies caused by each of the three reforms.

PJM's capacity repricing proposal

PJM is considering two proposals: a two-stage capacity repricing proposal and an Extended Minimum Offer Price Rule (MOPR-Ex).[91] The capacity repricing proposal introduces a two-stage auction. The first stage of the auction determines which resources clear the capacity auction based on the initial bids submitted by each resource.[92] The second stage, in which the initial bids of the resources are substituted with PJM-determined "competitive" bids, determines the price to be paid to all the resources cleared in the first stage.[93] PJM argues that the two-stage capacity pricing proposal scheme would raise the capacity prices to a level reflecting the bids that would have been offered without externality payments and hence would administratively adjust subsidized resource offers to prevent capacity price distortions.[94]

There are several reasons why PJM's two-stage capacity repricing proposal would hurt economic efficiency. First, adding a second stage to the current auction design will change generators' bidding behavior for the first stage auction. As we explained in Section I, the current auction design contributes to economic efficiency by giving generators the incentives to bid their true costs of staying in or entering the market. However, when a second-stage, in which the price is adjusted upwards, is added to the current design, the first-stage incentives of the generators change. Knowing that the final price will be adjusted upwards, generators might offer their capacity at prices below what would have been their "truthful" bid. While such bidding behavior does not necessarily lead to inefficiency under every circumstance, the equilibrium outcome of the bidding can no longer be guaranteed to be efficient.[95]

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91 PJM filing, *supra* note 4.

92 PJM filing, *supra* note 4, at 51.

93 PJM filing, *supra* note 4, at 51.

94 PJM, *Capacity Market Repricing Proposal*, (June 29, 2017), http://www.pjm.com/-/media/committees-groups/task-forces/ccppstf/20171016/20171016-pjm-executive-summary.ashx

95 Inefficiency may happen when generators have differing beliefs about each other's bids. In such a case their submitted bids may lead to more expensive generators clearing the market while the cheaper ones lose the auction. It is also possible with the shading that the adjusted price will not cover the true costs of generators. *See* Paul Milgrom, *Auctions and Bidding: A Primer*, 3 J. Econ. Perspect. 3 (1989) (for introductory discussion about the efficiency and information available to bidders).

Second, the price that is determined in the second stage will no longer show the willingness-to-pay for the incremental reliability benefit for a given level of available capacity in the market as determined by PJM's capacity market demand curve. Even though this demand curve is administratively designed and set, bifurcating how the prices and quantities are determined ignores the logic of the demand curve.[96] The second-stage price would reflect the willingness-to-pay for additional capacity as if the sponsored resources were offering capacity at the PJM-specified prices, often making them look prohibitively expensive. But, if the offers were indeed this high, and, hence, the supply curve truly corresponded to the supply curve PJM would use in the second-stage auction, the PJM-determined downward sloping demand curve would have led to a lower level of contracted capacity at the equilibrium than the amount that cleared the first-stage auction. This result highlights the basic logic of a downward-sloping demand curve—the actual willingness-to-pay for the additional capacity decreases with the amount of cleared capacity because the incremental reliability benefit of additional capacity, given the level of available capacity, is lower. The repricing approach completely decouples the quantity of the contracted capacity from the benefits associated with it. As a result, the bifurcation will lead to higher prices for a given level of capacity, thereby increasing the prices consumers pay, but also undermining the logic behind the design of demand curve. Any justification for the elaborately chosen shape of demand curve would be lost if such a proposal is implemented.[97]

PJM's reasoning that the proposal would "maintain the correct price signal"[98] by restoring the prices that would have resulted in a world without externality payments by adjusting only the bids of units that gets these payments is also misguided. Emitting resources might already be taking other firms' externality payments into account in their current bids. Given that clean resources are usually characterized by low marginal cost of energy generation, their presence in the market already substantially reduces the profits of emitting resources in energy markets. Because the capacity and energy markets are strongly interrelated, emitting generators' capacity bids should already reflect the profits lost on the energy market and be higher compared to a scenario without externality payments. Therefore, a counterfactual analysis that adjusts only the bids of the resources that get externality payments, and not others, would not correctly simulate what would have happened without these payments. PJM's "correct price signal" is bound to be higher than the counterfactual price that would have been reached in a hypothetical market without any state policies.

