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MIT CEEPR Newsletter

MIT Center for Energy and Environmental Policy Research

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Starting on inauguration day, President Donald J. Trump has followed through with campaign promises to initiate the reversal of energy and environmental regulations issued under his predecessor. Several executive orders, memoranda, and other actions have since targeted the regulatory legacy of the previous administration, directing key agencies to review, revise or rescind elements of the dense regulatory framework currently governing energy production and use in the United States.

Litigation and procedural constraints will slow down and, in some cases, halt this regulatory reform agenda, and a number of states and municipalities will exercise their powers to replace some of the federal mandates and incentives that are suspended. But the changes will nonetheless be far reaching, from discontinued use of the social cost of carbon as a metric in regulatory impact assessments to more relaxed environmental standards for coal, oil and gas production on federal lands.

As always, such sweeping policy change will come with risks and opportunities, and no shortage of uncertainty for those sectors seeking a predictable policy context for long term investment decisions. But as anyone familiar with recent energy trends in North America will also attest, many of the most consequential developments have not been driven by federal policies as much as by changing technology costs and other fundamental dynamics shaping regional and global energy markets.

Robust energy policy research will therefore be critical to better understand the real potential and limitations of federal policy change, and the MIT Center for Energy and Environmental Policy Research (CEEPR) will, as always, offer a venue for informed debate on these important issues, contributing objective, fact-based analysis and drawing on the valuable insights from its Associates in the public and the private sector.

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CEEPR Welcomes Six New Associates

by: Joshua Hodge

CEEPR seeks to expand its cohort of Associates by recruiting firms to join the Center who share our view that high-quality economics research is essential to informing decision-making under uncertainty. As important aspects of energy and environmental policy remain in flux worldwide and conflicting signals emerge from U.S. Federal and State-level energy and environmental policy-makers, we think that CEEPR's mission to promote objective, fact-based analysis and provide a venue for balanced debate is more important than ever.

Pursuit of this mission is made possible by the intellectual and financial support of our Associates. I am therefore pleased to announce that six additional firms have joined CEEPR as Associates since our Fall 2016 Research Workshop. The ClearPath Foundation, Eni, General Electric, IHI, National Grid and PSEG will each bring valuable questions and insights to our workshops and research program.

In order to further enhance opportunities for Associates to engage more formally with CEEPR, we are expanding the biannual Associates Meeting to two hours beginning with a working lunch on the first day of the Spring 2017 Research Workshop. Please join me in welcoming CEEPR's new Associates and expressing my gratitude to the Center's many long-time supporters.

To learn more about becoming a CEEPR Associate or for a full listing of CEEPR's Associates please visit us at the link below: http://ceepr.mit.edu/support/associates

CLEARPATH

eni

GE

IHI

nationalgrid

PSEG

E2e Project Update: Solving Externalities by Incenting Workers Directly

by: Leila Safavi

While many studies have focused on how capital improvements or market-based instruments can improve energy-efficient outcomes in firms, a new E2e working paper[1] by Greer Gosnell, John List and Robert Metcalfe explores the possibility of using incentive structures for employees to encourage conservation activities in the workplace.

Partnering with Virgin Atlantic Airlines, the authors conducted a large-scale randomized control trial to evaluate the impact of various performance measures on the fuel efficiency of pilots. Researchers identified fuel-relevant decisions made in the pre- to post-flight stages and randomly assigned pilots into a control group or one of three treatment groups. Each of the treatment groups received one or more of the following interventions: mailed performance feedback, personalized achievement targets and donations made to charity for completed monthly targets.

The authors estimate that interventions saved nearly 8,000 metric tons of fuel over the eight-month experimental period and found that the program would be highly cost efficient for airlines, with a marginal abatement cost of -$250 per ton of carbon. Results showed that receiving feedback moderately improved pilots' fuel-efficiency in all three stages, and the inclusion of personalized targets had a large additional effect that was not augmented by pro-social incentives.

However, awareness of the study prompted behavioral changes in the control group as well; control pilots were more likely to meet fuel-efficient objectives by nearly 50% in two of the three behavioral measures during the experiment, indicating a robust Hawthorne effect. The researchers find that the Hawthorne effect persisted after the experimental period, suggesting that sustained energy-efficient behaviors may stem from an updated understanding of the energy-related decisions faced by firms.

[1] For the full paper, please visit http://e2e.mit.edu/ to learn more about this project.

Estimating the Future Supply of Shale Oil: A Bakken Case Study

by: James L. Smith

How much shale oil do we have left? And how much of that can be recovered economically?

The volume of future U.S. shale oil production depends directly on the number and productivity of potential drilling sites that remain to be tapped. Although estimates of future production must be forward looking, we show how the observed sequence of historical drilling results leads naturally to a statistical estimator of the remaining volume of technically recoverable resource.[1] By studying the dynamic process of resource depletion, we are able to project future drilling results and calculate the expected volume of technically recoverable resources. An indication of the productivity of remaining drilling sites is also obtained, which allows us to estimate the portion of technically recoverable resources that could be produced economically at various price levels.

The method is based on two statistical hypotheses, both of which have been previously applied to the petroleum industry: sampling from the remaining population of potential drilling sites is assumed to occur without replacement and with probability of selection proportional to the productivity of individual wells. Sampling is without replacement because petroleum resources are finite in nature and subject to depletion. Resources that have been once produced cannot be produced again. Random sampling proportional to productivity reflects the industry's general tendency to drill more productive prospects before less productive prospects.

In addition to accounting for resource depletion, our method also controls for the rapid increase in fracking efficiency that has occurred during the past decade. The potential productivity and relative attractiveness of any given drilling site is determined by physical factors that remain constant through time: total carbon concentration in the underlying shale, plasticity of the rock, thickness of the seam, pressure of the formation, etc. The most desirable sites are endowed with favorable characteristics, which increases the probability they will be selected for drilling. However, the actual productivity of each well that gets drilled also depends on the choice of fracking techniques. Operators have learned through experimentation how production from a given site can be increased by varying the length of the horizontal section, the number of fractures employed, the volume and pressure of water injected into the formation, and the type of proppant used in the procedure. These increases in fracking efficiency tend to mask the impact of resource depletion and therefore play an important role in our estimation procedure.

We illustrate the method by an application to the Bakken shale oil resources located in North Dakota. Since 2006, more than 12,000 horizontal fractured shale oil wells have been drilled there, and those wells constitute our sample data. For each well, we know the date on which drilling began and the recorded initial production rate. Based on the observed sequence of drilling outcomes, we measure the relative frequency of high versus low productivity wells and how it has changed over time—a pattern that reflects the stage of resource depletion. Based on the observed pattern, we estimate the remaining number of potential shale oil drilling sites in North Dakota to be roughly 52,000, which falls in the middle of the range of estimates published by the U.S. Geological Survey and the U.S. Energy Information Administration. We estimate those sites hold 17.0 billion barrels of technically recoverable shale oil, which is very close to EIA's estimate of 16.8 billion barrels but much larger than USGS's estimate of 7.1 billion barrels. All these estimates are based on the assumption that fracking efficiency remains constant at the 2015 level. It is probable that further increases in fracking efficiency will cause the actual volume of technically recoverable resources to exceed these estimates.

