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Editorial.

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With a partial recovery from the COVID-19 pandemic marred by energy price spikes, supply chain disruptions, extreme weather events, geopolitical tensions, and profuse – although not always well-considered – policy developments, the year that just came to an end may not instill great optimism about prospects for 2022. Indeed, some trends that defined energy and environmental policy in 2021 will undoubtedly also shape the year ahead. Factors that contributed to surging energy prices will be difficult to reverse in the near term, such as years of stagnating investment in conventional energy resource discovery and exploration. Similarly, abnormal weather patterns – which have caused or exacerbated supply constraints through depleted hydropower reservoirs, diminished wind energy output, or generator and refinery outages – defy straightforward solutions. Decisions taken now, for instance to improve the resilience of energy infrastructure, will take time to implement and yield results.

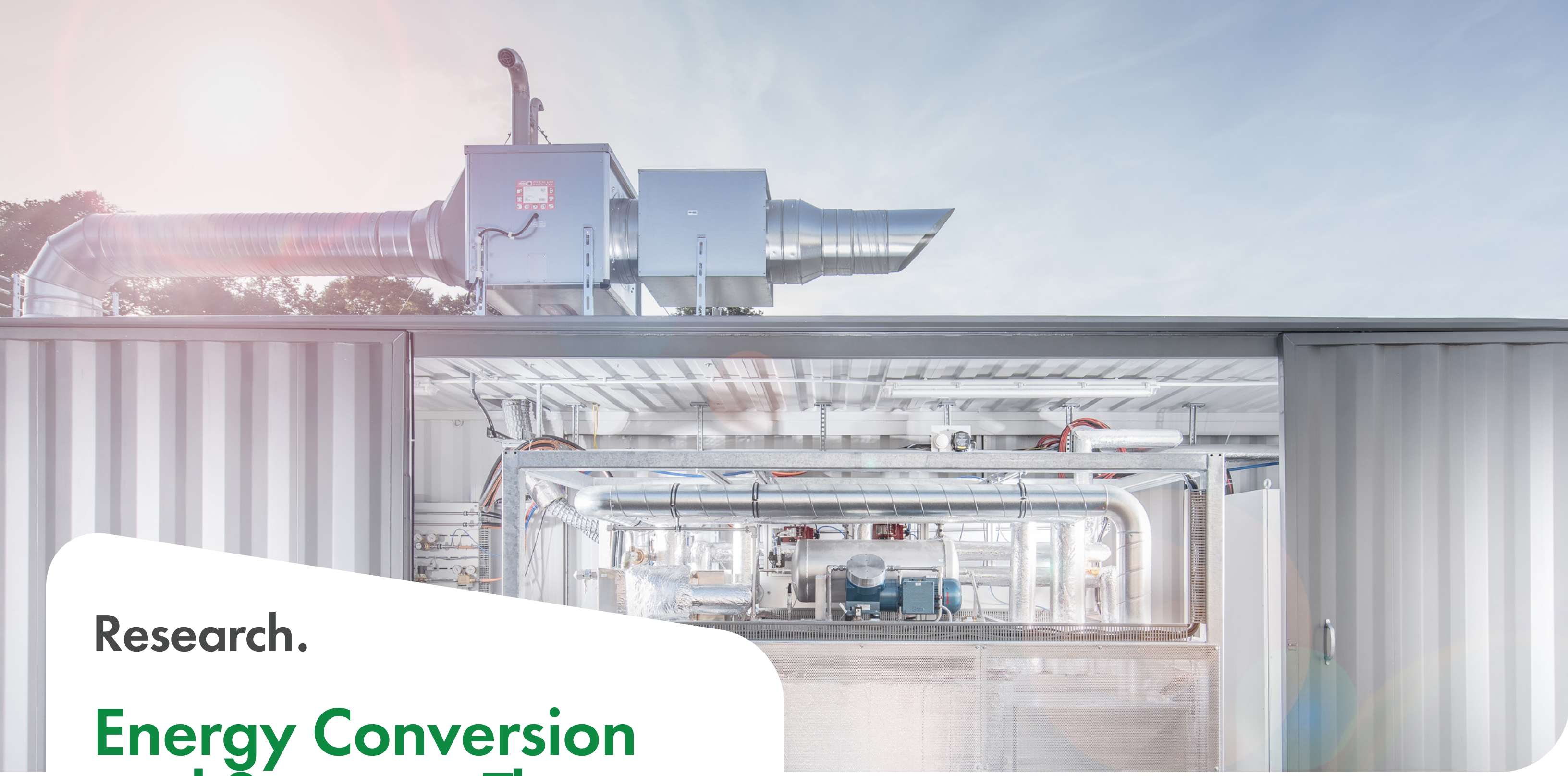
While supply chain disruptions owed to the global COVID-19 pandemic are expected to subside, geopolitical tensions triggered by trade conflicts and security concerns can continue to spill over into energy markets, creating regional uncertainty about the availability of energy as well as critical technology components and raw materials. 2021 was also a forceful reminder that politics remains the ultimate contingency, with continuous setbacks to the 'Build Back Better' agenda casting a pall over the future direction of federal climate policy, and hasty policy interventions to contain energy price spikes in European countries raising questions about the market liberalization course charted in Brussels. In all the unpredictability, however, the year-end climate summit in Glasgow overcame substantial obstacles to affirm – at least in principle – multilateral commitment to an accelerating energy transition.