The effect of capacity repricing on PJM's emissions would depend on how various types of resources respond to increases in capacity prices. Under the likely scenario that inflated capacity prices prolong the economic life of emitting resources while having no (or low) impact on the entry of clean resources, total emissions would rise. On the other hand, should the higher capacity price attract new zero-emission resources, the redesign of the market would decrease emissions.

[96] Levelized net cost of new entry (Net CONE) serves as a reference point for constructing the capacity demand curve. It is the estimated nominal levelized fixed costs of entry based on a 20 year asset life of a combustion turbine net of estimated energy and ancillary service margins. PJM states that: "In designing the VRR Curve, PJM seeks to ensure that the amount of capacity it procures satisfies a loss of load expectation of one event in 10 years. The price axis of the VRR Curve contains multiples of the Net CONE value, and the megawatt quantity axis contains the target reliability requirement. Higher prices (above Net CONE) are associated with capacity shortage conditions and lower prices are associated with excess capacity conditions", Order on Rehearing and Compliance, *PJM Interconnection, L.L.C.*, 153 FERC ¶ 61,035, P 1 (2015), https://www.ferc.gov/whats-new/comm-meet/2015/101515/E-23.pdf.

[97] *See* for example Triennial Review of VRR Curve Shape (June 2014) *available at* https://www.pjm.com/-/media/committees-groups/task-forces/cstf/20140630/20140630-item-04c-vrr-curve-background.ashx

[98] PJM Filing, *supra* note 4, at 1.

PJM's Extended Minimum Offer Price Rule

The Extended Minimum Offer Price Rule (MOPR-Ex), on the other hand, would extend the existing MOPR by applying it to all existing and new resources that will receive revenue outside of the market, regardless of the resource types, while providing a narrowly-defined renewable portfolio standard exemption.[99] PJM's Independent Market Monitor, which originally suggested the MOPR-Ex, argues that the MOPR-Ex would "preserv[e] the efficient market outcomes and accurate signals for entry and exit that are necessary for well-functioning and competitive markets."[100]

However, the MOPR-Ex would cause all the standard problems that have been raised related to any MOPR. In particular, it will cause excess capacity because it disregards some of the already existing capacity in the market. And, it leads to consumers paying twice for available capacity through (1) higher prices in the capacity markets and (2) externality payments through state programs.[101]

The MOPR-Ex will prevent some of the clean resources from clearing the market because they receive revenue outside the market, while strengthening the incentives for entry by sustained high prices. If some of the resources that are subject to the MOPR-Ex decide to stay in the wholesale markets even after failing to clear the capacity market, there will be excess capacity, reducing the prices in the energy market.[102] As lower energy prices will lead to lower energy revenues for all resources, all existing resources, even those that are not subject to the MOPR-EX, will need to bid higher in capacity markets to recover their net expected costs of going forward. The "counterfactual" prices—capacity prices that would have been reached in the absence of state policies—will thus not be restored.

In addition, with the MOPR-Ex, total capacity costs will be inefficiently high. Consumers will have to pay for operation and maintenance costs of the excess capacity as well as additional investment costs of the new units that are not really required to ensure the system's reliability.

If the MOPR-Ex leads to some zero-emission resources exiting, or not entering the market in the first place, it also will counteract the goals of state policies or make it costlier for states to achieve their goals. Because resources subject to the MOPR-Ex cannot get capacity market revenues, they will have to rely on energy market revenues and externality payments. If, for whatever reason, energy market revenues fall, states may have to increase externality payments to achieve their environmental goals. Such an increase in externality payments would not only make it inefficiently costly for states to achieve their goals, but would increase the amount "out-of-market" revenues that parties were so concerned about at the beginning of the process. Thus, a MOPR should be used only for the narrow circumstances for which it was originally intended—preventing the exercise of buyer-side market power—but not for "accommodating" or "mitigating" state environmental and public health policies.[103]

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[99] PJM filing, *supra* note 4.