The USGS and EIA estimates do not reveal what portion of the remaining technically recoverable resources could be developed economically at various price levels. By accounting for the number of low versus high productivity wells that remain, our approach fills this gap. Still assuming 2015 fracking efficiency, we estimate that roughly half

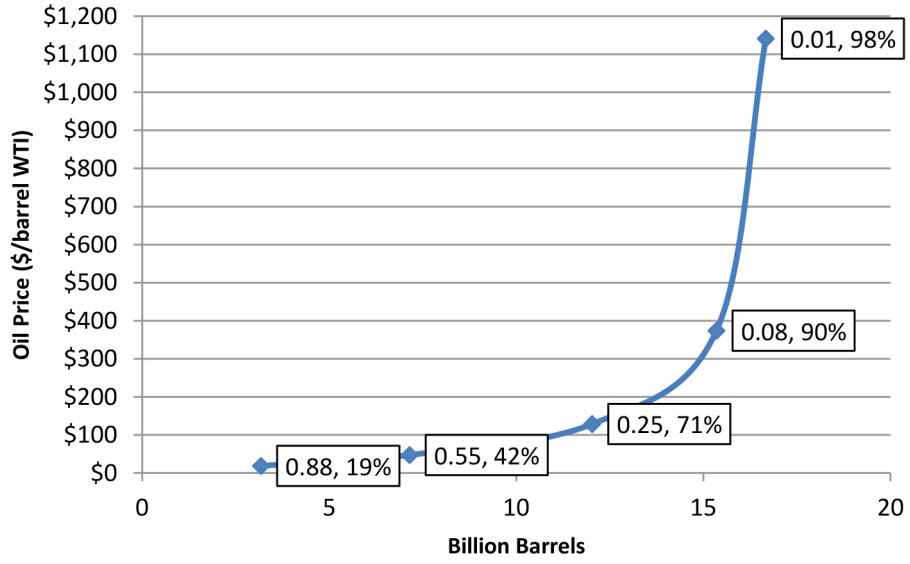


Figure: Volume of Economically Recoverable North Dakota Shale Oil Resources

of the remaining technically recoverable resources would be economic at $50/barrel, and 75% would be economic at $130/barrel. An estimate of the volume of economic reserves as it relates to price—the supply curve of potential reserves—is shown above. A market price of $100/barrel would facilitate development of about 11 billion additional barrels of North Dakota shale oil. Beyond that point, marginal cost rises quickly and the supply curve becomes highly inelastic.

Although our illustration focuses on the Bakken region, the same analysis could be applied to any of the numerous shale oil plays that have emerged recently, and to shale gas plays as well. The Bakken happens to be one of the largest and most productive shale oil plays in the U.S., and is counted on to contribute substantially to future U.S. shale oil output. In addition to demonstrating a new methodological tool, our work therefore makes an important empirical contribution regarding future U.S. shale oil supply.

[1] James L. Smith (2017), "Estimating the Future Supply of Shale Oil: A Bakken Case Study." *CEEPR WP-2017-001*, MIT, January 2017.

Anticipation and Environmental Regulation

by: Katherine Rittenhouse and Matthew Zaragoza-Watkins

Vintage-differentiated emission standards are widely used to regulate pollution from mobile and stationary sources. When a new emission standard is expected to discontinuously change the purchase price or lifetime cost of a new piece of equipment, forward-looking agents may pre-buy equipment, i.e., shift the timing of purchases forward, in order to avoid compliance costs. To investigate the incentives created by vintage-differentiated standards, the impact of those incentives on the new-equipment sales cycle, and the implications for the effectiveness of new-equipment standards, we analyze the market for new Class-8 heavy-duty vehicles (HDVs or trucks). In the context of new-vehicle emissions standards, prior analyses have not considered anticipation as an adjustment margin. In this paper[1], we address four specific questions: How does the anticipation of regulation affect the pattern of new-truck sales? How does the pattern of new-truck sales affect the pattern of used-truck retirements? How do purchasing and retirement patterns affect the environmental benefits of standards? Empirically, have recent regulations caused firms to pre-buy trucks? To answer these questions, we first develop a theoretical model, which incorporates the effects of anticipation on new-vehicle sales and the used-vehicle fleet, and differentiates those impacts from previously identified effects of regulation on the flow and stock of vehicles. We test our predictions using a data set of monthly U.S. sales of new freight trucks around the time of EPA's 2007 implementation of HDV criteria pollutant standards, widely regarded as the most significant action taken by EPA (i.e., with respect to trucks) during the 25-year span of our data. Consistent with our predictions, we find evidence that anticipation caused a sales spike in the months before the policy took effect and a sales slump after implementation. For analysts using time-series variation to study the effects of standards, failing to account for anticipation likely results in significantly biased estimates of the direct effect of the policy on sales. More broadly, our findings have important implications for the analysis of markets in which agents can shift the timing of purchases in anticipation of new regulation.

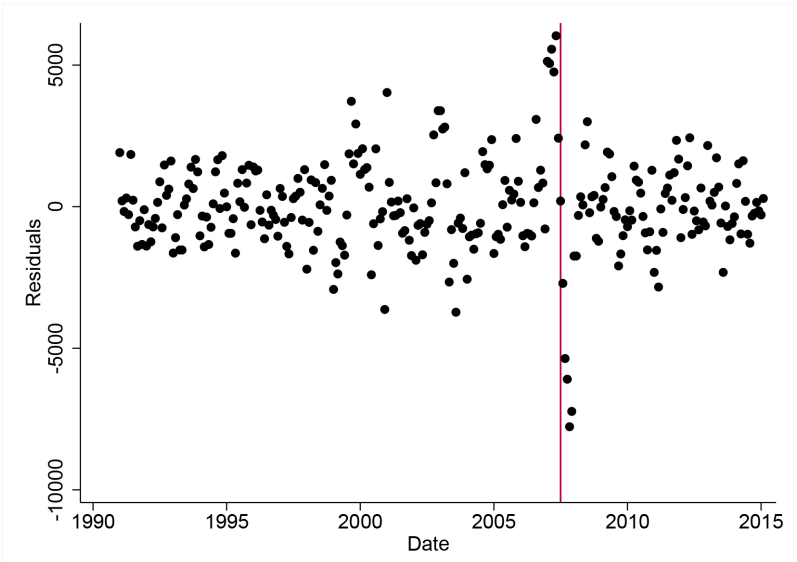
We begin by specifying a dynamic model of a competitive freight truck market, where firms incorporate new-truck prices, operating costs and freight rates (i.e., operating revenue) into their

purchasing and retirement decisions, and calculate comparative statics for changes in upfront and operating costs. We find that an increase in the upfront cost of new trucks causes an increase in the equilibrium freight rate and vehicle lifetime, while an increase in the operating cost of new vehicles causes an increase in the equilibrium freight rate, but has an ambiguous effect on vehicle lifetime. We then analyze how incorporating anticipation (i.e., beliefs about future new-truck prices) affects investment and retirement patterns. We find that, if firms are given the opportunity to buy trucks ahead of costly regulation, they will shift purchases forward, increasing demand for new trucks before regulation is implemented, symmetrically decreasing demand after implementation, and pushing out the oldest (highest-emitting) vehicles in the fleet. The net environmental effect of anticipation depends on how gains from accelerated turnover compare with losses from more-modest emission-rate improvements.

We test our predictions by estimating an econometric model of new-truck sales, using monthly HDV sales in the U.S. over the period 1991-2015. We investigate whether anticipation affected sales by examining residual variation in sales around the month the standards took effect. Consistent with our theory model, we find evidence of anticipation of the 2007 criteria pollutant standards (Figure below). We estimate anticipation of the standards caused several thousand more trucks to be sold in each of the months prior to, and approximately the same number fewer trucks to be sold in each of the months after, the introduction of the standards. Our results are relatively stable across various specifications.