Tempting as it may be to speculate about what the future holds for energy and environmental policy, however, MIT CEEPR will instead continue to rely on empirical data and established methodologies to understand the most pressing challenges we currently face. As the research highlights summarized in this newsletter underscore, doing so does not rule out working on topics of great timeliness, from market design for rapidly evolving electricity systems and uses of new and conventional nuclear technology to storage and transmission expansion needs, vehicle fleet electrification, and international climate negotiations. Working together with our partners, we will continue to offer relevant insights for decision makers in what will – and this is a prediction that requires little speculation – almost certainly remain turbulent times ahead.

Michael Mehling

Contents.

![Research.]



Research.

Energy Conversion and Storage: The Value of Reversible Power-to-Gas Systems.

By: Gunther Glenk and Stefan Reichelstein

The large-scale deployment of intermittent energy resources, like wind and solar, has generally resulted in deregulated power markets becoming more volatile (Olauson et al., 2016; Davis et al., 2018). To balance supply and demand for electricity in real time, energy storage in the form of batteries or pumped hydro power is playing an increasingly important role. At the same time, hydrogen is increasingly viewed as an energy carrier with broad application potential in decarbonized energy economies (De Luna et al., 2019; Staffell et al., 2019).

Power-to-Gas (PtG) systems that split water molecules into hydrogen and oxygen via electrolysis can rapidly absorb surplus electricity during times of low prices (Shaner et al., 2016; Van Vuuren et al., 2018). This buffering capacity of PtG systems can be enhanced further by systems that are also capable of operating in the reverse direction, converting hydrogen to electricity during periods of limited power supply and accordingly high power prices (Albertus, Manser and Litzelman, 2020).

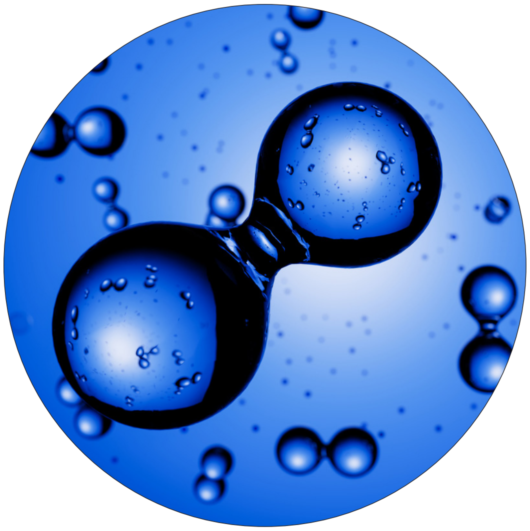
Reversible PtG systems can be designed in a modular manner, for instance by combining a one-directional electrolyzer for hydrogen production with a one-directional fuel cell or gas turbine for power generation (Guerra et al., 2020; Uniper SE, 2020). While electrolyzers have been found to become increasingly competitive in producing hydrogen (Guerra et al., 2019), fuel cells and gas turbines have so far been regarded as too expensive for producing electric power sold in wholesale markets (IEA, 2019).

Alternatively, solid oxide fuel cells constitute integrated PtG systems, as the same equipment can be utilized to deliver either hydrogen or electricity depending on the state of electricity prices at any given point in time. Solid oxide cells have been brought to market recently and their reversibility feature has been established in several studies and demonstration projects (elcogen, 2018; Regmi et al., 2020).

