CEEPR

MIT Center for Energy and Environmental Policy Research

Newsletter

SPRING 2022

MASSACHUSETTS INSTITUTE OF TECHNOLOGY

Editorial.

As the last MIT CEEPR newsletter went into press in late 2021, our editorial cautioned that geopolitical tensions could "continue to spill over into energy markets, creating regional uncertainty about the availability of energy." At the time, we could hardly have anticipated the disruptive effect of Russia's invasion of Ukraine only a few months later on energy markets around the world. Confronted with the largest military conflict on the continent since the Second World War, European nations – highly dependent on Russian hydrocarbon exports – have raced to diversify supplies and improve energy security. Doing so will take time, however, and likely exacerbate – at least in the short term – a surge in energy costs caused by rebounding demand and a global supply shortfall as the world recovers from the global COVID-19 pandemic.

Against initial expectations, the evolving geopolitical landscape and newly ascendant policy priorities have not yet led to widespread reconsideration of national and regional energy transition roadmaps. If anything, some jurisdictions have announced their intention to accelerate renewable energy deployment timelines as a means to promote energy security and independence. That, in turn, heightens the urgency of persistent questions about a suitable electricity market design for power systems with rapidly growing shares of variable renewable energy resources. While we are only beginning to understand how the unfolding crisis in Ukraine will affect energy markets more broadly, research on electricity market design is already a prominent focus of MIT CEEPR's ongoing work portfolio.

In this issue of our newsletter, we are featuring several MIT CEEPR Working Papers released in recent months that offer answers to the foregoing question. From lessons learned with market deregulation and its impact on power prices to properties of deeply decarbonized electric power systems with storage and impacts of large scale investment in wind power generation on wholesale electricity markets, this research offers valuable insights into the most pressing challenges currently faced in electricity markets in North America, Europe and elsewhere. Beyond offering diagnosis and improved understanding, it also identifies alternative solutions, from a proposed response to spiraling electricity costs in the European Union to concrete recommendations for institutional and policy reform in the U.S. electricity sector.

How policy and technology trends affect electricity markets has been a traditional mainstay of MIT CEEPR's theoretical and empirical research, and will remain so going forward. As this newsletter attests, however, the interests of affiliated faculty and staff range much more widely in the shifting domain of energy and environmental policy research. Addressing emissions leakage and industrial relocation, identifying the right technologies for decarbonization, and understanding collusion strategies against environmental regulation are but a small selection from the current research portfolio. Along with the latest Working Papers, this newsletter also lists recent and upcoming events, where much of this research has or will be presented and discussed. As we return to in-person convening after a two-year hiatus prompted by the pandemic, we look forward to sharing insights and learning from you at future MIT CEEPR events. We hope to see you soon.

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MIT CEEPR Newsletter is published twice yearly by the MIT Center for Energy and Environmental Policy Research.

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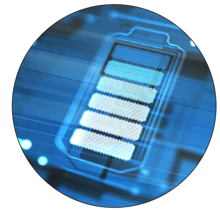


Research.

Global Externalities, Local Policies, and Firm Selection.

By: Lassi Ahlvik and Matti Liski

How to fight global problems without hurting the local welfare? Economists are increasingly confronting this question: Whether it relates to financial sector regulation, virus outbreaks, labor market standards, or cross-border pollutants, policy makers are often left with only local tools for dealing with global spill-overs. Local policies are commonly opposed on the grounds that policies force businesses out to non-regulated regimes, thereby undermining their effectiveness. For example, what is the benefit of a stricter capital requirement on a bank if, after its cross-border relocation, the systemic risk remains the same?

Lassi Ahlvik and Matti Liski (2021), "Global Externalities, Local Policies, and Firm Selection", CEEPR WP-2021-019, MIT, December 2021.

Environmental regulation is a particularly prominent case. The U.S. Congress passed a resolution opposing a carbon tax on the basis that, among other things, it "will lead to more jobs and businesses moving overseas" (H. Con. Res. 119 , 2018). In the European Union, industries have argued that, in the absence of a global climate policy, strengthening the Emissions Trading Scheme would force businesses to leave "without any environmental need" (Fagan-Watson, B., 2015). In response to such concerns, policies routinely compromise on the externality price: Rebates of environmental taxes are used to subsidize energy-intensive industries, emissions trading regimes allow the use of cheaper offsets for selected firms or industries, and a threat of relocation is used as a reason to exclude entire sectors from regulations.

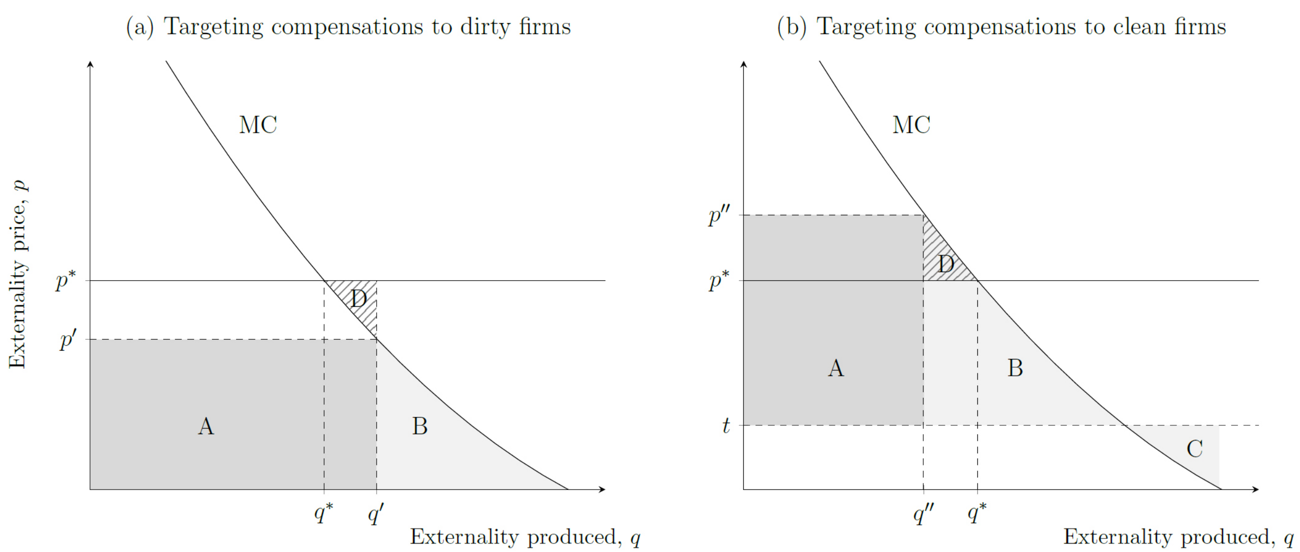
This research shows that such common policy responses to industry relocation are misguided if the policy maker is armed not only with the powers to set prices on carbon but can also allocate transfers, e.g., in the form of revenues from pollution auctions. For global problems, some firms can do more at home than others and are thus more valuable to keep: Transfers from scarce public funds should reach those firms first. But because firms' available options are privately known, the policies must incentivize firms to self-select the desired action and location. This selection effect calls for higher externality prices, not lower.

Figure 1 illustrates this idea. The marginal cost (MC) curve captures the cost of reducing the externality by aggregating unit costs over small individual firms or plants; it increases to the left starting from the unconstrained externality level. Consider externality price p* deemed optimal in the absence of firm relocation. High-cost firms pay this price and remain dirty, while firms with costs lower than p* eliminate the externality. When all firms have some risk of moving, choosing externality price p' < p*, as shown in Figure 1a, lowers the compliance cost of dirty firms (area A) and incentivizes them to stay, while creating a deadweight loss (area D). Yet, the location of these dirty firms is irrelevant for the global problem as they produce the externality regardless of their location. Therefore, the rollback of the externality price, as in Figure 1a, can never be justified by the global externality problem alone. In contrast, the problem calls for targeting compensations to low-cost firms that can limit the externality at home, as in Figure 1b: Choosing a higher externality price p" > p* accompanied by lump-sum compensation t = p"– p* would reduce the cost to the clean firms (area B) and even make regulation profitable for some firms (area C), without affecting the cost for the inframarginal dirty firms (area A).

We provide an illustrative quantification of the optimal carbon leakage policy for the key sectors in the EU emissions trading system (EU ETS) based on the firm-level data on relocation propensities from Martin et al (2014). The data allow us to draw representative relocation risk distributions for five sectors forming together 62% of the industry emissions covered by the trading program. With representative values for the social cost of carbon emissions and public funds, we quantify the optimal policies with results on carbon leakage, distortions in the emissions price, and the fraction of the sectoral cost that is optimally covered from public funds. The main theoretical results turn out to be also economically significant. The optimal local carbon prices are increased upwards by 17-29% compared to the benchmark without firm relocation.

The higher carbon prices also translate into larger cuts, even after the leakage of emissions (2-17% per sector) is taken into account: The threat of relocation, in itself, calls for 9.6 MtCO_2 additional emission reductions (13% higher than in the benchmark, an amount roughly equal to total manufacturing emissions in Sweden), and the optimal global mechanism supplements this by reducing additional 1.2 MtCO_2 abroad (2% compared to the benchmark). Finally, in this quantification, the outcome is more or less unaffected if we restrict attention to policies that set a uniform externality price for all sectors but keep the transfers differentiated.