In the United States, the transportation sector is the largest source of criteria pollution, and the second largest source of greenhouse gas (GHG) pollution, regulated under the Clean Air Act.

Figure: Plot of Monthly Sales Residuals



In this figure the y–axis reports the difference between actual monthly Class–8 HDV sales and monthly Class–8 HDV sales predicted by our regression of sales on real oil price, GDP, year and month–of–year fixed effects. The x–axis reports the date. Each (black) dot is a monthly observation. The (red) reference line corresponds to the month the regulation took effect.

Our results have important implications for policy design and program evaluation. Confounding the effects of anticipation with the direct effects of policy would, under a variety of identification strategies, result in significantly biased estimates. Ex ante, policy-makers should account for the effects of anticipation, and minimize the costs associated with it. For example, they may choose to phase in new standards (or award credits for early compliance), eliminating the discontinuous price change which induces a pre-buy. Ex post, analysis that does not account for anticipation risks mischaracterizing the effects of policy. Anticipation is not unique to emissions standards in the HDV industry; similar behavior has recently received increasing attention in the tax avoidance literature. Going forward, it will be important to consider and identify the effects of anticipation across a wide range of policy areas. Whenever regulation is expected to result in a discontinuous change, and agents affected by the regulation are able to adjust the timing of their behavior, we should expect to see some form of anticipation.

[1] Katherine Rittenhouse and Matthew Zaragoza-Watkins (2017), "Anticipation and Environmental Regulation." *CEEPR WP-2017-004*, MIT, February 2017.

Tropical Forests, Tipping Points, and the Social Cost of Deforestation

by: Sergio L. Franklin Jr. and Robert S. Pindyck

The existence of a forest-savanna tipping point implies that changes in forest resilience affect the marginal economic value of a standing forest. The authors propose a new framework for calculating the economic value of a standing tropical forest, and explore the implications of tipping points on the design of optimal land-use policy and payments for ecosystem services.

A number of studies have assessed the economic benefits of a standing tropical forest by estimating the foregone economic benefits resulting from deforestation. The present value of the foregone economic benefits due to one hectare of deforestation has been compared to the present value of future economic benefits of alternative land uses (e.g., crops and cattle ranching) in order to determine the socially optimal land-use policy.

Tropical forest and savanna represent alternative stable states, which are subject to drastic switches at tipping points, in response to changes in rainfall patterns and other drivers. Existing cost studies have ignored the likelihood and possible economic impact of a catastrophic forest-savanna transition, therefore underestimating the social cost of deforestation, favoring the adoption of alternative land uses, and increasing the risk of rainforest collapse.

This paper[1] proposes an alternative framework for calculating the economic value of a standing tropical forest, and explores the implications of a forest-savanna critical transition for the design of optimal land-use policy and payments for ecosystem services. The economic value of a one-hectare grid cell of forest is modeled as a function of a number of hectare-wide (economic and nature) state variables and one ecosystem-wide state variable, forest resilience. The marginal economic value of a standing tropical forest is then measured by the change in total economic value from an additional hectare of deforestation. We applied this framework to the estimation of the social cost of deforestation of the Amazon rainforest.

If it were certain that the worst outcomes from deforestation could be addressed successfully in the future, so that the forest-savanna tipping point would never be reached, then we could rely on current marginal cost calculations that ignore forest resilience. However, if plausible scenarios exist in which the forest ecosystem undergoes a transition, the marginal economic value of a standing forest can be much higher than the present value of the foregone economic benefits from one hectare of deforestation.

We have shown advantages to using an average incremental cost method for the design of optimal land-use policy and payments for ecosystem services. For land-use policy, the increment should be the size of an additional area that is deforested. For the design of payments for ecosystem services, the increment should be the additional deforested area that will bring the entire ecosystem to the forest-savanna tipping point (i.e., a random variable). Additionally, the social cost of deforestation observed by one Amazon country depends on the land-use policies of other countries, and payments for ecosystem services may be necessary to ensure the continued provision of global ecosystem services such as carbon storage and biodiversity protection.

The average incremental social cost of deforestation is a single number that provides relatively long-term guidance for the design of payments for ecosystem services. That number can be used by all Amazon countries, and it is not expected to change much over time, while the marginal social cost of deforestation faced by an individual country may change from year to year.

[1] Sergio Franklin and Robert S. Pindyck (2017), "Tropical Forests, Tipping Points, and the Social Cost of Deforestation." *CEEPR WP-2017-007*, MIT, March 2017.

Are Fuel Economy Standards Regressive?

by: Karen Notsund

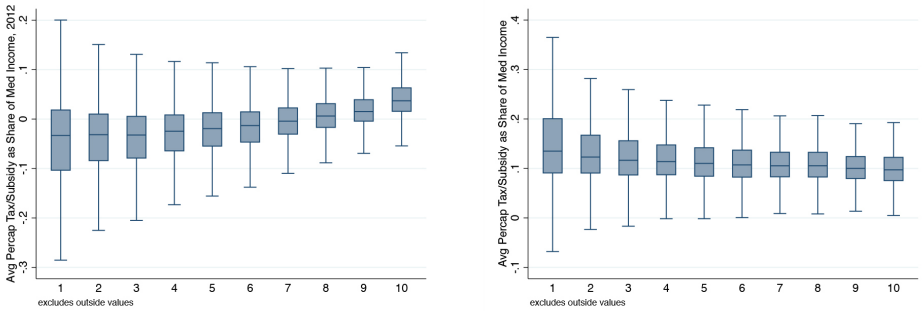
Under CAFE, automakers are required to meet a minimum sales-weighted average fuel economy for their vehicle fleets. Fuel economy standards impose costs, but who bears those costs?

CAFE standards create an implicit subsidy for fuel-efficient vehicles and an implicit tax for fuel-inefficient vehicles. Lucas Davis and Christopher Knittel create a model to determine which U.S. vehicles are most subsidized and most taxed, and then compare the pattern of ownership of these vehicles between high- and low-income households. When the analysis only looks at new vehicles, Davis and Knittel find that CAFE is mildly progressive. High-income households bear more of the cost as a fraction of income than low-income households. This mainly reflects that high-income households buy more new vehicles. When they expand the analysis to include used vehicles, however, fuel economy standards become mildly regressive.

The paper[1] then compares this to a gasoline tax. Although gasoline taxes are often derided as "regressive", the distributional impact of a gasoline tax strongly depends on what is done with the collected revenue. Using existing estimates from the literature, Davis and Knittel show that when revenues are returned uniformly, then a gasoline tax is actually more progressive than fuel economy standards. Thus gasoline taxes are not as "regressive" as commonly believed, nor are fuel economy standards as equitable as some policymakers believe. In the end, the paper concludes that it is difficult to argue for fuel economy standards on the basis of distributional concerns.

This distributional impact is one of the factors that must be considered when comparing standards to alternative policies for reducing carbon dioxide emissions. Economists have long complained that fuel economy standards are an inefficient way to reduce gasoline consumption and prefer a gasoline tax. In a survey of top economists, 90% said that they would prefer a gasoline tax over standards. Fuel economy standards don't achieve the efficient level of vehicle usage, nor do they create efficient incentives for owners to scrap older fuel-inefficient cars, nor do they efficiently distinguish between vehicle models with different average longevities. While there may be political reasons to prefer fuel economy standards, all economic arguments - efficiency and equity - point toward a gas tax.