This paper first presents a novel analytical model examining the economic viability of reversible PtG systems. We then calibrate the model in the context of the electricity markets in Germany and Texas. Despite improvements in the cost and conversion efficiency of modular PtG systems, we confirm the findings of earlier studies that there is no economic case, either now or in the foreseeable future, for investing in modular systems that convert hydrogen back to electricity.

In contrast, we find that integrated PtG systems are competitive at current hydrogen prices, given sufficient variation in daily electricity prices, as is already encountered in the Texas market. While it is efficient for such systems to mostly produce hydrogen, they can also respond to high power prices with additional electricity supply. Due to this improved capacity utilization, integrated systems are positioned more competitively than one-directional electrolyzers on their own.

Finally, if recent trends regarding the acquisition cost of solid oxide cells continue, such systems will remain economically viable even with substantially lower hydrogen prices in the future. The reason is that the inherent flexibility of integrated reversible PtG systems allows them to respond to lower hydrogen prices by engaging more frequently in power generation.



Gunther Glenk and Stefan Reichelstein (2021), "Energy Conversion and Storage: The Value of Reversible Power-to-Gas Systems", CEEPR WP-2021-007, MIT, May 2021.

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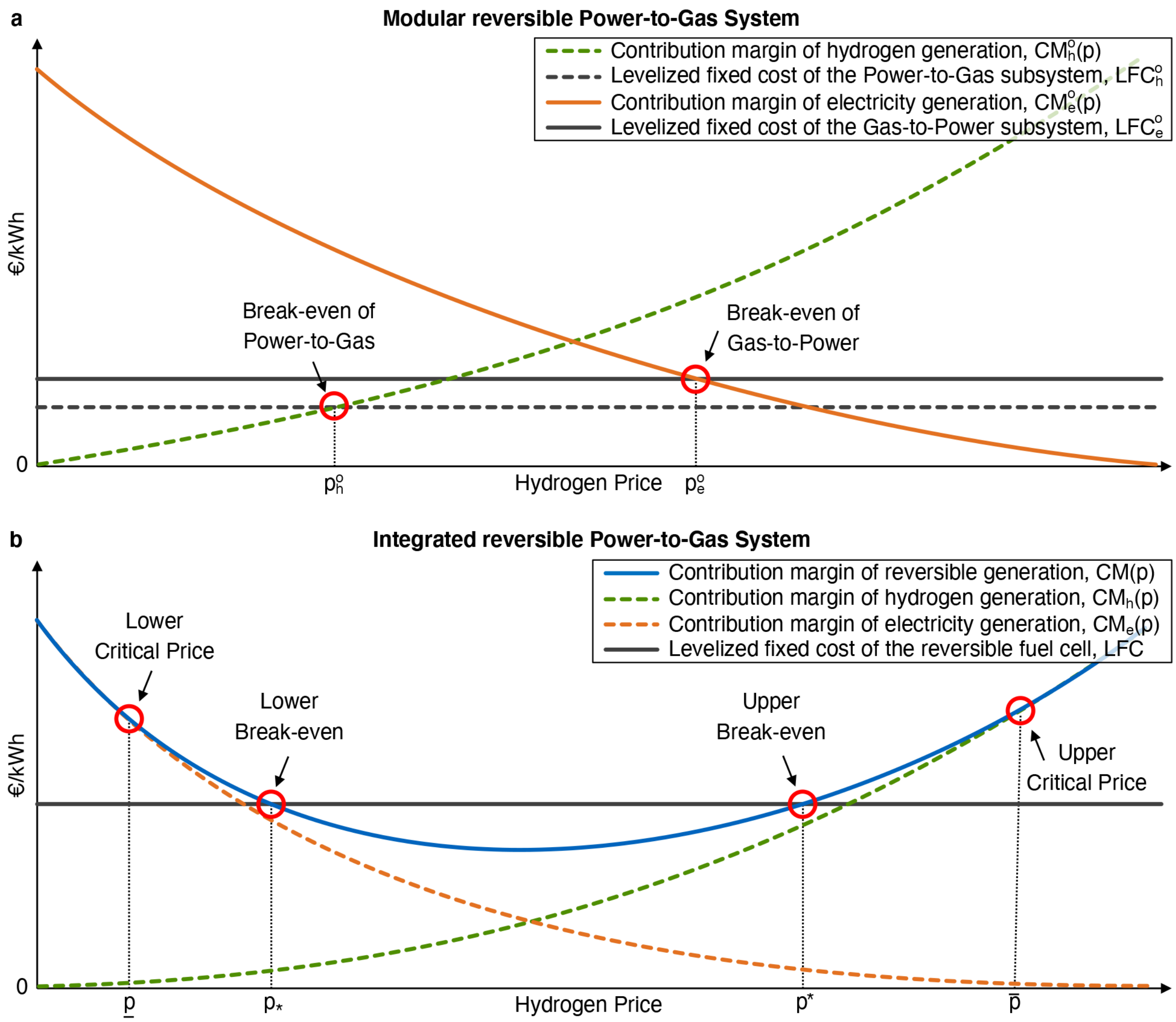