Figure 1: Illustration of the selection effect



Notes: The graph plots marginal cost (MC) for limiting the externality when the externality price is (a) decreased ($p' < p^*$), leading to a higher externality level ($q' > q^*$) or (b) increased together with compensation ($p'' > p^* = p'' - t$), leading to a lower externality level ($q'' < q^*$). Area A: compliance cost for firms that pay the externality price. Area B: compliance cost for firms that eliminate the externality. Area C: benefits to the low-cost compliant firms. Area D: deadweight loss.

Ömer Karaduman (2021), "Large Scale Wind Power Investment's Impact on Wholesale Electricity Markets", CEEPR WP-2021-020, MIT, December 2021.

Research.

Large Scale Wind Power Investment's Impact on Wholesale Electricity Markets.

By: Ömer Karaduman

Wind energy plays a critical role in reducing greenhouse gas emissions by providing carbon-free and low marginal cost energy. In 2018, a quarter of all additional power capacity in the world was wind energy, and it is expected to become one of the dominant sources of power in the next couple of decades. As wind generators produce clean electricity, it offsets some thermal generators' production. The substitution patterns of wind generation effectively determine its environmental value.

As more wind energy is deployed, it should be accompanied by the retirement of high carbon emitter thermal power plants to achieve higher decarbonization. In 2018 wind generation only accounts for 5% of world electricity consumption. Nevertheless, increasing wind generation is already affecting generators' revenue in the wholesale market by lowering the prices due to its low marginal cost. Understanding this revenue impact of renewable generation is essential for determining the path for decarbonization in the future.

In this paper, I ask what the substitution patterns for large-scale wind generation are and how they affect existing firms' revenues. To answer this question, I use Karaduman (2021)'s framework to quantify the potential effects of large-scale wind generation in the wholesale electricity market. My model uses data from an electricity market to simulate the equilibrium effects of a wind capacity expansion in electricity markets. I account for the price impact of wind generation and find a new market equilibrium in which I allow incumbent firms to respond to wind capacity increases.

To model firms' decisions, I represent the electricity market as a multi-unit uniform price auction. Each day, before the auction, firms observe a public signal containing information such as publicly available demand and renewable production forecasts. They then bid into the electricity market a day ahead of the actual production. I simulated wind generation and modeled it as a decrease in demand for a given

Production Offsets by Wind Energy

	Offset by 1 MWh Wind Power Generation				
		Additional Wind Generation Capacity			
	Marginal Analysis	100 MW		1000 MW	
		No Response	Best Response	No Response	Best Response
Gas	-0.28	-0.23	-0.21	-0.15	-0.13
Diesel	-0.002	-0.003	-0.001	-0.001	-0.001
Import	-0.74	-0.77	-0.78	-0.79	-0.81
Carbon Emissions	-1.05	-1.05	-1.05	-1.06	-1.07
Curtailment	-	-0.004		-0.06	

Note: For the additional wind generation, I use the overall wind generation capacity factor. The sample is from South Australia Electricity Market 2017. Change in production types is in MWh/MWh Wind, and change in emissions is in ton/MWh Wind. 100 MW and 1000 MW capacity roughly correspond to 5% and 50% of the peak demand, respectively.

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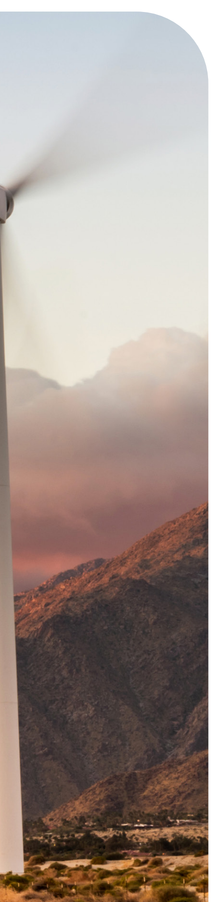
wind generation profile. I estimate incumbent firms' best responses to this shift in demand by using observed variation in demand and renewable production in a market without wind expansion. In this research, I use South Australia Electricity Market data from 2017 -2018. In the observed period, almost 35% generation comes from wind energy, one of the highest wind energy ratios among electricity markets. The current high penetration level creates a considerable variation in residual demand, which helps my model recover firms' best responses.



First, I compare offset by wind patterns with reduced form analysis for different wind expansion scenarios. I decompose offsets by the wind into two parts, merit order effect, due to price change, and market power effect, due to market power change. For small-sized wind expansion, my model give similar results to the literature on marginal impact, as market power changes are insignificant. However, as the new wind generator's capacity increases, marginal units that new wind generation offsets change, and the market power effect amplify the difference between estimates of my model and marginal approach Surprisingly, I find a similar carbon emission decrease with both models, 1.05 tons per MWh.

Next, I evaluate substitution patterns for wind generation at a much larger scale, up to 100% of the market generation capacity. South Australia trades with its neighbor region Victoria, which has a lot of brown coal generation. For a low level of wind generation investment, gas power plants with flexible technologies adjust their strategies and do not get replaced by wind generation much. Most of the renewable generation is exported to Victoria to replace brown coal. However, as the penetration level increases, the transmission between the two regions gets congested, and almost half of the renewable production gets curtailed. On the other hand, all other power plants' production in South Australia is cut almost half. In terms of emissions, large-scale wind generation cuts South Australia's carbon emissions by 60% and two times more in terms of tons in Victoria.

The impact of wind generation on different generators' revenue varies a lot at different expansion scales. For small capacity expansion, generators with flexible technologies lose the least by adjusting their bids. However, as the penetration level increases, wind generation suppresses prices, and flexible but high-cost generators stop producing. Some gas technologies lose up to 90% of their revenue. The existing wind generation gets the most considerable reduction in revenue and loses up to 91% of its revenue. These results have some policy implications. In a pathway with an aggressive wind capacity target, low carbon emitting generators may exit due to price reduction. On the other hand, as new renewable generation cannibalizes existing renewable technologies, it can be more costly to incentivize further investment in renewable technologies.

Lastly, I find that wind project production differs from each other based on their capacity factor, and this can affect the potential value of a wind generation investment. I look for potential heterogeneity between 18 existing wind projects in South Australia, and I find a significant dispersion in projects' price effects, 35%, and revenue effects, 30%. This heterogeneity leads to a policy discussion. If a policymaker has a particular concern about the capacity, price impact, or revenue impact of a project, a policy must differentiate between competing investments to ensure that the socially optimal renewable investments are made.

Research.

Why Do Firms Issue Green Bonds?

By: Julien Xavier Daubanes, Shema Frédéric Mitali and Jean-Charles Rochet

Green finance certification allows investors to link their decisions to firms' commitments toward the environment. Green bonds are the most emblematic and prominent green finance instrument: Their issuers commit to use the bond proceeds to a certified climate-friendly project. For example, Unilever announced on March 19, 2014, one of the now most famous certified green bond issues, earmarking more than $400m to new climate-friendly production capacities. This commitment confirmed the success of years-long plans to develop new green detergents and refrigerants. It was received enthusiastically by investors, generating stock returns of more than 5%. In the past few years, a rapidly increasing number of firms have made similar commitments, leading to a boom in the global green bond market (around 3.5% of total corporate bond issuance in 2020).

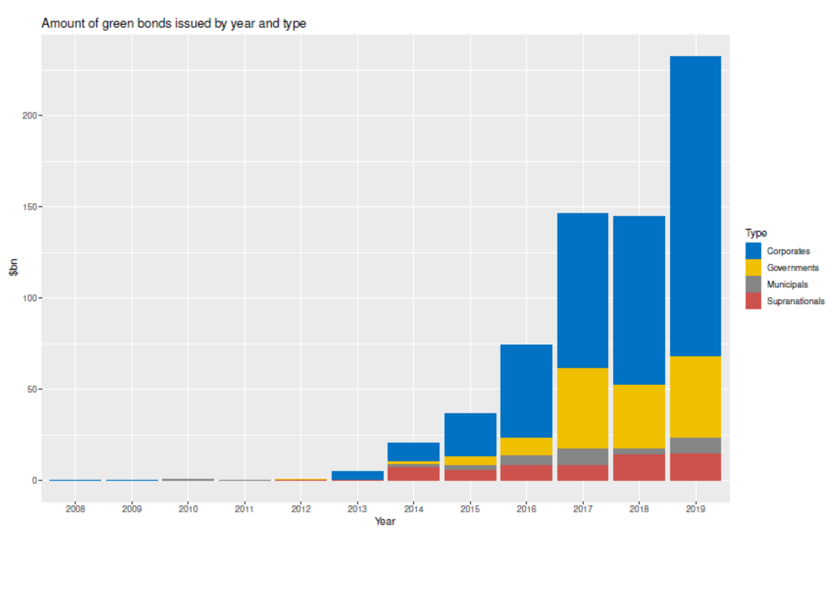
Economists have long recommended pricing carbon. In practice, however, this direct approach is less successful than hoped; even in developed countries, the effective price of most CO_2 emissions is far below the social cost of carbon. The urgency of the climate challenge calls for examining all instruments that are feasible and potentially effective.

Firms' issuance of green bonds is voluntary. Nevertheless, recent empirical evidence rules out the possibility of greenwashing (Flammer, 2021). Now more than ever, governments and financial institutions are paying a lot of attention to the rapid growth of green finance markets, hoping that it could play an effective role in climate policy. Yet economists know very little about the mechanisms that make green bonds work.