[1] Lucas W. Davis and Christopher R. Knittel (2016), "Are Fuel Economy Standards Regressive?" *CEEPR WP-2016-016*, MIT, December 2016.



(a) New Vehicles Only (b) New and Used Vehicles

Figure: Average Tax Per Capita as a Share of Median Income, By Income Decile

In this Figure the authors examine the average tax per capita as a share of income. For each census tract the authors know the total tax (or subsidy) paid for all vehicles in the tract, and they divide this by the number of people in the tract, and then by the median income in the tract. The authors report shares as a percentage, so .1 is 0.1% of income. CAFE is progressive when we consider new vehicles only. This upward pattern is more pronounced than when we examined the average tax per vehicle by itself, because high-income households buy more new vehicles. The pattern reverses, however, when we consider both new and used vehicles. The downward pattern shows that the top income deciles bear a smaller average tax than the bottom deciles.

Wind Capacity Investments: Inefficient Drivers and Long-Term Impacts

by: Ian Schneider and Mardavij Roozbehani

Two important criteria for investment in wind capacity are the total energy production and the average market value for energy produced at the wind site under consideration. The tradeoff between these values is important because high-production sites are frequently located near previous wind development, which suppresses local prices and thus the expected energy market value of future production.

Production based subsidies for wind energy, like the federal Production Tax Credit (PTC) and many state Renewable Portfolio Standard (RPS) credits or subsidies, bias investment at the margin towards sites with higher expected capacity values, i.e. with higher total production per unit of site capacity, but with less concern for the correlation between energy output and market prices. Ian Schneider and Mardavij Roozbehani explain how this tradeoff is derived from the optimization problem of a profit-maximizing wind investor, and they derive the impact of the PTC and other energy market policies on the efficient frontier of optimal investments.[1]

The authors also use data from California to indicate the potential effect of the PTC on theoretical investment decisions, detailing how the efficient frontier for investments shifts as a result of the PTC.

Due to the near-zero marginal cost of wind energy production, the availability of wind serves to suppress energy market prices. Ian Schneider and Mardavij Roozbehani use this fact to develop results that link the correlation between a wind project's energy production and energy market prices to the overall variance of system-wide wind energy production. This result shows how production-based subsidies bias investment outcomes in electricity markets towards long-run equilibria with proportionally higher variance of total wind energy output. This particular impact of the PTC is especially relevant because of the greater risk, system reliability costs, and price fluctuations associated with a higher variance of total wind energy output.

The authors explain how existing production-based subsidies for wind energy bias marginal investments to underweight the market value of energy produced, which leads to higher production correlation between developed wind sites and therefore increases system wide variability of wind energy production.

Ian Schneider and Mardavij Roozbehani explore the effects on long-run equilibria of policies that bias investments towards proportionally higher correlation of wind energy outputs. They show that highly correlated wind production supports long-run equilibria with higher capacity served by midrange plants and with less capacity served by peaker and baseload plants, as compared to investment in wind capacity with lower overall output variance. This effect reduces the availability of highly-responsive peaker plants, which could further limit the ability of the system to cope with high variability from wind generation.

Finally, Ian Schneider and Mardavij Roozbehani propose a price-proportional subsidy, where the subsidy received per unit of production varies proportional to the energy market price at the time of production. For instance, a proportional subsidy could always award an additional 20% of the energy market price for each unit of wind energy produced; the specific fraction that determines the subsidy amount can be determined such that program costs are equal to any existing production-based subsidy. Unlike existing production-based subsidies, a price-proportional subsidy scheme does not bias potential investors away from sites with higher average energy value. As such, a price-proportional subsidy would mitigate the effects detailed in this research by which traditional subsidies for wind energy increase the total variance of wind energy from new investments.

[1] Ian Schneider and Mardavij Roozbehani (2017), "Wind Capacity Investments: Inefficient Drivers and Long-Term Impacts." *CEEPR WP-2017-002*, MIT, January 2017.

MITEI Releases *Utility of the Future* Report

by: Emily Dahl

A recent MITEI report calls for regulatory, policy, and market transformation to achieve substantial cost savings for consumers and industry.

Distributed energy resources — relatively small-scale power technologies such as solar, wind, energy storage, and power electronics and control devices — are being deployed rapidly in the global shift toward a low-carbon energy future. To ensure that both distributed and centralized energy resources are integrated efficiently, however, electric power systems in the U.S., Europe, and other parts of the world need major regulatory, policy, and market overhauls, says a new in-depth report, "Utility of the Future," released in December 2016 by the MIT Energy Initiative (MITEI). The report was developed in collaboration with the Institute for Research in Technology at Comillas Pontifical University (IIT-Comillas). IIT-Comillas professor of electrical engineering J. Ignacio Pérez Arriaga, a visiting professor at MIT, and MIT CEEPR Director Christopher R. Knittel, the George P. Shultz Professor of Applied Economics at the MIT Sloan School of Management, served as principal investigators for the study.

Today's electric power systems were designed, built, and regulated well before distributed energy resources — small- and medium-sized technologies that can provide electricity services and are sited in local distribution networks — had come onto the horizon as viable options for widespread use. Now, the businesses and regulatory bodies that determine how power is distributed need a path forward to incorporate these rapidly proliferating technologies. They also need to evolve to meet changing consumer preferences and increase efficiency across the system to achieve cost savings and carbon emissions reductions.

As Pérez Arriaga explains, "the study's two overarching recommendations are to establish a comprehensive system of prices and regulated charges that applies to all network users, and to remove inefficient barriers that impede the integration and competition of both distributed resources and centralized resources, such as power sector structures that prevent fair competition and wholesale electricity market design flaws. Our framework of recommended proactive reforms can enable the efficient evolution of electric power systems into the next decade and beyond."

Among the study's recommendations is a set of measures to improve tariff and

rate structures for electricity services. For example, electricity services should be priced in a "technology-agnostic" manner that is based solely on how consumers use these services. Making use of "peak-coincident capacity charges," which increase prices when electricity networks are under stress or generating capacity is scarce, can discourage consumers from drawing on the grid during these times. Prices and charges should also better reflect how the value of services changes at different times of day or at different locations in the grid. Such cost-reflective pricing can open up opportunities for distributed resources — many of which already exist but are not responding to current economic signals — and enable significant cost savings.

Another finding is that for technologies such as solar photovoltaics and energy storage, which can be connected at different voltage levels and various sizes, understanding tradeoffs between locational value and incremental unit costs due to economies of unit scale can help planners identify the ideal locations and applications for these resources.

"We often focus on breakthroughs and innovation at the cutting edge of energy technology. But being mindful of the economics of these new resources is absolutely essential: sometimes the most exciting technological solutions will not be economically viable", Knittel explains, highlighting the importance of robust economic analysis which contributed to the study.

Additional recommendations include improvements to the way distribution network companies are compensated and incentivized to incorporate distributed resources efficiently, re-evaluation of the structure of the electricity industry to allow the creation of new business models, and implementation of robust cybersecurity standards for interconnected energy resources and appliances. Improvements to wholesale market design could also better integrate distributed resources and reward greater flexibility while creating a level playing field for all technologies.

The report emphasizes the urgency of proactive reforms. Electricity users now face unprecedented choices regarding how they get their power and manage their electricity consumption; they need improved economic signals — prices, charges, and other economic incentives — in the near term to guide these decisions.