Figure 2: **Economics of a reversible Power-to-Gas system. a,b,** The figure illustrates the potential cost competitiveness and value of reversible operation in terms of the respective break-even prices of (**a**) a modular reversible Power-to-Gas system, and (**b**) an integrated reversible Power-to-Gas system.

Research.

Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector.

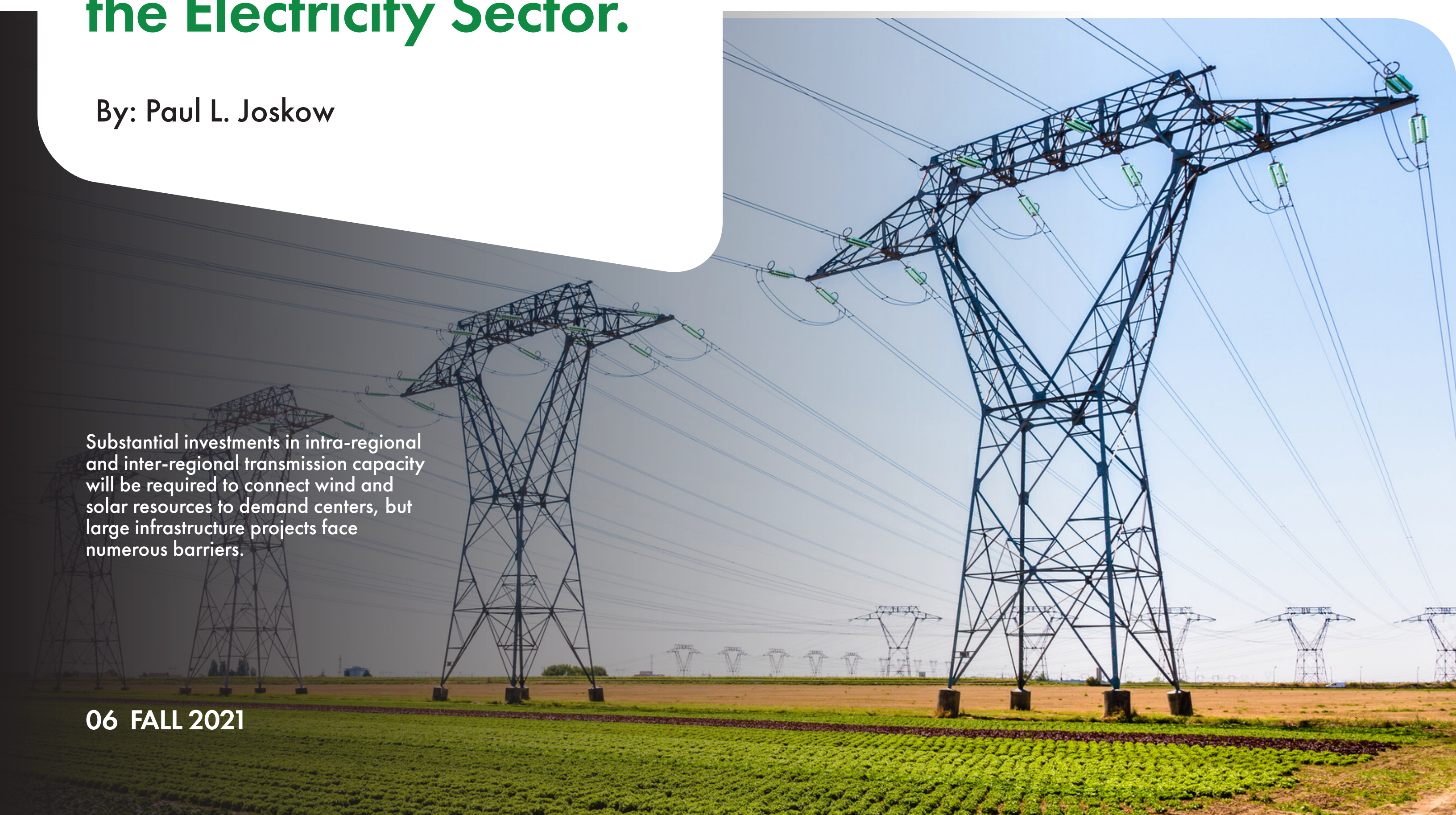
By: Paul L. Joskow

Many governments, electric utilities, and large electricity consumers have committed to deep decarbonization of the electricity sector by 2050 or earlier. Over at least the next 30 years, achieving decarbonization targets will require replacing most fossil-fueled generators with zero carbon wind and solar generation along with energy storage to manage intermittency. The best wind and solar resources are, however, located in geographic areas that are often far from the locations of the legacy stock of generating plants and their supporting transmission infrastructure.

It is therefore widely recognized that in order to meet governments' deep decarbonization commitments for the electricity sector in a cost-efficient manner, very substantial investments in intra-regional and inter-regional transmission capacity will be required to connect wind and solar resources to demand centers, better exploit diversity on the demand and supply sides of bulk power systems, and reduce curtailments of wind and solar as well as the quantity of generation and storage needed to meet reliability criteria.

Despite the potential advantages of expanding transmission capacity to improve access to and make more effective use of wind and solar resources, a number of barriers exist to exploiting these opportunities to meet decarbonization commitments economically and without violating various reliability criteria. As a result, the necessary transmission investments are lagging in the U.S., Europe, China and elsewhere.

A CEEPR Working Paper by Paul L. Joskow, Elizabeth and James Killian Professor of Economics, Emeritus at the Massachusetts Institute of Technology, assesses the importance of transmission expansion and relevant barriers. It begins by discussing the locations of the most attractive wind and solar sites in the U.S., Europe and China, affirming that the best wind and solar resources tend to be fairly remote from load centers, legacy power plants and/or existing transmission infrastructure.



Substantial investments in intra-regional and inter-regional transmission capacity will be required to connect wind and solar resources to demand centers, but large infrastructure projects face numerous barriers.