Recent empirical analyses of the green bond boom further establish the following stylized facts. First, firms' stock price increases when they announce the issue of certified green bonds and financed projects, unlike conventional bonds. Second, firms' certified green bonds do not

Figure 1. Green bonds issuance

In the past few years, a rapidly increasing number of firms have issued green bonds, leading to a boom in the global green bond market, whose volume has nearly doubled every year since 2013.



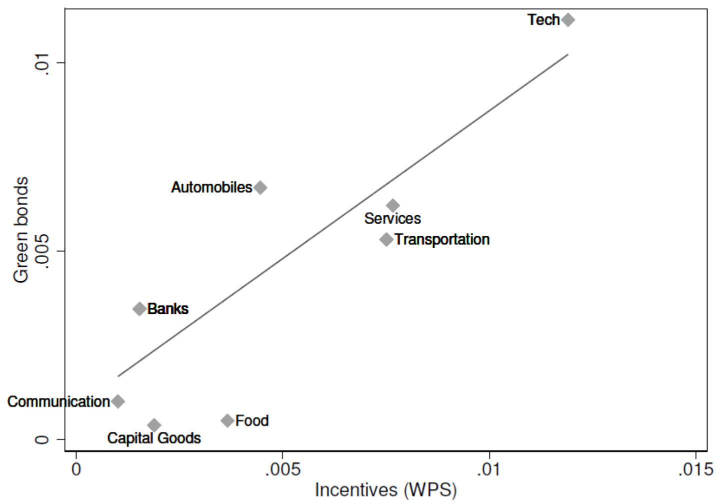


Figure 2. Green bond issuance and managerial incentives (2007-2019)

This figure shows the unconditional relationship between the proportion of green bonds and the stock-price sensitivity of managers' compensation in sectors that issue green bonds. It illustrates that sectors in which managers' pay is the most stock-price sensitive issue more green bonds.

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allow them to obtain less costly financing; green and conventional bonds pay the same to investors. Third, certification of green bonds is critical. So-called "self-labeled" green bonds are associated with neither CO_2 reduction, nor stock market reaction (e.g., Flammer, 2021).

How does one account for stock market reactions at green bond announcements? In the absence of green bond yield spread, one can reasonably rule out that concerned investors play a significant role. Positive stock market reactions, therefore, indicate that green bond certification of firms' projects conveys positive information about these projects' expected profitability.

Our theory points to the crucial role of managers' interest in the stock price of their firm. For example, managers' actual compensation schemes feature stock components. Edmans, Gabaix, and Landier (2009) measure managers' incentives as the sensitivity of their compensation to their firms' stock price, an incentive measure that is comparable across sectors and over time. Figure 2 shows, for example, the unconditional relationship between the proportion of issued green bonds and Edmans et al.'s managerial incentive measure: Sectors in which managers' pay is more stock-price sensitive issue more green bonds.

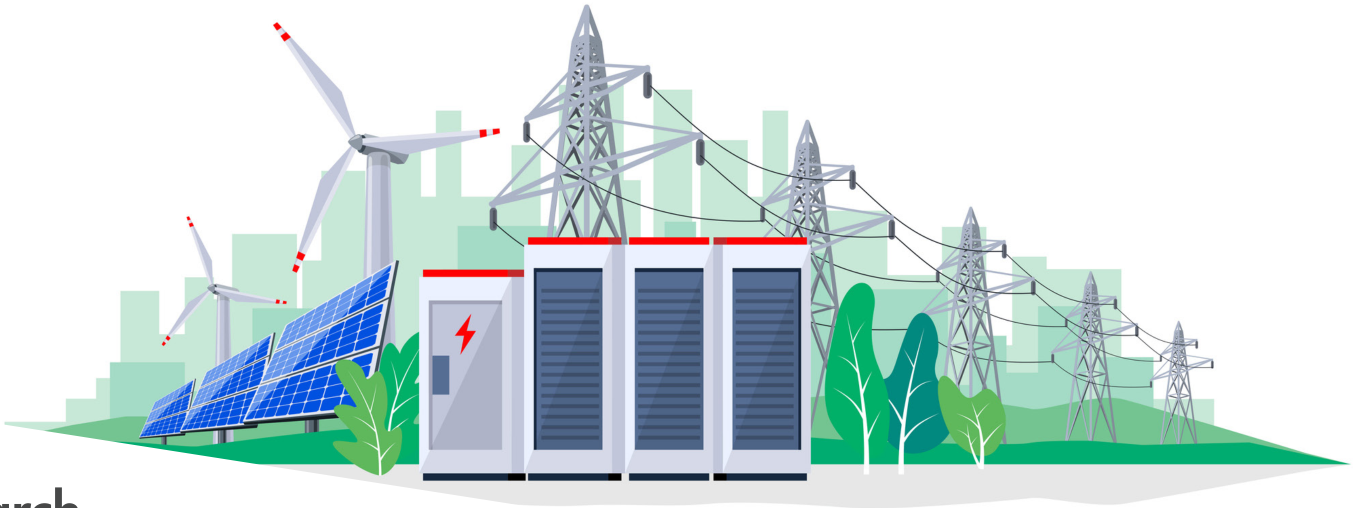
Our analysis unveils that it is existing carbon penalties that explain this relationship! Besides green bonds, effective carbon prices in most countries already provide firms with some, although insufficient, incentives to undertake CO_2 reducing projects. Our model highlights that with green bonds, the effect of carbon prices is twofold: It induces firms to undertake more certified green projects not only because carbon prices penalize conventional technologies, but also because, all else unchanged, these penalties amplify the stock market reaction to green bonds and, therefore, managers' interest in certified green projects.

We obtain a testable positive relationship between, on the one hand, the proportion of green bonds issued in an industry, and, on the other hand, the interaction between the carbon price that this industry is applied and managers' concern for their firms' stock price.

To verify this prediction, we use data that relate public firms' certified green bonds to the stock-price sensitivity of managers' compensation in their industry and to the effective carbon price that prevails where they are based. We find that the total role of managerial incentives is positive on average, and statistically different from zero as carbon prices are sufficiently high, e.g., around the average effective carbon price in the EU, where the green bond market is the most developed.

We draw the following conclusions. First, certified green bonds can induce firms to commit to effective CO_2 reductions even though green bond issuance is voluntary. Second, perhaps surprisingly, firms' incentives to issue green bonds is likely a matter of short-term financial interest. Third, green bonds are complementary to carbon pricing, with important practical implications. With green bonds, governments cannot dispense with carbon penalties; on the contrary, the latter are instrumental in the effectiveness of the former. At the same time, if carbon prices are sufficiently high, green bonds are likely to make them more effective.

Julien Xavier Daubanes, Shema Frédéric Mitali and Jean-Charles Rochet (2022), "Why Do Firms Issue Green Bonds?", CEEPR WP-2022-001, MIT, January 2022.



Research.

Properties of Deeply Decarbonized Electric Power Systems with Storage.

By: Cristian Junge, Cathy Wang, Dharik S. Mallapragada, Howard K. Gruenspecht, Hannes Pfeifenberger, Paul L. Joskow, and Richard Schmalensee

As policy makers across the world design and implement policies to achieve long-term deep decarbonization of the power sector, the share of variable renewable energy (VRE) generation (i.e., wind and solar) is expected to grow substantially in the next few decades. The large-scale integration of wind and solar generation is contingent on designing flexible power systems that can balance variations in wind and solar output to continuously meet electricity demand. In low-carbon systems dominated by VRE generation, the availability of dispatchable resources (e.g., natural gas, nuclear, coal, and reservoir hydropower) will be severely limited.

In such systems, power system flexibility can be enhanced by deploying energy storage along with other enhancements to legacy electric power systems: (1) transmission network expansion to increase the geographic footprint of balancing areas and better exploit spatiotemporal variations in demand and weather-driven VRE resource availability; (2) demand flexibility and demand response; and (3) deployment or retention of some dispatchable low-carbon generation. Here, we use systems optimization approaches to examine the value of energy storage for achieving the deep decarbonization of the electric sector and the implications for storage technology development and electricity market design under a wide range of technological and economic assumptions.

Specifically, we analyze power system evolution in three U.S. regions—the Northeast, Southeast and Texas, as well as, with less detail, at a national level. All these regions, and the United States as a whole, experienced significant reductions in carbon dioxide (CO_2) emissions from electricity generation between 2005 and 2018. These reductions reflect the combined effects of stagnant electricity demand; a large reduction in coal-fired generation in favor of natural gas generation, largely for economic reasons; and significant increases in VRE generation, importantly (but not exclusively) driven by public policy.

Given the central role for electrification in long-term U.S. decarbonization efforts, the model- based findings in this chapter primarily rely on electricity demand projections from a high-electrification scenario developed by the National Renewable Energy Laboratory (NREL) for its 2018 Electrification Futures (EFS) study. In NREL's high-electrification scenario, U.S. electricity consumption increases by a factor of 1.6 by 2050 relative to the 2018 level of roughly 4,000 terawatt-hours. Subject to these demand assumptions, we analyze power system evolution for different 2050 power system decarbonization targets, defined in terms of CO_2 emissions produced per kWh of electricity generated, for our three regions of the country in 2050.

In our study, we focus on four emissions constraints: 0 gCO_2/kWh, 5 gCO_2/kWh, 10 gCO_2/kWh, and 50 gCO_2/kWh. When contemplating the common goal of "net-zero" carbon energy systems, where the term "net-zero" is understood to allow for the inclusion of negative emissions technologies, the 5 gCO_2/kWh or even 10 gCO_2/kWh emissions constraint is likely more informative than the very strict 0 gCO_2/kWh constraint. While our analysis focused on grid decarbonization by 2050, achieving zero or net-zero carbon emissions from electricity generation sooner than 2050 would require more rapid shifts in the generation mix and possibly an expanded role for energy storage.