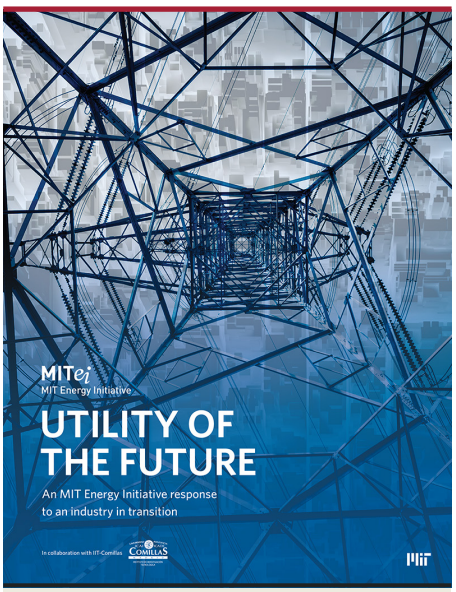
"The risk of continuing business as usual is immense in terms of system reliability and costs associated with inefficiencies — which many stakeholders in the electric power sector recognize and want to avoid," adds Pérez-Arriaga.

"This report is the result of a multiyear, comprehensive, and rigorous research study in which authors conducted extensive primary research, including data gathering and modeling, and interviews with regulators and business leaders in the electric power sector — including the study consortium members," says the study's executive director, Raanan Miller of MITEI. Adds Robert C. Armstrong, MITEI's director and the Chevron Professor in Chemical Engineering at MIT: "Our study does not try to predict the future or prescribe which technologies should prevail; instead, it provides a toolkit for businesses, policymakers, and regulators to navigate the unfolding changes in the system and develop a more robust, efficient system for the future."

Research and findings from the "Utility of the Future" study will inform research taking place through MITEI's new Low-Carbon Energy Center for Electric Power Systems, one of eight MITEI low-carbon energy centers, each of which focuses on advancing key technology areas for addressing climate change. MIT CEEPR will remain engaged in the process, drawing on its theoretical and methodological strengths in energy policy and economics to enrich the work of the low-carbon energy centers.

This report is the first in a new series of MIT consortium research studies focused at the system level and intended to inform industry stakeholders and regulators. The other report currently under way in this new series is the "Mobility of the Future" study on the evolution of the transportation sector. The consortium members of "Utility of the Future" are a diverse set of leading international companies with expertise in various aspects of electric power services and technologies. Members provided support, gave regular feedback, shared insights in a series of workshops, and participated in the external advisory committee. Like MITEI's "Future of" studies, "Utility of the Future" is written by a multidisciplinary team of MIT researchers, whose research was informed by a faculty advisory committee.

"Being mindful of the economics of these new resources is absolutely essential."
— Christopher R. Knittel, Director, MIT CEEPR



The full *MIT Utility of the Future Report* is available online at the MIT Energy Initiative webpage: http://energy.mit.edu/research/utility-future-study/

Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Consequences and Policy Options

by: Geoffrey Haratyk

U.S. nuclear reactors have been retiring at an unprecedented pace for the last few years. Tens of gigawatts of zero-emission nuclear capacity are now at risk of retiring prematurely.

Power prices have fallen significantly since 2008, putting commercial nuclear reactors in the United States under substantial financial pressure. These low prices, mostly caused by negative demand growth and cheap natural gas, are expected to persist. Nuclear power plants, accounting for 60% of the carbon-free electricity generated in the country, are retiring or are at risk of retiring before the end of their operating license, despite positive operational records. In the past three years, five nuclear power plants, totaling 4.7 GW of installed capacity, retired from the electrical grid, and eight additional ones have officially announced their retirement in the coming years.

This paper[1] aims to analyze nuclear power plant closures. Although the literature on new nuclear power plant economics and climate benefits is abundant (Joskow and Parsons, 2009), few studies have focused on the prospects for existing reactors. Davis and Hausman (2016) quantified the consequences of the recent closure of the San Onofre Nuclear Generating Station in California using econometric techniques. Here, we provide a detailed valuation of every U.S. reactor. We employ our own wholesale electricity market model to study the mechanics and outcome of market changes. Finally, we re-examine the supposed contradiction between competitive markets and high-level policy objectives, in light of nuclear retirements. Are regulatory changes needed and justified for nuclear to survive in free competitive markets? What are the options offered to policymakers?

Our study shows that nearly two-thirds of the 100 GW nuclear capacity are uncompetitive in the U.S. over the next few years under the current price trajectory (see figure). Among those in merchant deregulated market environments, 21 GW are retiring, or are at high risk of retiring prematurely. Nuclear reactors mostly suffer from a revenue problem. Wholesale electricity prices have fallen by 40 to 50% between 2008 and 2015, and neither trends in capacity prices nor nuclear production costs have been able to stop the decline in nuclear profitability.

The potential consequences of a massive nuclear capacity withdrawal depend on the future energy mix. If 30 GW were to be replaced by modern gas-fired combined cycle plants, U.S. gas burn and carbon emissions from the power sector would rise by an estimated 5.2% and 4.9% respectively. Electricity supply would rely even more heavily on natural gas. If replaced by renewables (wind), the withdrawal would be carbon-neutral, but the cost would be greater in most locations.

In a context of uncertainty around future fuel prices, technological progress, and climate policy, avoiding the irreversible

shutdown of nuclear assets is deemed preferable. This would minimize cost as well as damage to the environment while ensuring long-term security of supply.

To maintain nuclear power, policymakers could employ several regulatory instruments in deregulated markets. Carbon pricing is a prefered measure that would reconcile climate objectives with competitive markets and benefit nuclear energy. Calculations show that a carbon price as low as \$10 / MT CO_2 would be sufficient to maintain most U.S. nuclear capacity. Without a carbon price, out-of-the-market payments would be needed to effectively maintain nuclear capacity, though they would create market distortions. Filling the revenue gap would come at a cost of \$4-7/ MWh on average in deregulated markets, which is much lower than the cost of subsidizing equivalent wind power, or the social cost of carbon damage caused by equivalent new gas-fired generation. Policy support could take the form of direct zero-emission credits, renewable portfolio standard expansion, or "clean" capacity market mechanisms. As a last resort, the exercise of a new mothballing status could prevent the premature retirement of the most at-risk nuclear plants.

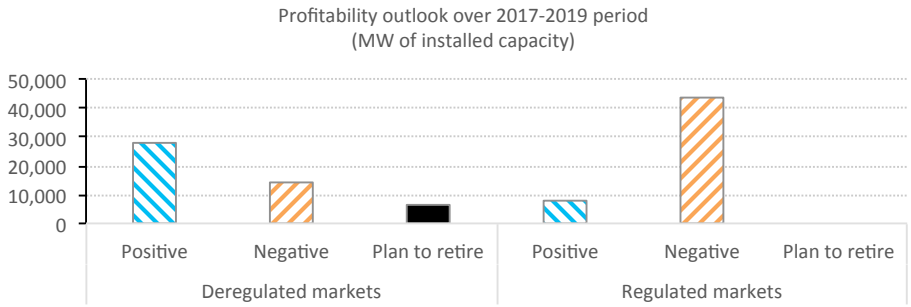


Figure: The majority of the 100 GW nuclear fleet is unprofitable or retiring in the near future. In deregulated markets, 43% of the merchant capacity is on a path to retirement. The plants in regulated environments are to a large extent protected from market forces. Note that recently-voted-on state subsidies are included in the calculation.

[1] Geoffrey Haratyk (2017), "Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Consequences and Policy Options." *CEEPR WP-2017-009*, MIT, March 2017.