In a second substantive section, the Working Paper reviews the results of several modeling studies that examine the role that transmission expansion plays in meeting carbon mitigation goals in a cost-efficient manner. One common conclusion of these studies suggests that, in order to achieve deep decarbonization targets relying heavily on wind, solar, and storage at the lowest cost, significant increases in intra- and inter-regional transmission capacity will be required both inside the geographic boundaries of transmission system operators (TSO) and between the current boundaries of two or more TSOs.

In a third substantive section of the Working Paper, Joskow discusses the relevant attributes of transmission systems and TSOs in the U.S. and Europe, highlighting commonalities and differences with relevance for transmission expansion within and beyond the geographic boundaries of transmission systems. A subsequent fourth section traces how these attributes bear out in practice by surveying five case studies of national and international transmission expansion projects in the U.S. and Europe: the Pacific Northwest-Southwest AC/DC Intertie; Phase 2 of the HVDC link between Quebec and New England; the Northern Pass Transmission project and the related New England Clean Energy Connect project; the development of additional transmission capacity between France and Spain; and the planned construction of additional transmission lines connecting northern and southern parts of Germany.

Building on insights from this survey of selected case studies, Joskow draws out different types of barriers and potential mitigating solutions in the fifth and most comprehensive section of the Working Paper. One set of barriers results from stakeholder opposition to major new transmission projects, which can stem from a variety of concerns, such as: perceived visual impacts; impacts on recreational values; economic impacts; increased supplies from competitors; and potential health effects.

To mitigate such opposition, Joskow proposes a suite of potential solutions, from identifying and engaging with the stakeholder groups which are most likely to oppose and support the proposed project as early as possible in the development and permitting process, and mitigating project impacts at the initial design stage in consultation with stakeholders, to being prepared to compensate stakeholders who are affected by the project but do not benefit directly from it, and working with relevant federal, state, and local authorities to consolidate necessary regulatory reviews required for the project to receive the necessary permits.