We found that the near-complete decarbonization of power systems can be achieved with VRE deployment, in conjunction with available Li-ion battery energy storage, along with infrequent use of dispatchable natural generation. At the same time, we find that full decarbonization based on deploying VRE and Li-ion storage technologies while ruling out any use of natural gas is significantly more expensive at the margin. It provides a compelling reason to focus public and private RD&D resources on further improving the cost and performance attributes of a range of technologies, including emerging long- duration energy storage (LDES) technologies, alternative low- or no-carbon generation technologies that are dispatchable, and negative emissions technologies that can remove CO_2 from the atmosphere.

While these broad observations apply across all regions studied here, our modeling reveals significant regional variation in system costs, optimal storage capacity deployment, and optimal generation mix under different emission constraints. The differences primarily reflect differences in the quality of wind and solar resources and thus in the cost of zero-carbon generating technologies in the three regions we examine. Therefore, the challenges of "getting to net zero" will vary across regions based on their resource endowments.

Due to data limitations, we did not model the demand-side impacts of very extreme weather events. Such events, which can affect both electricity demand and supply, are likely to become more important in the future owing to climate change. Due to computational tractability, we had to resort to approximating annual grid operations using representative weeks for two of the study regions using multi- zonal grid representation. Collectively, these factors, coupled with our assumption of perfect foresight, mean that our results likely underestimate the value of storage and the magnitude of storage deployment that would be cost-effective in low-carbon power systems.

At the same time, other assumptions in our modeling may contribute to results that overestimate the value of storage. First, we ignore use-based degradation of electrochemical storage. If degradation were included, it might limit the value of these storage resources. Second, our modeling does not consider the availability of bioenergy-based power generation with or without carbon capture or other dispatchable renewable generation sources such as geothermal. If such sources become available, their deployment could help minimize the cost impacts of going from near-complete decarbonization to full decarbonization and could significantly reduce the value of LDES. Finally, our analysis is based on least-cost investment planning for a future year (2050) with corresponding technology cost projections for that year. In reality, VRE and other resource investments will be added incrementally over time, likely leading to higher investment costs than were assumed here.

We conclude by highlighting the complexity of long-term investment planning aimed at efficiently achieving deeply decarbonized and reliable power systems and the importance of fundamental research to advance the state-of-the-art in models used for investment planning, as well as the need for system operators to continuously review and update their planning approaches to incorporate best available methodologies. System planning needs to account more effectively for variability in demand and supply, especially under extreme weather events, and for correlations between the supplies from individual generators in the portfolio and between total generator output and demand. This variability is likely to increase with climate change.

—Summary by Diana Degnan

Cristian Junge, Cathy Wang, Dharik S. Mallapragada, Howard K. Gruenspecht, Hannes Pfeifenberger, Paul L. Joskow, and Richard Schmalensee (2022), "Properties of Deeply Decarbonized Electric Power Systems with Storage", CEEPR WP-2022-003, MIT, February 2022.







Carlos Batlle, Tim Schittekatte, and Christopher R. Knittel (2022), "Power Price Crisis in the EU: Unveiling Current Policy Responses and Proposing a Balanced Regulatory Remedy", CEEPR WP-2022-004, MIT, March 2022.

Research.

Power Price Crisis in the EU: Unveiling Current Policy Responses and Proposing a Balanced Regulatory Remedy.

By: Carlos Batlle, Tim Schittekatte, and Christopher R. Knittel

For several months, electricity prices in the European Union (EU) have been at sustained and unprecedentedly high levels. The current energy crisis is first and foremost a natural gas crisis. However, as reference day-ahead electricity markets reflect the system marginal (opportunity) cost of generation often set by gas-fired plants, electricity prices have also attained sustained high levels. Figure 1 shows daily average day-ahead electricity prices for 2021 and the start of 2022 for a selection of European countries. The price dynamics have not been homogeneous across countries, due to the diverse levels of gas dependency and cross-border interconnections.

This situation has caused national governments to introduce temporary measures aimed at limiting the increase in end user electricity bills. A number of governments argue that this situation calls for a wider reform of electricity markets in the EU — beyond the mere introduction of temporary measures. Their central message is that the price paid for electricity by consumers shall be linked to the average cost of generation, instead of being set by the marginal generation technology (often gas-fired plants) as it is today. It is, however, unclear how governments plan to reach this objective without overhauling the fundamentals of electricity market design and without affecting power system efficiency both in the short run and long run.

After a thorough review of what has been said and done, we identify two approaches that are currently being implemented or proposed and that relate to the objective of linking prices paid by consumers to the average cost of generation: taxing of (alleged) windfall profits (Spain, Romania, and Italy) and mandating auctions for bilateral contracts with insufficient demand-side pressure or regulated prices (France, Spain, Bulgaria, Portugal, and Italy). These two measures also go beyond the European Commission's toolbox for actions and support that was published in October 2021 (European Commission, 2021). However, at the time of this writing, a web article issued on February 18 leaked a draft of an upcoming communication from the EC (Taylor,

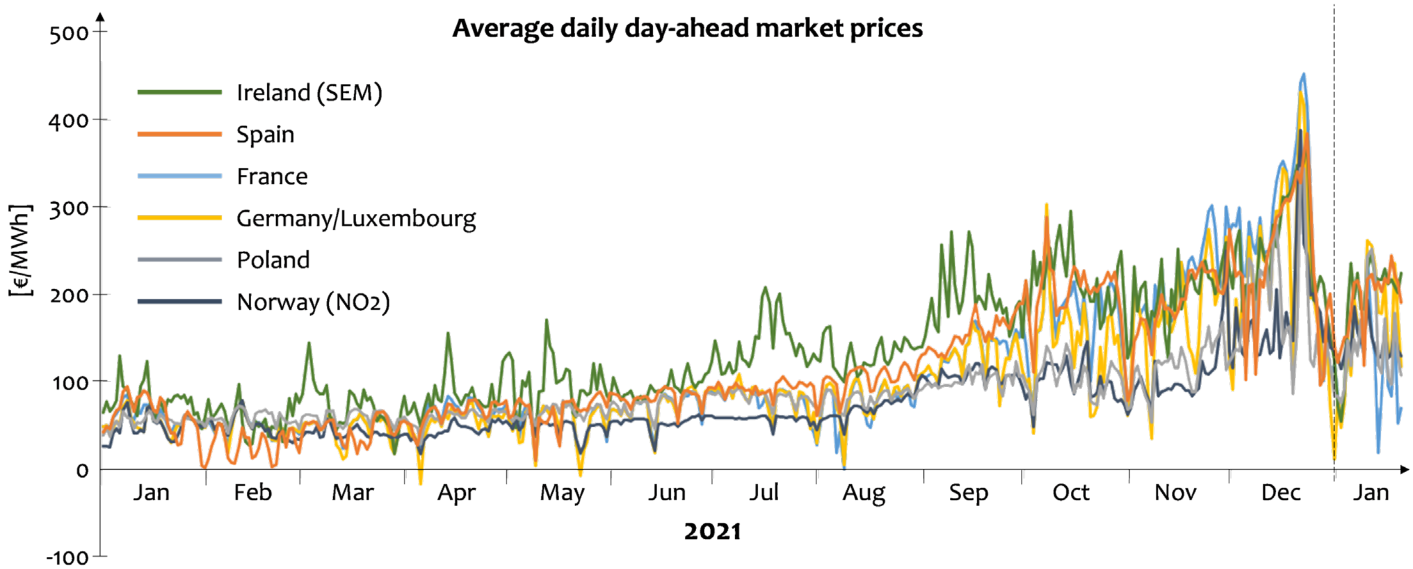


Figure 1. Average daily spot prices in a selection of European countries from 01/01/2021 to 01/20/2022.
Own elaboration based on ENTSO-E (2022).

2022). In it, two of the annexes develop guidelines on market interventions which, in our view, can be considered as at least remarkable (if not jaw-dropping) and certainly not much aligned with the measures promoted in the toolbox the EC published in October.

We criticize the implementation of windfall profit taxes and mandated auctions for bilateral contracts by discussing their static and dynamic implications. In the short run, these measures risk altering the efficient dispatch. More important than any static issue are the dynamic issues; they increase the regulatory risk and thus the required return on capital for investors, which is especially relevant as renewables are very capital intense. As such, they will make the EU energy transition slower and costlier. We also discuss two other potential measures that might be pursued, but which we do not consider as efficient approaches either: volume-restricted auctions for renewables and negotiated long-term contracts on behalf of consumers. The former conflicts with third party access rules and slows down the deployment of renewables, the latter will end up being a bad deal for consumers in the long run.

Finally, we develop policy and regulatory recommendations. We start by supporting the measures proposed by the European Commission in its toolbox: the introduction or extension of energy poverty measures, the reduction of taxes and levies in the bill, and the acceleration of the deployment of renewables. A silver lining in this energy crisis could be the permanent reduction of levies in the electricity bill to foster the electrification of transport and heating.