[100] *Id*, at 1.

[101] *See* ISO New England Inc., ER18-619-000, Revisions to ISO-NE Tariff Related to Competitive Auctions with Sponsored Policy Resources 3 (January 8, 2018), https://www.iso-ne.com/static-assets/documents/2018/01/er18-619-000_caspr_filing.pdf.

[102] In particular, the prices during the (super-)peak time will be squeezed. *See* the discussion in section X on the interdependence between outcomes on capacity and energy markets.

[103] Though the minimum offer price rule began as a reasonable effort to combat "true attempts to exercise buyer-side market power," recently, it has "morph[ed]" into "an examination of whether states have provided support or a subsidy to a resource that is selling into the capacity market." Order on Rehearing, *ISO New England Inc.*, 158 FERC ¶ 61,138, 892 (2017) (Bay, C., concurring); *see* Glick Dissenting Comments, *supra* note 82.

Zero-emission resources that receive externality payments but do not qualify for the narrowly defined renewable portfolio standard exemption will potentially not receive any capacity revenue, and will thus be harmed. Additionally, with a MOPR leading to overbuilding of capacity, the energy revenue of zero-emission resources will, all other things held constant, fall as well. Therefore, units subject to a MOPR will see their relative competitiveness and profitability decrease, leading to a slower entry of clean resources and a slower rate of emission reductions. But, it is not clear how the redesign will impact the zero-emission resources exempted from a MOPR. The effect and thus the change in emissions will depend on their responsiveness to the price changes relative to the price responsiveness of polluting resources.

ISO-NE's Competitive Auctions with Sponsored Policy Resources

ISO-NE also proposed a change, which FERC recently approved.[104] That proposal, known as Competitive Auctions with Sponsored Policy Resources (CASPR), allows new generators that receive externality payments (or "sponsored policy resources" as defined by ISO-NE) to enter the capacity market when those generators replace the older existing capacity resources that are willing to exit. To coordinate the entry of new resources and the exit of existing resources, CASPR introduces a new substitution auction that runs immediately after the regular capacity auction. The substitution auction settles at a clearing price differently than the regular capacity auction, based on the new supply capacity of "sponsored policy resources" and the capacity of existing resources that are willing to exit. This price is then paid to the new resources by retiring resources to take over the obligations assigned in the initial auction. Therefore, the retiring resources receive revenues based on the difference between the higher price in the primary auction and the lower price in the substitution auction as a "severance" payment to leave the market.[105] The new sponsored policy resources receive the lower price in the substitution auction, while new resources that are not state-sponsored receive the higher price in the primary auction. [106]

Prior to CASPR, ISO-NE applied a MOPR to new capacity resources and required the "sponsored assets" to bid at their unsubsidized cost.[107] Its rules allowed for a limited exemption for certain types of renewables to address states policies. Given that the application of a MOPR is in itself problematic, modifying rules to allow for more participation from resources that get externality payments was desirable. CASPR, however, only partially achieves that goal at the cost of bringing new distortions to the market.

With CASPR, new resources that receive externality payments will still be subject to a MOPR in the primary auction. However, they will be allowed to participate in the substitution auction without a MOPR if they could otherwise not clear the primary auction. Thus, these new resources will be able to receive capacity payments only if they can clear the substitution auction, which is intended to coordinate the entry of new policy resources with the exit of existing resources that are willing to "buy out" their obligation and retire.[108] As a result, this setup implies that the rate of entry from resources that receive externality payments will hinge on the willingness of existing plants to exit, without regard for states' preferences. Furthermore, CASPR considers a clean resource to be "new" as long as it does not clear the substitution auction. This means that, in an extreme case where no existing resource is willing to exit the market, ISO-NE would treat that resources as "new" throughout its entire physical life, always subjecting it to a MOPR.