Identified barriers go well beyond these types of stakeholder opposition, however: there are organizational barriers resulting from excessively narrow transmission system planning protocols and relevant geographic expanses; barriers created by considering too narrow a range of benefits associated with transmission capacity enhancements; barriers created by disputes over how the costs of these facilities will be allocated to users of the system; barriers resulting from currently applied compensation (cost recovery) and financing barriers; and, finally, in the U.S. barriers from the lack of a unified national decarbonization policy. Comparing and contrasting U.S. and European responses to these challenges, Joskow sets out a series of suggestions for institutional, regulatory, planning, compensation and cost allocation policies that can reduce the barriers to efficient expansion of transmission capacity. Affirming that Europe has made greater progress on some of these challenges, he cautions that mere adjustments to existing regulations and institutions in the U.S. are unlikely to accelerate investments in the transmission capacity needed to support an efficient decarbonization path.

Two sets of institutional change, he argues, should be high on the agenda for the U.S.: a more holistic approach to considering potential benefits from proposed transmission capacity expansion plans, coupled with expanded use of competitive procurement and determination of who should pay by applying cost causality and beneficiary pays principles; and the creation of a national transmission planning organization that can serve as an umbrella transmission planning organization to evaluate a full range of wide-area transmission project opportunities in meaningful detail.

Paul L. Joskow (2021), "Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector", CEEPR WP-2021-009, MIT, June 2021.

Research.

Challenges and Opportunities for Decarbonizing Power Systems in the US Midcontinent.

By: Pablo Duenas-Martinez, Karen Tapia-Ahumada, Joshua Hodge, Raanan Miller, and John E. Parsons

This study examines the situation across the U.S. midcontinent, encompassing a set of power systems stretching from Ohio in the east to the plain states in the west, and from Minnesota in the north to Louisiana in the south. We focus on a near-term horizon of 2030, where the tradeoffs are between already commercially available technologies utilizing the existing transmission grid. We use a capacity expansion and dispatch model configured to examine the task of serving the fluctuating hourly load throughout a full year given the fluctuating availability of renewable resources. With it, we explore the impact of decarbonization on the generation mix, operations, and costs.

Many forces have already been transforming generation supply stacks across the region, including the low price of natural gas, the falling cost of renewables, especially wind power, tax incentives and other public support for renewable investments, and tightened air pollution regulations. Stagnant power demand has kept wholesale prices low. Many coal and nuclear assets have taken hits to their valuations. Some have been retired early and more may be retired in the coming years. We first examined how the generation mix might continue to change in the absence of any further policies. To do so, we parameterized the model with a set of forecasted investment and operating costs for generation technologies taken from the National Renewable Energy Laboratory's Annual Technology Baseline exercise, and a set of fuel cost projections from the U.S. Energy Information Administration's Annual Energy Outlook.

The results show a continuation of recent trends producing a limited 11% emission reduction relative to the 2018 simulation. At the system level, fossil fuel-fired capacity of all types decline, but coal and natural gas-fired plants remain the two largest categories of capacity. A small amount of nuclear capacity is retired, too. New investments are large in both wind and solar capacity with solar accounting for more than 2/3 of the added capacity.

We then examined mixes of capacity that achieve substantial emission reductions cost-efficiently. For example, we find that a 77% reduction is achievable by any suite of policies that is comparable to pricing carbon at \$25/t CO_2. The source of emission reductions is an enormous substitution of coal generation with a mix of natural gas, wind and solar generation and by avoiding the closure of existing nuclear. Natural gas capacity and generation are higher than in the Reference Case. Deeper emission reductions require marching up a steepening marginal cost of abatement curve. We get an 84% and a 90% reduction at a \$50 and a \$100/t CO_2 price, respectively.

Finally, we considered alternative policy direction that focuses exclusively on expanding renewable generation. This is not cost-efficient. It achieves more modest emission reductions at a higher system cost. In our modeling, a 75% RPS produces a 64% emission reduction while raising the annual system cost by \$5 billion, a 10% increase.

One source of the inefficiency is a failure to target the most carbon intensive plants for shutdown. Relative to the cost efficient policy, it has more coal generation and less natural gas generation.