However, since the economic and socio-political situation is diverse across the EU, we explore alternatives for the Member States in which those measures are considered insufficient or even infeasible. In this context, and when considering the endemic lack of liquidity in electricity forward markets of contracts of sufficient length to adequately protect end users, we propose a regulatory-driven centralized auction in which a central entity buys lagged long-duration call options from generators on behalf of a subset of end users. By introducing such options, the risk of sustained high electricity prices is transferred from risk averse consumers (and indirectly the risk averse government) to less risk averse market parties (at least from unexpectedly high prices) which would create an additional incentive to invest in generation assets (e.g., renewables) and/or enter into long-term gas contracts.

We term this financial product "stability options", an Asian option with monthly fixings. The goal of stability options is to fulfill the objective of hedging those tranches of end users from extreme and long-lasting price shocks (keeping the monthly bills within acceptable limits), while respecting the basic market competition rules, avoiding any distortion of the short-term market price signal, and more importantly, without hurting the regulatory credibility of the European internal market.

Finally, please note that stability options are a financial product and not a subsidy nor a capacity remuneration mechanism. Regarding the former, the option premium is allocated to the end users deemed in need of bill protection. Regarding the latter, stability options are in many dimensions different from reliability options (Pérez-Arriaga, 1999) that have been implemented for adequacy purposes in Italy, Ireland, and New England. Different issues require different solutions. Most importantly, compared to reliability options, stability options are settled monthly and not hourly, their strike is typically lower (representing the monthly bill cap and not the hourly price cap), and they are issued on behalf of a subset of end users that are deemed to need bill protection and not (typically) the entire load.

Research.

Technology Neutral vs. Technology Specific Procurement.

By: Natalia Fabra and Juan-Pablo Montero

A principal (e.g., a regulator or a firm) needs to procure multiple units of a good or service that can be produced with heterogenous technologies. How should she procure these units? Should she procure them by posting separate prices for each technology? Or should she instead run technology-specific or technology-neutral auctions? In answering these questions, what are the trade-offs involved and how do they depend on the nature of the available technologies and the extent of information asymmetry regarding their costs?

This problem is motivated by a fundamental challenge faced by many governments around the world in their efforts to reduce carbon emissions: how to accelerate the deployment of renewable energies (e.g., solar, wind, or biomass) and storage facilities (e.g., pumped storage or batteries) at the lowest possible fiscal cost (Council of European Energy Regulators, 2018).

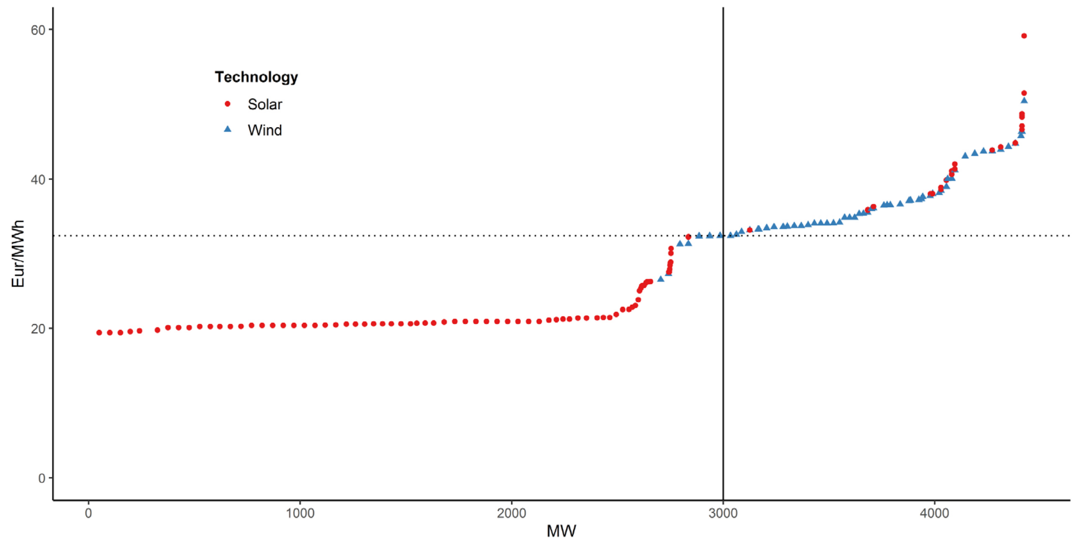
In practice, several instruments have been used (and continue to be used) for such purposes, e.g., price-based instruments like Feed-in Tariffs and Feed-in Premia, or quantity-based instruments such as auctions or tradeable quota obligations. Some of these instruments have treated technologies separately, whether by type, location and/or scale. Other instruments have been technologically neutral. And yet other instruments have relied on hybrid approaches (so called technology banding), e.g., by deflating the bids associated to some technologies but not others, or by granting relatively more (green) certificates to some technologies.

Whether governments are aware of it or not, these choices involve a clear trade-off between efficiency and rent extraction. On the one hand, as the European Commission (2013) has pointed out, well-designed technology-neutral approaches are more effective in finding the cheapest technology sources, but they may also result in over-compensation. Indeed, by not discriminating among heterogenous sources, the authority may be leaving too much rents with some suppliers, making decarbonization unnecessarily costly. On the other hand, a well-designed technology-specific approach might fail in efficiently discriminating across technologies due to asymmetric information regarding their costs. Without ex-ante knowledge of the costs of the various technologies, setting ex-ante prices or quantities might result in inefficient but also costly allocations given that the quantities allocated to each technology do not adjust ex-post.

This trade-off between efficiency and rent extraction has been central to the regulation and procurement literature (Laffont and Tirole, 1993; Segal, 2003). And although also recognized in the realm of renewable energy procurement (EC, 2013; CEER, 2018), its impact on the preferred regulatory instrument to promote renewables has not been systematically analyzed. Furthermore, following Weitzman (1974)'s seminal work, the regulation literature has assessed the relative performance of prices versus quantities, but it has done so in the case of a single technology or under the assumption that the regulator only cares about productive efficiency, thus leaving no scope for the rent-efficiency trade-off to play a role.

Yet, in the context of the simple linear schemes commonly used in practice, it is not clear whether quantity-based approaches (e.g., auctions) should be preferred over price-based approaches (e.g., feed-in tariffs), and how this choice is affected in the presence of multiple technologies (e.g., solar and wind, or pumped storage and batteries). Furthermore, it is not clear when and why rent extraction concerns (i.e., the risk of over-compensating some sources) may dominate efficiency concerns (i.e., the risk of departing from cost minimization), and to what extent these concerns are best managed

Figure 1: The expected aggregate supply curve for solar and wind investment projects in Spain, 2019



Notes: This figure displays the expected (long-run) average cost curves for solar (red dots) and wind (blue triangles) projects.

through technology banding or technology separation.

This paper provides a sufficiently general framework in which all these questions can be addressed. This framework should prove useful for policy makers by helping them understand, from a purely economic-regulatory perspective, when and why a particular approach should be preferred over another. Our model allows us to conclude that a well-informed regulator should always run separate auctions, with the allocation to each technology chosen in a way to preserve cost minimization. A similar prescription should be followed if the two technologies are subject to similar shocks because cost minimization is not in danger either. As incomplete information mounts, she may reverse her decision in favor of technology neutrality unless the cost for the government of not discriminating is too large. This ultimately depends on the amount of over-compensation to the more efficient suppliers, which depends on how asymmetric their costs are, as well as on the unit price of this over-compensation, i.e., the shadow cost of public funds.

Using historic data on renewable production across fifty Spanish provinces, we computed the expected production of each investment project over its lifetime (which we assume equal to twenty five years). A project's (long-run) average cost is given by the ratio between its investment cost and its expected production. By ranking projects of the same technology in increasing average-cost order, we construct the aggregate (long-run) supply curve of such technology.

Figure 1 plots the expected supply curve, i.e., for the pair (0,0) of cost shocks. As it can be seen, the average costs of solar plants (denoted by red dots) tend to be lower than the average costs of wind plants (denoted by blue dots). However, the average cost curve of solar plants becomes very steep as we approach the capacity constraint, given that the most expensive projects are the small ones located in the least sunny regions. The average cost curve of wind plants tends to be higher but flatter, as all wind projects tend to be similar in size and they tend to be located in the most windy regions only.

Our results show that the use of well-designed technology-specific auctions would result in superior outcomes as compared to technology neutrality or technology banding. However, this result may not extend to other settings in which the costs of deploying the various technologies are less asymmetric and are more negatively correlated, and if the regulator cares less about minimizing firms' rents.

Natalia Fabra and Juan-Pablo Montero (2022), "Technology Neutral vs. Technology Specific Procurement", CEEPR WP-2022-005, MIT, March 2022.

Abdullah Alawad, Pablo Dueñas, Ahmad Alabdulkareem, and Carlos Batlle (2022), "Coping with National Fuel Subsidies in Regional Power Markets: Application to the Gulf Cooperation Council Interconnector", CEEPR WP-2022-006, MIT, March 2022.

Research.