A Green Bargain? Impacts of an Energy Saving Program on China's Iron and Steel Industry

by: Thomas Geissmann and Valerie Karplus

To improve the energy efficiency of China's rapidly-growing industrial sector, China's central government launched the national Top-1000 Energy-Consuming Enterprises Program (T1000P) during the Eleventh Five-Year Plan (FYP) (2006-2010). At that time, the T1000P was the most ambitious effort ever made in China in terms of its coverage of energy-intensive firms and state resources allocated to reduce industrial energy use. It was designed to support a national goal of reducing energy intensity by 20% nationwide during the Eleventh FYP. The program targeted about 1000 of the country's most energy demanding firms, i.e. the firms consuming a minimum of 180,000 tons of coal equivalent in 2004 (Price, Wang et al., 2010). Due to its high energy consumption, the highest share of firms targeted by this regulation belonged to the iron and steel industry.

In this paper[1], we study the impact of the T1000P on the total factor productivity (TFP) growth of iron and steel firms included in the program. TFP growth is a measure of the efficiency with which firms turn inputs into outputs. It is critical for maintaining international competitiveness and sustaining high long-term growth rates. Finally, it represents a foundation of social welfare and living standards (Greenstone, List et al., 2012; Krugman, 1997).

Previous literature has found that firm productivity is adversely affected by environment regulations (Gollop and Roberts, 1983; Gray and Shadbegian, 2003; Greenstone, List et al., 2012). We measure the impact of the program in China and find the opposite: that firms included in the program experienced greater productivity growth that those not included. The benchmark specification finds the regulation positively affected TFP change in treated firms by 3.1% on average between 2006 and 2008. Technical change and scale efficiency change contributed about equally to this overall effect. Observed positive effects are robust to alternative methods of constructing a comparison group, and instrumenting for selection into the program. The average economic benefit of the program to each treated firm is estimated to be 148.7 million Chinese renminbi in 1998 values, before accounting for the economic value of any improvements in environmental

The authors study the impact of a large-scale national energy saving program in China on firm productivity in the iron and steel industry.

Spatial distribution of the firms in the complete sample

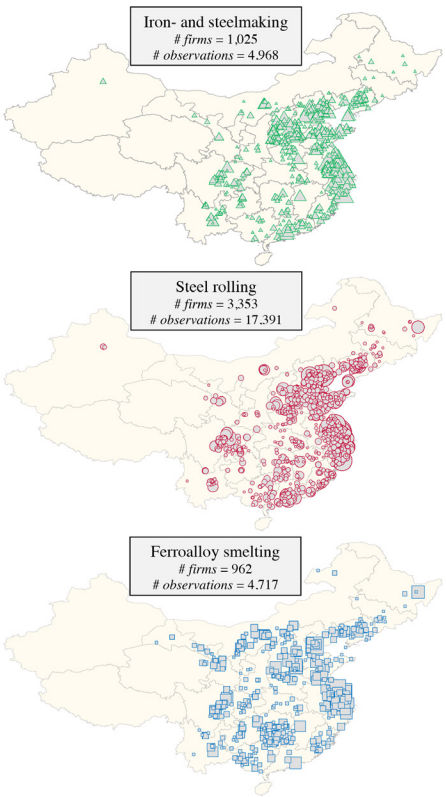


Figure: Spatial distribution of the sample firms by subindustry in 2005. Marker size is relative to the number of firms observed in a county.

integrity.

The positive effect of the policy on productivity growth is noteworthy as it differs from findings of negative effects in prior studies of developed countries. We suggest at least two reasons for this finding. First, firms involved in the T1000P were able to access subsides to improve the efficiency of their facilities, transfering a large share of compliance costs to the state. Second, the policy may have focused firm energy and effort on low hanging fruits related to energy saving that delivered benefits in the form of operational efficiencies and reduced costs.

Several features of this study stand out. First, it is one of only a few studies to estimate TFP change using a cost function approach. Second, to our knowledge, this is the first study of its kind for China. Third, our specification enables us to distinguish between the subcomponents of technical change and scale efficiency change using parametric methods. Such decomposition allows for a more detailed analysis of the effects of the regulation than what has been common practice in the literature. Fourth, we include muliple robustness checks to address concerns about selection bias and time-varying potentially cofounding factors. Fifth, the study uses a uniquely detailed firm-level data set. Detailed information from the Chinese Industrial Census was used to construct an unbalanced panel of 20,076 unique observations of 5,340 firms over the period 2003 to 2008. Effects of the T1000P on TFP change are analyzed by applying a difference-in-difference research design.

Our results are robust to alternative empirical strategies. We control for temporal, spatial, sub-industry and firm-specific heterogeneity when assessing the impact of the regulation on productivity. Results are robust when stratifying the sample along several dimensions, when accounting for sample attrition, when instrumenting for T1000P exposure and when accounting for a potentially confounding regulation that required closure of certain small, inefficient iron and steel producers over the same period.

[1] M. Filippini, T. Geissmann, V. Karplus and D. Zhang (2017), "A Green Bargain? The Impact of an Energy Saving Program on Productivity Growth in China's Iron and Steel Industry." *CEEPR WP-2017-005*, MIT, March 2017.

CEEPR Postdoctoral Fellow: Ignacia Mercadal

Ignacia Mercadal is visiting MIT during the 2016-17 academic year, as a postdoctoral fellow at CEEPR and the MIT Sloan School of Management. As an economist interested in industrial organization and energy economics, her research focuses on competition in energy markets.

Mercadal obtained her Ph.D. in Economics from the University of Chicago in 2016, and will join the faculty of the School of International and Public Affairs at Columbia University in July 2017.

In ongoing research, Mercadal is interested in the role of vertical relationships in deregulated electricity markets in the United States. Deregulation created separate markets for generation, transmission, and distribution, but allows the same firm to be active in multiple segments. Additionally, firms may sign long-term contracts, increasing the degree of market integration. After finding cases in which prices went up after deregulation, relative to the relevant benchmark, this project uses variation in deregulation rules across states in order to determine how to effectively introduce competition into deregulated markets.

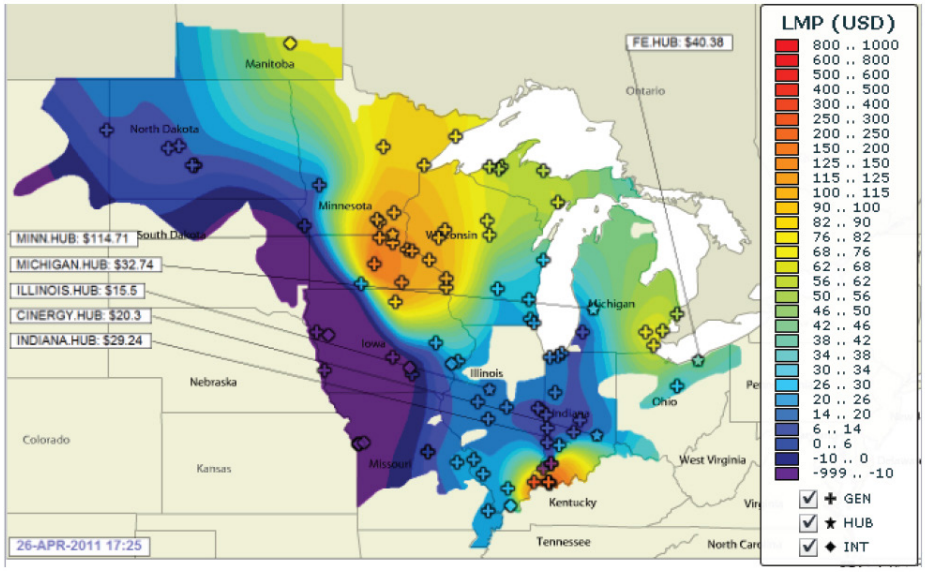
Dr. Ignacia Mercadal is a CEEPR Postdoctoral Fellow at the MIT Sloan School of Management focusing on the role of financial traders in deregulated U.S. wholesale electricity markets.