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[104] *See* Order on Tariff Filing, *ISO New England Inc.*, 162 FERC ¶ 61,205, P 4 (2018).

[105] *See Competitive Auctions with Sponsored Policy Resources (CASPR) Key Project*, ISO New England, Inc., https://www.iso-ne.com/committees/key-projects/caspr/ (last visited Mar. 29, 2018).

[106] The sponsored policy resources can also bid into the primary auction but they would be subject to MOPR, and thus less likely to clear.

[107] ISO New England, Inc., *supra* note 105, at 2.

[108] The Renewable Technology Resources exemption will be phased out within the next 3 years.

In addition, the proposal will lead to distorted incentives, both for existing resources close to retiring and for new resources that do not get externality payments. The existing generators that may be willing to retire will have incentives to distort their bids in the primary auction. Without the substitution auction, the generator would have earned the difference between the primary auction price and its net cost of going forward. The substitution auction, however, creates a new revenue potential. If an existing resource clears the substitution auction and exits the market by transferring its obligations to a new resource, it would earn the difference between the primary auction price and the substitution auction price. Therefore, if the price in the substitution auction is lower than the cost of going forward for a resource, that resource would be better off if it clears the primary auction, participates in the substitution auction and transfers its obligations to a new resource. The possibility of higher earnings through the substitution auction will create incentives for resources to lower their primary auction bids enough, even below their costs of going forward, to ensure that they clear. As a result, if resources expect that the substitution auction price will be lower than their own cost of going forward, they will submit low bids in the primary auction. Again, because resources are no longer incentivized to bid their marginal costs, the efficiency of the primary auction results can no longer be guaranteed.

Further, the final mix of resources in the market may not even be the cost-minimizing capacity mix. By design, the first stage considers the generators receiving externality payments only at price levels above the MOPR. However, capacity clearing prices are usually far below MOPR floor prices. Consequently, when the bids of some resources are mitigated, the prices may indicate capacity scarcity, sending signals for entry, despite enough capacity being present in the market to guarantee resource adequacy. New emitting resources may clear the primary market as long as they bid lower than the MOPR, leading to inefficiently high costs.[109] Therefore, CASPR might lead some of the existing capacity to retire based on the revenue from the substitution auction, even if that capacity would have been considered economic in the previous setting based on going-forward costs. It would do so while allowing new resources that have higher costs, and hence would not have been economic in the previous setting, to enter and clear the market.[110]

CASPR forces the new sponsored policy resources to participate in the substitution auction where, by design, the clearing prices are lower than in the primary auction. In this way, CASPR curtails the revenue of clean resources compared to emitting generators. The reduced competitiveness of the sponsored policy resources will lead to higher pollution levels than those that would occur with regular, one-stage capacity markets.

[109] For a discussion, *see* Motion to Intervene and Protest of the ISO-New England External Market Monitor, Docket No. ER18-619-000, *Revisions to ISO New England Transmission, Markets and Services Tariff Related to Competitive Auctions with Sponsored Policy Resources* (Jan. 30, 2018), https://www.potomaceconomics.com/wp-content/uploads/2018/03/EMM-Protest-FERC.pdf.

[110] *Id.*

Conclusion

Wholesale market operators have begun considering and implementing several proposals to reform capacity markets in order to counteract the feared impact of state-level externality payments. These proposals are misguided for two important reasons. First, the proposals are based on the unfounded premise that externality payments have or will cause inefficient capacity-market distortions. Externality payments help internalize externalities, and thus help improve economic efficiency. And, to the extent that externality payments have affected the market, this is the natural effect of policies that help internalize the cost of carbon pollution.

Second, there is no sound evidence that state-level externality payments cause economically inefficient distortions to capacity market prices or that they harm resource adequacy. To the contrary, capacity markets continue to be marked by over-supply. Capacity markets are designed to ensure resource adequacy, and will adjust according to changing conditions in the market. Reforms that aim to counteract externality payments will bring new distortions to the market at the cost of states' ability to combat climate change.

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