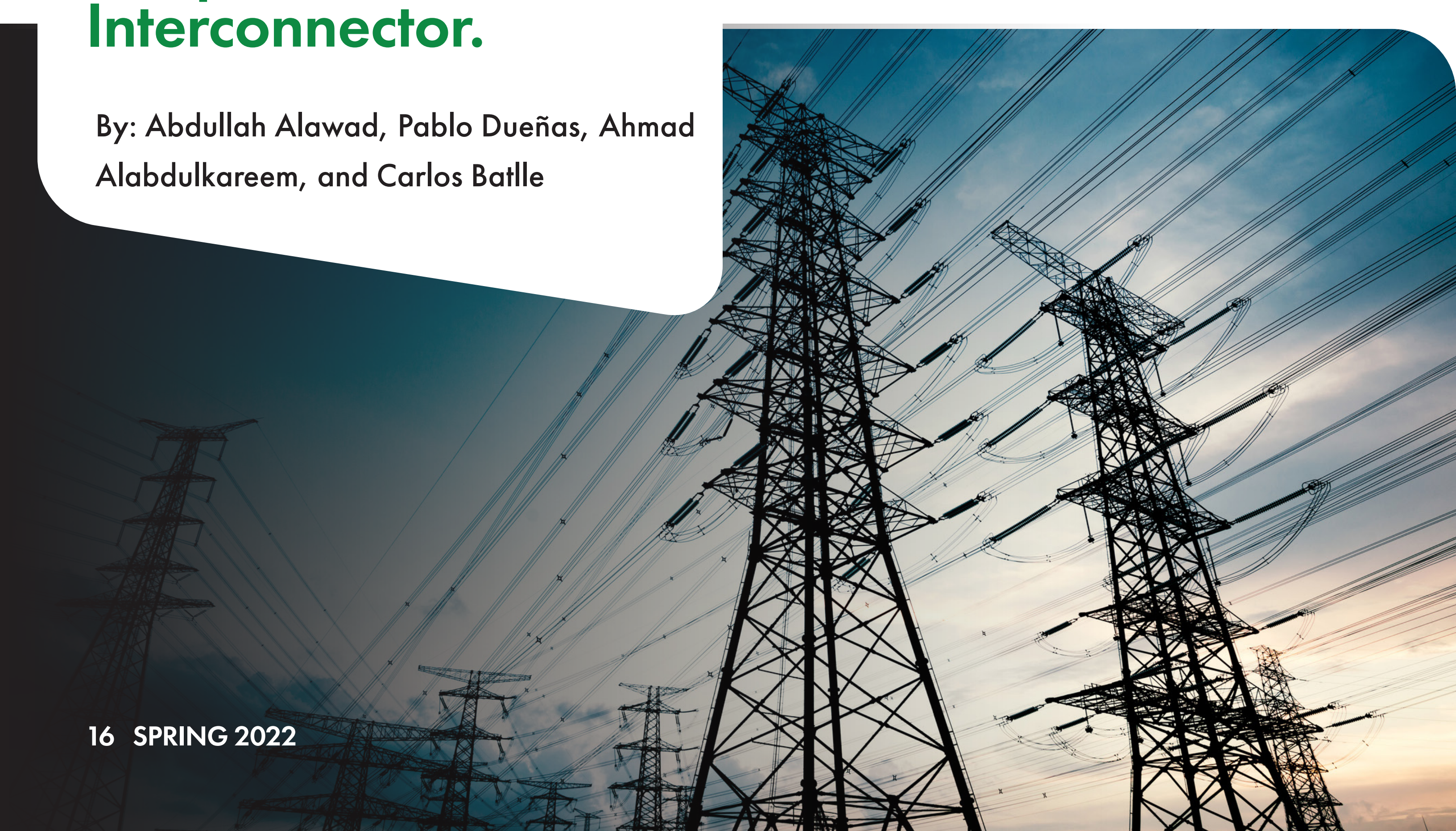
Coping with National Fuel Subsidies in Regional Power Markets: Application to the Gulf Cooperation Council Interconnector.

By: Abdullah Alawad, Pablo Dueñas, Ahmad Alabdulkareem, and Carlos Batlle

One key aspiration for countries the world over in recent decades has been the institution of regional markets to integrate several national/state power grids. In addition to improving short-term reliability, integrating contiguous markets can lower power supply costs through coordinated operation and eventually integrated energy resource investment planning. The materialization of such benefits necessitates thoughtful market design informed by technical, economic and institutional analyses of the regional system. More specifically, market design must address not only the technical issues that condition the performance of the regional power system, but also other constraints associated with sociopolitical objectives, deemed to be a high priority by some member states.

Trading in power exchanges is thus limited not only by grid constraints and agents' operational and economic characteristics, but as well as by other conditioning factors that must be borne in mind when concluding supply agreements or participating in power auctions. So the design of all the mechanisms in place in organized markets for electricity, from capacity markets to day-ahead, intraday and balancing markets need therefore to allow accommodating such constraints in the most efficient way possible.

One of the most prominent and widespread such factors are energy subsidies, i.e. measures aimed at keeping prices for electricity end users below market levels. Traditionally regional markets regulation has aimed at banning such subsidies, to properly ensure healthy competition and maximize short- and long-term economic efficiency. However, as we evidence by reviewing the different regional markets implemented not just in the EU and the US but worldwide, experience increasingly shows that the trend does not lead to the removal of these subsidies, but quite the contrary. As a result, it is worth looking for innovative regional market design solutions to take the best of the integration of different



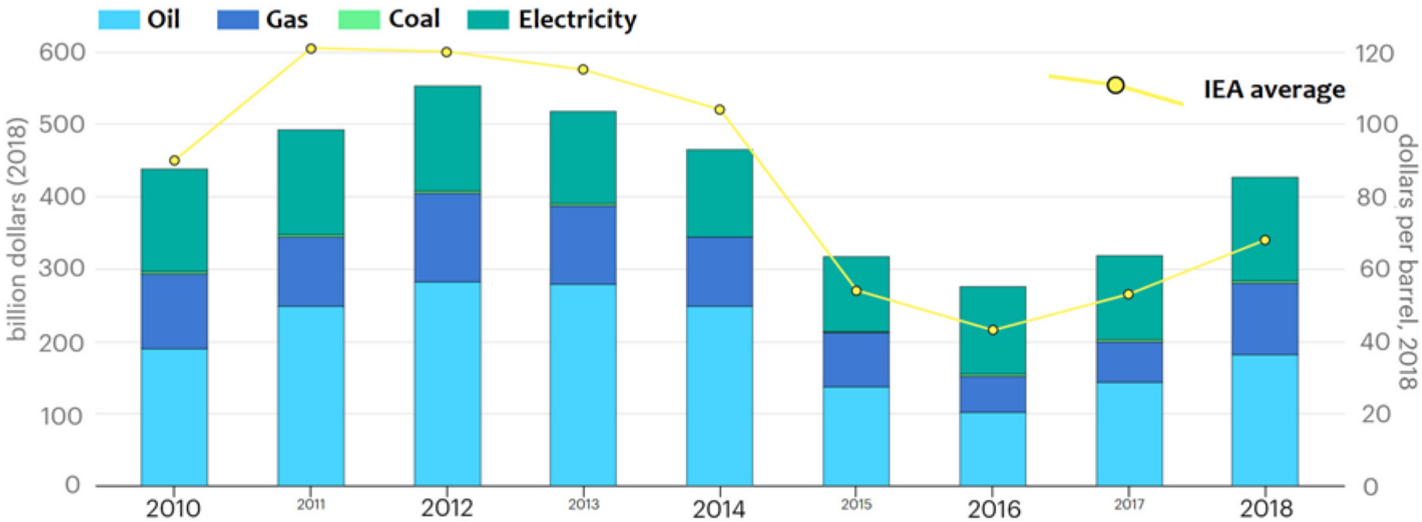


Figure 1. Subsidies for fossil fuel, 2010-18 (Matsumura and Adam, 2019)

power system, while coping with the existence of this sort of national subsidization mechanisms.

Figure 1 shows that in spite of obvious benefits to be reaped by eliminating subsides, no significant or even minimal medium-term drop has occurred. Over the 2008-2018 period, the overall energy-related subsidies in the EU27 MS have increased by 67%. Nor is a drop in subsidies to be reasonably expected in light of recent reactions to rising oil prices: in 2018 fossil fuel subsidies totaled values last seen in 2014. As Figure 1 shows, generation-side fuel subsidies have routinely accounted for a substantial share of that total.

In particular, we focus on one of the key pieces of regional markets design, the pricing mechanism in the day-ahead market. This design element shows how different bidding formats condition efficiency gains in the presence of uncertainty in electricity markets. In the presence of any sort of subsidization policy, designing mechanisms to optimize price calculation subject to these higher order constraints happens to be instrumental. To achieve this aim, we propose original and simple bidding conditions and market clearing methods whereby one of two prices may be attributed to each generating unit depending on whether final delivery targets domestic or export demand. The proposal, designed to favor transitioning to integrated regional markets as hopefully countries gradually eliminate subsidies, is illustrated with a full-scale case study, the Gulf Cooperation Council Interconnection, where the reluctance to comply with that limitation might be underlying governments' unwillingness to commit to regional integration.

The algorithm proposed for a bidding and clearing scheme, tested in Gulf Cooperation Council Interconnection case study, aims to fell or lower this barrier to the establishment of transnational markets and pave the way for progress in that regard. The export bidding format we propose would enable generating units to offer their output at different prices on different regional nodes. Its underlying intention is to allow generating units to express a willingness to sell their output at one price in the local/domestic node or zone and at another for exports. As the case study shows, the proposal envisages the inclusion of generating units sited in countries where generation-side fuel subsidies are in place for domestic demand only. Under the terms of the proposal, such units would be in a position to export their output when below the auction cut-off price, while not actually needing to "export" the subsidy.