In recent research, Mercadal has examined the role of financial traders in deregulated wholesale electricity markets. Though financial speculators are allowed in commodity markets because they are expected to contribute to market efficiency and provide liquidity, there is a common perception that they are harmful to consumers. This may lead to artificially high prices or speculators engaging in market manipulation. This controversy motivates Mercadal's research, since electricity markets provide a unique setting to investigate the effects of financial traders on consumer welfare and market efficiency. Unlike other commodity markets, physical and financial traders interact in the same market, which allows us to study the consequences of their activity on the price of the physical good, electricity, as well as on producers' and consumers' welfare. Additionally, data availability in deregulated electricity markets makes it possible for researchers to observe the strategies and returns of every player — physical or financial.

Exploiting these unique features of electricity markets, particularly in the case of the American Midwest, Mercadal has looked at the effect of increased financial activity on producers' behavior. Her research shows financial traders can lead to lower prices and higher consumer welfare by acting as de facto competitors of physical producers. Because, so far, electricity is not stored, and supply needs to meet demand at every moment, generators typically have market power (i.e. generators can affect prices as opposed to being price-takers under perfect competition). When producers exert market power, they create price differences between the scheduling 'day-ahead' market and the balancing 'real-time' market. Financial traders make profits by arbitraging these price differences, effectively reducing the generators' market power and benefiting consumers.

The positive consequences from financial traders in electricity markets are not guaranteed to be achieved. In a second paper on the role of financial traders that is included in the CEEPR Working Paper series, Mercadal and her co-authors John Birge, Ali Hortaçsu, and Michael Pavlin explore the limits to financial arbitrage by examining the case of the Midwest market. Their findings indicate that competition among financial traders is important to

Electricity Price Heat Map



Source: https://www.misoenergy.org

Figure: Prices differ across locations because the limited capacity of the transmission lines does not always allow the transport of energy from the cheapest producer to where it is demanded. FTRs are financial instruments designed to allow market participants to hedge the risk from local price differences.

achieve the efficiency gains they are expected to bring, and that restricting their activity may make market manipulation easier and more likely than under competitive conditions.

The limited capacity of transmission lines does not always allow the transport of electricity from the cheapest producer to where it is demanded. To account for this, most deregulated electricity markets in the U.S. use nodal pricing, which means prices are allowed to vary across locations to reflect scarcity. This poses a challenge for researchers studying firms' strategic behavior, since the price at which a firm can sell will depend on the set of competitors it faces, which in turn depends on the available capacity of transmission lines. As this is not observed, Mercadal deals with this challenge using machine learning tools to define the market in which each firm competes.

Limits to Arbitrage in Electricity Markets: A Case Study of MISO

by: Ignacia Mercadal

Though financial players in commodity markets are expected to improve market performance, manipulation scandals and higher prices attributed to their trading have made their role controversial and lead to proposals to restrict their activity. This paper[1] studies the case of the Midwest electricity market, which allows the participation of purely financial firms like most North American deregulated markets.

Electricity generation is cheaper when it is planned, because supply needs to continuously meet a stochastic demand and adjusting production levels is costly. For this reason, most electricity markets are organized as sequential markets: There is, first, a forward market that schedules production a day in advance, and then a spot market to adjust for unexpected shocks right before operation. The market is more efficient when the forward and spot prices are on average similar, sending accurate signals for generation planning. Nonetheless, a forward premium has been documented in several markets around the world, i.e. the forward price is, on average, higher than the spot price.

Financial or virtual players have been introduced to arbitrage this forward premium. Firms buy or sell in the forward market, and then their transaction is reversed in the spot market, i.e. buying 1MWh in the forward market requires to sell it in the spot market. Saravia (2003) and Jha and Wolak (2013) have shown that after financial players were introduced in New York and California, respectively, the forward premium decreased, as did production costs and emissions. By contrast, the forward price in the Midwest was consistently higher than the spot price in 2010, despite the presence of financial traders since the market opened in 2005.

The first part of the paper investigates whether financial traders have an effect on the premium. Because a larger premium attracts more financial traders, this effect cannot be determined by just looking at the correlation between financial transactions and the premium. Instead, we use two variables that affected the volume of financial transactions, but are unlikely to be

Like in other deregulated markets, financial players were introduced to the Midwest electricity market to arbitrage price differences that distort planning decisions. Unlike other markets, this did not seem to be working.

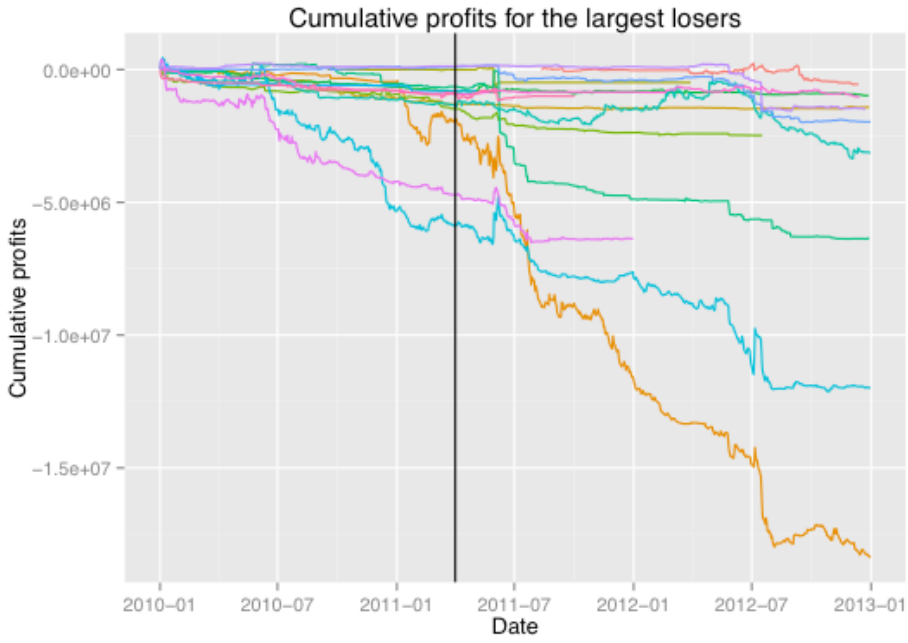
related to the premium, in order to isolate the effect. The first is a measure of perceived financial risk that increased during the financial crisis, and the second is a regulatory change that imposed large transaction costs on financial traders.

We find that financial traders seem to contribute to a lower forward premium, but the effect is not robust. A deeper exploration of virtual bidders' behavior indicates that some players were not acting as expected. In spite of the forward premium, there were more virtual purchases than sales in the forward market. As these transactions entail buying at the forward price and selling at the spot price, they bet on the wrong direction and we would expect them to yield negative profits. In fact, some traders consistently lost money over time without leaving the market. This can be observed in the adjacent figure, which depicts the profits of the ten largest losers.