Although the regional integration of electric power systems is instrumental to maximizing power generation efficiency in both the short and long term, in a number of jurisdictions generation-side fuel subsidies constitute a formidable obstacle to successful market operation. Solutions are required to enable regional markets to adapt to the presence of subsidies. We review this issue and suggest an initial mechanism that would enhance regional economic dispatching efficiency. The market design we present can he viewed as a useful tool for eliminating or at least lowering that hurdle. By implementing the bidding format and market clearing method proposed, countries could transition to integrated regional markets while gradually paring down their subsidies.

—Summary by Diana Degnan

Research.

Electricity Sector Policy Reforms to Support Efficient Decarbonization.

By: Howard K. Gruenspecht, Hannes Pfeifenberger, Paul L. Joskow, and Richard Schmalensee

In future decarbonized power systems, wind and solar generation will be much more important than today. Wind and solar generators, often collectively labeled VRE (variable renewable energy), are intermittent: their output is both variable and imperfectly predictable because it is primarily determined by variations in wind and solar resource availability rather than by system operators' decisions to balance supply and demand by moving up and down a reasonably stable bid-based or marginal-cost-based economic dispatch curve as demand varies (the way system operators now manage output from mostly fossil-fuel generation resources). As a consequence, future systems will need to cope with unprecedented supply fluctuations to balance supply and demand reliably. Energy storage will play an important role in balancing supply and demand reliably in systems with high VRE penetration by filling the gaps between exogenous variations in VRE supply and demand.

Because of the key role storage can play in balancing supply and demand and thus maintaining reliability in systems with high VRE penetration, and because of substantial projected declines in the costs of storage technologies, storage should be much more important in future decarbonized power systems and play a larger variety of roles than it does today. The methods used by today's system operators and the associated regulatory rules and policy regimes that constrain them were developed for power systems that relied primarily on dispatchable generators and in which storage was of negligible importance. Investing in and operating storage so that it effectively plays appropriate roles in future decarbonized power systems will pose novel operational and financing challenges. It will also pose challenges in terms of regulation and market design.

We find that two features of efficient, decarbonized systems will have particularly important implications for the design of markets and governance institutions. The first is a very different distribution of wholesale spot prices with many hours of very low prices, along with a few hours of very high prices. The second is that storage, both grid-scale and at customer premises, is a potential substitute for, or complement to, essentially all other elements of the power system.

State regulators should develop rules that allow owners of storage (and generation) assets installed on customer premises to sell services to the vertically integrated utilities within whose geographic footprint they are located under appropriate terms and conditions that facilitate efficient investment in and use of "behind-the-meter" generation and storage.

Market rules will need to be developed to adapt capacity mechanisms for the "effective load carrying capability" of VRE generation and to correctly determine the capacity value that storage resources can provide to meet reliability standards. ISOs should either (1) redesign existing capacity mechanisms as they apply to VRE generation and storage, taking into account the joint stochastic properties of VRE generation and demand and the fact that storage is energy-limited, or (2) replace those capacity mechanisms with an increased reliance on integrated resource planning that properly accounts for these factors.

Howard K. Gruenspecht, Hannes Pfeifenberger, Paul L. Joskow, and Richard Schmalensee (2022), "Electricity Sector Policy Reforms to Support Efficient Decarbonization", CEEPR WP-2022-007, MIT, April 2021.

Storage can provide benefits for transmission and distribution systems that can be particularly important in rapidly growing systems. To efficiently realize these benefits, federal regulators should integrate storage into transmission planning processes, while state regulators should require the integration of storage in distribution system planning. In addition, storage devices should be allowed to provide wholesale power market services where physically possible.

In terms of retail rates, the best approach to ideal, efficient, and equitable retail rate design is not obvious at this point, though it is clear that overall reliance on uniform volumetric charges must be reduced, and it is likely that a larger fraction of revenues must be raised by charges that do not vary with current consumption. Significant additional research is called for. The U.S. Department of Energy (DOE), in cooperation with state regulators, should increase support for independent work aimed at (1) devising efficient and equitable retail rate designs for high-VRE systems with storage and (2) encouraging their widespread adoption. Even if there is consensus in the research community about the best retail rate designs, it will be largely up to state regulators to implement the necessary reforms. Some customers will benefit from retail rate design changes while others will see higher costs. Retail competition in some states adds a further layer of regulatory complexity. Efficient mechanisms to reduce any adverse distributional impacts should be given serious consideration.

We recommend that state and federal regulatory agencies receive increased staffing and budgets to enhance their capabilities to design and implement regulatory mechanisms that can guide the transition to efficient high-VRE systems with storage. Devising state and federal rules that are both efficient and aligned will not be simple, but it will be essential for the high-VRE systems of the future. The Federal Energy Regulatory Commission (FERC), state regulators, and ISOs should reform and align market rules to enable efficient participation—in wholesale energy and ancillary service markets, as well as in capacity markets—by providers of both grid-based storage and distribution-level generation and storage (including from facilities located on customer premises). These reformed rules should accommodate the participation of aggregators in wholesale markets.

—Summary by Diana Degnan

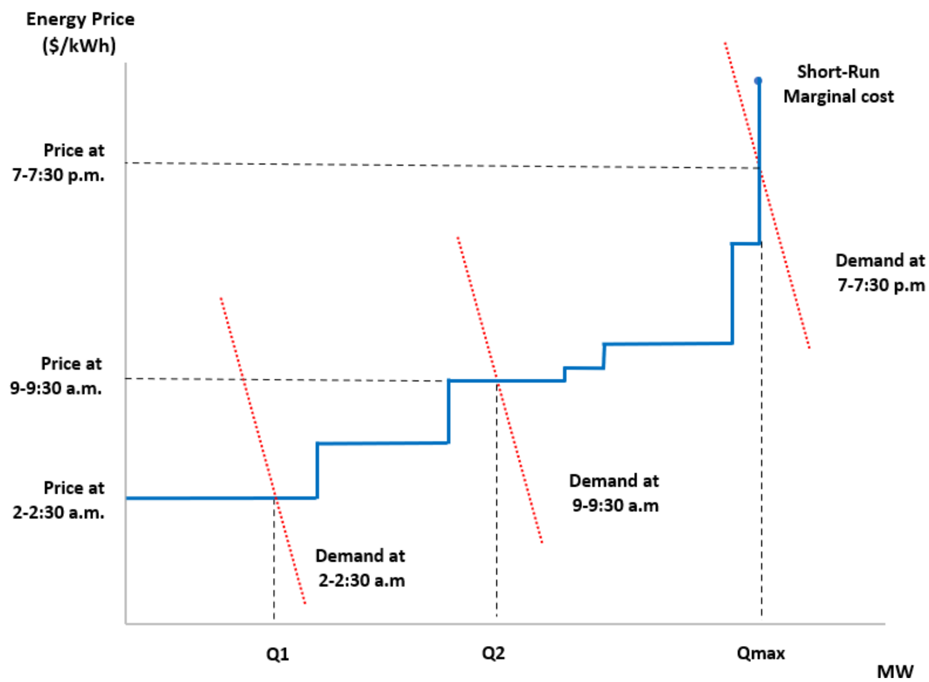


Figure 1. A contemporary electricity market in the short run.

In today's competitive electricity markets, wholesale prices reflect generators' marginal costs of producing electricity at each potential level of demand. In short, the economic dispatch curve is upward sloping and reasonably stable.

Alexander MacKay and Ignacia Mercadal (2022), "Deregulation, Market Power, and Prices: Evidence from the Electricity Sector", CEEPR WP-2022-008, MIT, April 2022.

Research.

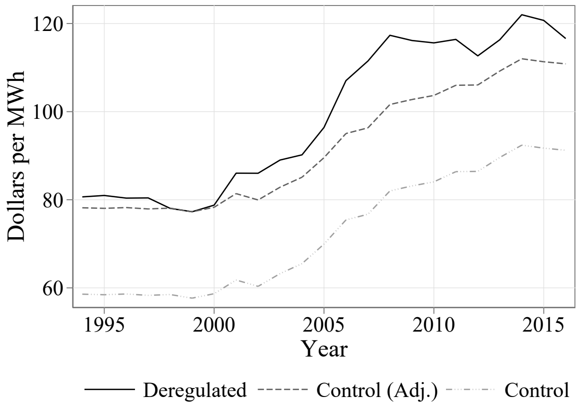
Deregulation, Market Power, and Prices: Evidence from the Electricity Sector.

By: Alexander MacKay and Ignacia Mercadal

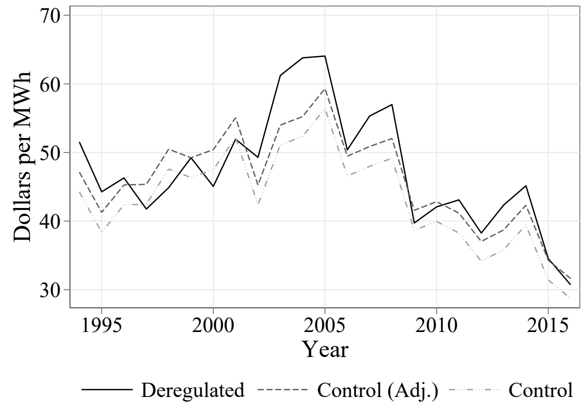
In the late 1990s, several states in the United States started to restructure the electricity sector, replacing regulated and vertically integrated utilities by wholesale and retail markets open to many competitors. Over 20 years later, we have yet to fully understand the consequences of these efforts (Bushnell et al., 2017). The existing evidence has primarily focused on the impacts on costs, and has shown modest reductions in generation costs as a result of restructuring (Fabrizio et al., 2007; Davis and Wolfram, 2012; Cicala, 2015, 2022). The price effects of restructuring have not been extensively studied (Borenstein and Bushnell, 2015; Bushnell et al., 2017).