The surprising behavior of some traders can be rationalized once we consider the closely related market for financial transmission rights (FTRs) — financial instruments that pay based on local price differences in the forward market. Prices differ across locations because limited transmission does not always allow bringing electricity to where it is demanded. FTRs allow firms to bet on local price differences, either to arbitrage or to hedge. Virtual demand bids can be used to increase the value of FTRs: By increasing demand at a given location, prices will raise when there is not enough transmission capacity to bring enough energy to cover demand. The difference between local prices will increase, as will the FTR's payoff, even after considering the losses from virtual purchases in the presence of a forward premium.

Consistent with this hypothesis, we find that virtual bids and FTRs are correlated. Moreover, evidence is consistent with market manipulation only during the period in which the regulator imposed high transaction costs on financial participants. These charges restricted competition between traders, making manipulation possible. Our findings point out the importance of competition between financial traders, as opposed to restricting their participation, as a means to avoid manipulation and increase market efficiency.

[1] J. Birge, A. Hortaçsu, I. Mercadal, and M. Pavlin (2017), "Limits to Arbitrage in Electricity Markets: A case study of MISO." *CEEPR WP-2017-003*, MIT, January 2017.



The cumulative profits of some of the ten largest virtual losers among virtual bidders consistently decreased, indicating that some players stayed in the market despite having steady losses. This is not consistent with profit maximization by pure speculators, especially considering that they are experienced bidders in a complex market.

2016 Fall Research Workshop

by: Michael Mehling

MIT Professor Jacopo Buongiorno speaks to over 80 attendees during a session on nuclear power at the 2016 Fall CEEPR Research Workshop.

As in every fall, the MIT Center for Energy and Environmental Policy Research (MIT CEEPR) convened a diverse audience of faculty and researchers, public policy makers and private sector representatives for its 2016 Fall Research Workshop, held in Cambridge, Mass., on November 17-18, 2016. 80 participants attended the workshop for a lively discussion of relevant issues in the broader energy and environmental policy arena.

Evolving markets for oil and gas were the focus of two sessions during the first workshop day, with presentations by MIT's Sergey Paltsev and John Parsons, James Smith of SMU, and Lutz Kilian of the University of Michigan. Among other themes, their remarks reflected on the impacts of U.S. unconventional oil and gas production on international markets, uncertainty regarding the causes and effects of the recent decline in oil prices, and improved understanding of the costs of hydrocarbon production by disaggregating capital expenses and operational expenses, including exploration, development and lifting cost as well as fiscal and concession charges.

Mauricio Tolmasquim, the former head of the Brazilian Energy Research Institute, and Sergio Franklin, a Visiting Scholar joining CEEPR from the Brazilian Private Insurance Regulator (SUSEP), shared insights into the climate and energy policies of Brazil, an emerging economy undergoing major political and socioeconomic transformation. One research project described during the session, led by Franklin together with MIT's Robert Pindyck, proposes an alternative approach to capturing the marginal social cost of tropical deforestation by better integrating new knowledge on the complex and non-linear interactions in forest ecosystems.

Rounding off the first day, CEEPR Director Christopher Knittel and CEEPR Visiting Scholar Thomas Brewer of the International Centre for Trade and Sustainable Development (ICTSD) turned their focus to transportation, with presentations on the regressive nature of fuel economy standards and options to curb particulate emissions – 'black carbon' – from international shipping. A keynote presentation during dinner by Michael Grubb of University College London highlighted recent trends in energy and climate policy in the United Kingdom.

MIT's Jacopo Buongiorno and Charles Rossman of Southern Company opened the second workshop day with a session focused on the prospects of nuclear power. With a common departure point – the importance of nuclear power in a low-carbon economy, especially as additional sectors such as transportation become electrified – they highlighted growth opportunities for nuclear and the role of emerging nuclear technologies, and discussed regulatory and financial obstacles currently preventing an improved economic outlook for the nuclear sector.

Finally, a panel discussion with Mary Ellen Paravalos of National Grid, Bill White of the Massachusetts Clean Energy Center, and MIT's Jesse Jenkins drew attention to offshore wind energy and its potential in the New England region, including the impact of recent energy legislation in the state of Massachusetts that sets the most ambitious offshore wind mandate in the country. Themes touched upon during the discussion were the role of energy storage policies, the importance of stakeholder engagement and social acceptance, ways to comply with regulatory and licensing requirements, and ancillary benefits such as local energy security, spurring new industry and employment growth, and reducing carbon emissions.

UPCOMING WORKSHOPS

July 6-7 2017, Paris, France
November 16-17, 2017, Cambridge, MA

Notable Changes

Dr. Marcus Müller

In January, CEEPR welcomed **Dr. Marcus Müller** of the Technical University Munich in Germany as a Visiting Scholar. His research focuses on battery cell chemistry and energy storage systems. During his visit to MIT, Marcus will focus his research on the impacts of energy policy on electricity markets in the U.S., Germany, and the EU, and evaluating differences in the energy policies governing the integration of renewable energy in the U.S. and EU.

In addition, in February, **Dr. Erik Lundin** of the Research Institute of Industrial Economics in Sweden began his stay at CEEPR as a Visiting Postdoc. Erik is an expert on empirical industrial organization, electricity restructuring, and energy economics. While at CEEPR, Erik will mainly work on a project entitled "Measuring Market Power in Bid-based Electricity Markets". The work develops a new empirical method to measure the exercise of market power in electricity wholesale markets.

Dr. Erik Lundin

Recent Working Papers

WP-2017-009
Early Nuclear Retirements in Deregulated U.S. Markets: Causes, Consequences and Policy Options
Geoffrey Haratyk, March 2017

WP-2017-008
Are Consumers Poorly-Informed about Fuel Economy? Evidence from Two Experiments
Hunt Allcott and Christopher R. Knittel, March 2017

WP-2017-007
Tropical Forests, Tipping Points, and the Social Cost of Deforestation
Sergio L. Franklin Jr. and Robert S. Pindyck, March 2017

WP-2017-006
When Do States Disrupt Industries? Electric Cars in Germany and the United States
Jonas Meckling and Jonas Nahm, March 2017

WP-2017-005
A Green Bargain? The Impact of an Energy Saving Program on Productivity Growth in China's Iron and Steel Industry
Massimo Filippini, Thomas Geissmann, Valerie J. Karplus, and Da Zhang, March 2017

WP-2017-004
Anticipation and Environmental Regulation
Katherine Rittenhouse and Matthew Zaragoza-Watkins, February 2017

WP-2017-003
Limits to Arbitrage in Electricity Markets: A Case Study of MISO
John Birge, Ali Hortaçsu, Ignacia Mercadal, and Michael Pavlin, January 2017

WP-2017-002
Wind Capacity Investments: Inefficient Drivers and Long-Term Impacts
Ian Schneider and Mardavij Roozbehani, January 2017

WP-2017-001
Estimating the Future Supply of Shale Oil: A Bakken Case Study
James L. Smith, January 2017

WP-2016-016
Are Fuel Economy Standards Regressive?
Lucas W. Davis and Christopher R. Knittel, December 2016

WP-2016-015
Running Randomized Field Experiments for Energy Efficiency Programs: A Practicioner's Guide
Raina Gandhi, Christopher R. Knittel, Paula Pedro, and Catherine Wolfram, July 2016

All listed and referenced working papers in this newsletter are available on our website at ceepr.mit.edu/publications/working-papers

MIT CEEPR

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A panel discussion focusing on the implications of the oil price decline during the 2016 Fall CEEPR Workshop in Cambridge, MA on November 17, 2016.