Importantly, the impact of deregulation on prices is theoretically ambiguous. Market-based prices provide incentives for profit-maximizing firms to reduce costs, but firms that have market power also have an incentive to increase markups but choosing prices above marginal costs. When cost efficiencies from deregulation are outweighed by an increase in markups, market-based prices can be higher than regulated rates. Thus, without efforts to protect and strengthen competition, such as regulatory oversight and antitrust enforcement, markets may be worse for consumers. Regulators must consider the tradeoff between production efficiencies and higher markups when deciding whether to transition from regulated monopolies.

We study this tradeoff in the context of the deregulation of the U.S. electricity sector. Deregulation efforts included the introduction of market-based prices and restructuring measures to introduce competition into the upstream generation market and the downstream retail market. Contrary to the objectives of deregulation, we show that prices increased in deregulated markets, despite a modest reduction in marginal and average variable costs (See Figure 1). Thus, the increase in markups dominated the efficiency gains, indicating the widespread exercise of market power. Our findings show that deregulation does not necessarily lead to lower prices to consumers.



(a) Retail Prices



(b) Marginal Fuel Costs

Figure 1. Aggregate Measures of Electricity Prices and Generation Costs
Panel (a) plots the quantity-weighted default retail price for investor-owned utilities in deregulated states (solid line) and in control states (dotted light grey line). Panel (b) plots the average fuel costs of generation for all generating facilities that in 1994 belonged to utilities in deregulated states (solid black line) and control states (dotted line). The dashed line in both panels plots retail prices and fuel costs for control states after adjusting for level differences in 1999.

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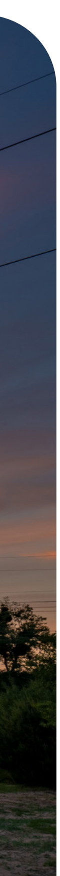

We construct a unique dataset that covers the annual electricity flows from generation to final consumption for each electric utility territory from 1994 through 2016. This dataset offers a novel perspective of the evolution of the U.S. electricity market after deregulation. Importantly, our dataset includes purchases through bilateral contracts in addition to purchases in the centralized wholesale markets run by independent system operators (ISOs), which have been the focus of the previous academic literature. From 2000 through 2016, the vast majority—over 85 percent—of wholesale electricity was sold with such contracts, outside of centralized markets. Thus, our data allows for a broader analysis of prices and the interactions between upstream and downstream market participants.

Using this data, we compare utilities that were subject to state-specific deregulation policies to similar utilities in other states that remained tightly regulated with a difference-in-differences matching approach (Deryugina et al., 2019). We find substantial price increases for consumers in deregulated states relative to consumers in regulated states. On the other hand, marginal costs declined in deregulated states, indicating that higher prices are driven by higher markups. Overall, we estimate that gross markups—retail prices minus the marginal cost of generation—increased by 15 dollars per MWh from 2000 to 2016. Relative to 1999 price levels, this change in markups corresponds to a 19 percent increase in prices over the period.

Crucially, our data allow us to examine the impacts in wholesale markets, providing greater insight into the underlying mechanisms that explain this increase. We find that wholesale markups increased by more than the decline in generation costs, leading to higher wholesale prices. Retail markups also increased modestly. Wholesale markups increased by roughly 9 dollars per MWh, representing over 60 percent of the overall increase in gross markups. Thus, we find market power in the generation market to be the primary driver of price increases.

It is important to note that we measure market power using markups, the difference between price and marginal cost. Market power can exist even with competitive market mechanisms, such as auctions, when there are a limited number of potential suppliers. Thus, deregulation can lead to higher prices due to entry barriers and other market features that lead firms to charge markups in equilibrium.

To distinguish market power from competitive rents, which could arise in a competitive market in the presence of cost heterogeneity, we consider the costs of the most expensive plants in the market. In a perfectly competitive market, prices should equal the costs of the most expensive plants. Consistent with market power, we find substantial increases in markups over the highest-cost plants. We additionally present several indirect tests of market power that point to market power at the wholesale level as the main driver of price increases.

We also show that the market restructuring intended by deregulation was delayed for several years. Despite the divestiture of generation assets, utilities maintained a high degree of vertical integration through contracts and umbrella ownership, where different companies are subsidiaries of the same parent/holding company. Thus, we distinguish between apparent deregulation—the share of a market supplied by companies other than the incumbent utility—and effective deregulation-the share of a market supplied by companies unaffiliated with the incumbent. In wholesale markets, we find that the use of contracts with affiliated companies delayed the onset of effective deregulation by many years, compared to apparent deregulation. In retail markets, caps on retail rates and other factors slowed the introduction of competitive supply. Consistent with these delays, we observe a much larger impact on prices once restructuring measures are fully in effect. Thus, distinguishing between apparent deregulation and effective deregulation can be important to accurately measure policy impacts.

We believe we are the first to show that electric deregulation in the U.S. has resulted in increased prices from market power, and that this effect has dominated cost efficiencies. Though there was early awareness of the potential for market power in deregulated markets, the fact that the effects of market power could considerably exceed the savings from increased cost efficiency is surprising. Our findings point to the importance of careful market design and market monitoring in electricity markets to guarantee that consumers benefit from the cost savings that resulted from deregulation.

Jorge Alé-Chilet, Cuicui Chen, Jing Li, and Mathias Reynaert (2022), "Colluding Against Environmental Regulation", CEEPR WP-2022-002, MIT, January 2022.




Research.

Colluding Against Environmental Regulation.

By: Jorge Alé-Chilet, Cuicui Chen, Jing Li, and Mathias Reynaert

The case centers around components of nitrogen oxide (NOx) cleaning technology called Selective Catalytic Reduction (SCR). The SCR system converts harmful NOx into harmless water and nitrogen by adding a Diesel Exhaust Fluid (DEF) to the exhaust. SCR requires a large quantity of DEF to neutralize NOx. The automakers admitted to agreeing upon DEF tank sizes and rates of DEF consumption, which made their vehicles less effective in removing NOx emissions.

We first ask why automakers might benefit from collusion over NOx cleaning technology in their diesel vehicles. We write a model with a regulator who enforces environmental and antitrust rules. The regulator faces an industry of multiple firms and is imperfectly informed about the firms' technology, environmental compliance, and communication. Environmental compliance is costly for firms because the emission control system trades off with trunk space, which consumers value. Our model shows that collusion can help firms reduce their expected penalties for undercompliance with environmental regulation via three mechanisms. We suggest three mechanisms for how firms achieve a reduction in their expected penalties: (i) diffusing their responsibility and thus reducing the penalty in the event of being caught, (ii) reducing the probability that their competitors report them by giving competitors skin in the game, and (iii) reducing the probability that environmental undercompliance is detected.

We next combine our model with data on vehicle sales from the European automobile industry from 2007 to 2018 to quantify the impact of collusion on automakers' profits, consumer surplus, and societal health damages. We find that collusion increased the automakers' profits by between 0.68 and 2.83 billion euros and reduced their expected noncompliance penalties by at least 188 to 976 million euros. Buyers of the more polluting vehicles benefit from collusion because they have access to cheaper vehicles with trunks that are not reduced in size with large DEF tanks. The benefits of collusion to the automakers and diesel vehicle buyers come at the cost of health damages inflicted on everyone in society who breathed the additional air pollution. Our empirical estimates show the societal damages from air pollution outweigh the private benefits from this collusive arrangement. Our damage calculations are in line with those by the European Commission before leniency, settlement, and novelty discounts.

Our study of the diesel vehicle NOx-cleaning antitrust case has implications for U.S. policy. The European Commission ruled that the firms' conduct violated European competition rules, specifically, Article 101(1)(b) of the Treaty on the Functioning of the European Union. Although antitrust laws differ in wording and scope in the U.S., discourse among lawmakers, regulators, and scholars is increasingly focused on whether antitrust concerns should be broadened beyond consumer welfare and pricing to include issues such as innovation, investment, and technical development. Alternatively, given our findings that collusion helps firms reduce their expected noncompliance penalties, environmental laws in the U.S. could be updated to include fines for group or joint behavior.

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Paul L. Joskow (MIT)
James H. Stock (Harvard)

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Ken Laberteaux (Toyota Research Institute)
Frances Sprei (Chalmers University)

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Howard K. Gruenspecht, Hannes Pfeifenberger, Paul L. Joskow, Richard Schmalensee, April 2022

WP-2022-006
Coping with National Fuel Subsidies in Regional Power Markets: Application to the Gulf Cooperation Council Interconnector
Abdullah Alawad, Pablo Dueñas, Ahmad Alabdulkareem, and Carlos Batlle, March 2022

WP-2022-005
Technology Neutral vs. Technology Specific Procurement
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Carlos Batlle, Tim Schittekatte, and Christopher R. Knittel, March 2022

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WP-2022-002
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Why Do Firms Issue Green Bonds?
Julien Xavier Daubanes, Shema Frédéric Mitali and Jean-Charles Rochet, January 2022

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Large Scale Wind Power Investment's Impact on Wholesale Electricity Markets
Ömer Karaduman, December 2021

WP-2021-019
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Lassi Ahlvik and Matti Liski, December 2021

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