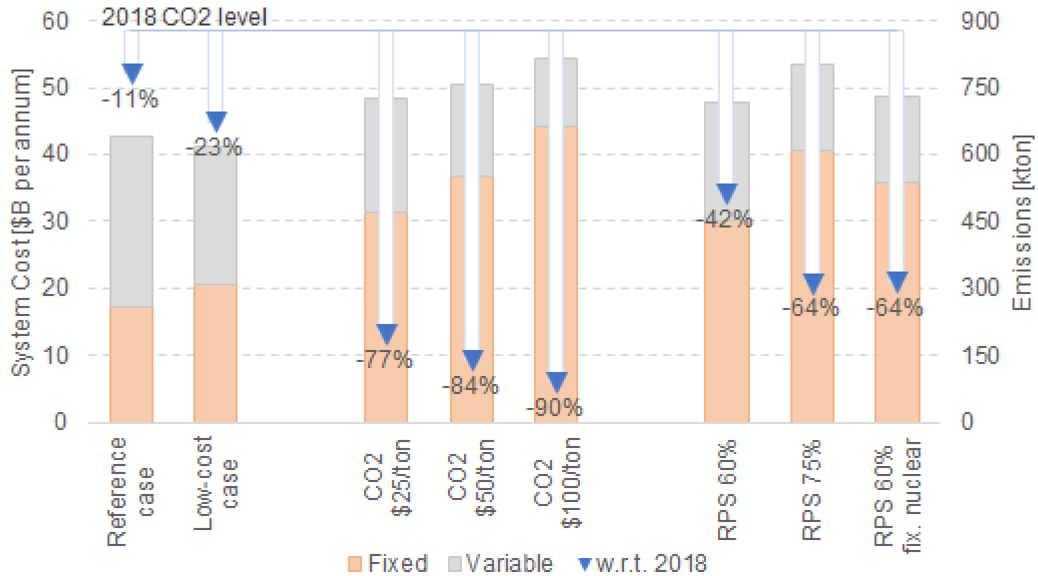


Figure 1. System-wide emission reductions relative to 2018 and average annual system costs across eight scenarios.

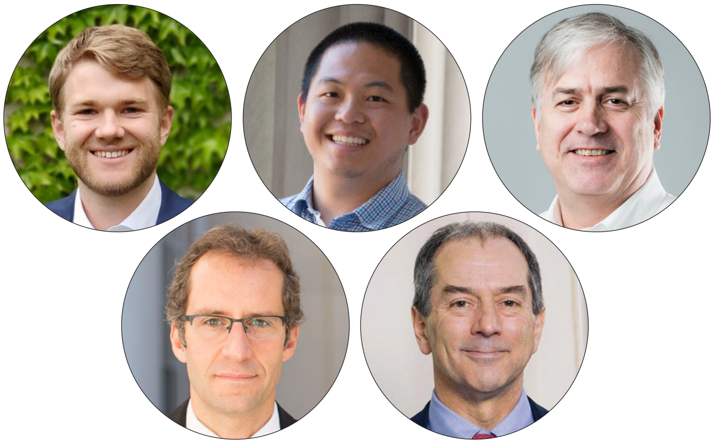
A second source of the inefficiency is its impact on nuclear generation. The entire nuclear fleet is retired, sacrificing 256 GWh of zero-carbon generation.

The paper also analyzes how the changing generation mix produces changes to operating profiles and market outcomes. One is a shift in the utilization of fossil plants away from provision of baseload towards balancing fluctuating renewable resources. The fleet capacity factor declines with decarbonization. At the same time, these fossil plants are critical during a few hours to guarantee the reliable delivery of electricity. In fact, in our modeling, we observe investments in gas power plants in light of this need for flexibility.

We also report added volatility to the marginal cost of electricity, a metric that is sometimes used as a proxy for the wholesale energy price. Under deeper decarbonization scenarios, the extreme tails of the distribution grow—benchmarked by $0/MWh at the low end and $100/MWh at the high end. The trend is more marked in those regions with the higher concentration of renewables and where congestion is greatest.

Pablo Duenas-Martinez, Karen Tapia-Ahumada, Joshua Hodge, Raanan Miller, and John E. Parsons (2021), "Challenges and Opportunities for Decarbonizing Power Systems in the US Midcontinent", CEEPR WP-2021-011, MIT, July 2021.

Andrew T. Bouma, Quantum J. Wei, John E. Parsons, Jacopo Buongiorno and John H. Lienhard V (2021), "Water for a Warming Climate: A Feasibility Study of Repurposing Diablo Canyon Nuclear Power Plant for Desalination", CEEPR WP-2021-012, MIT, July 2021.



Research.

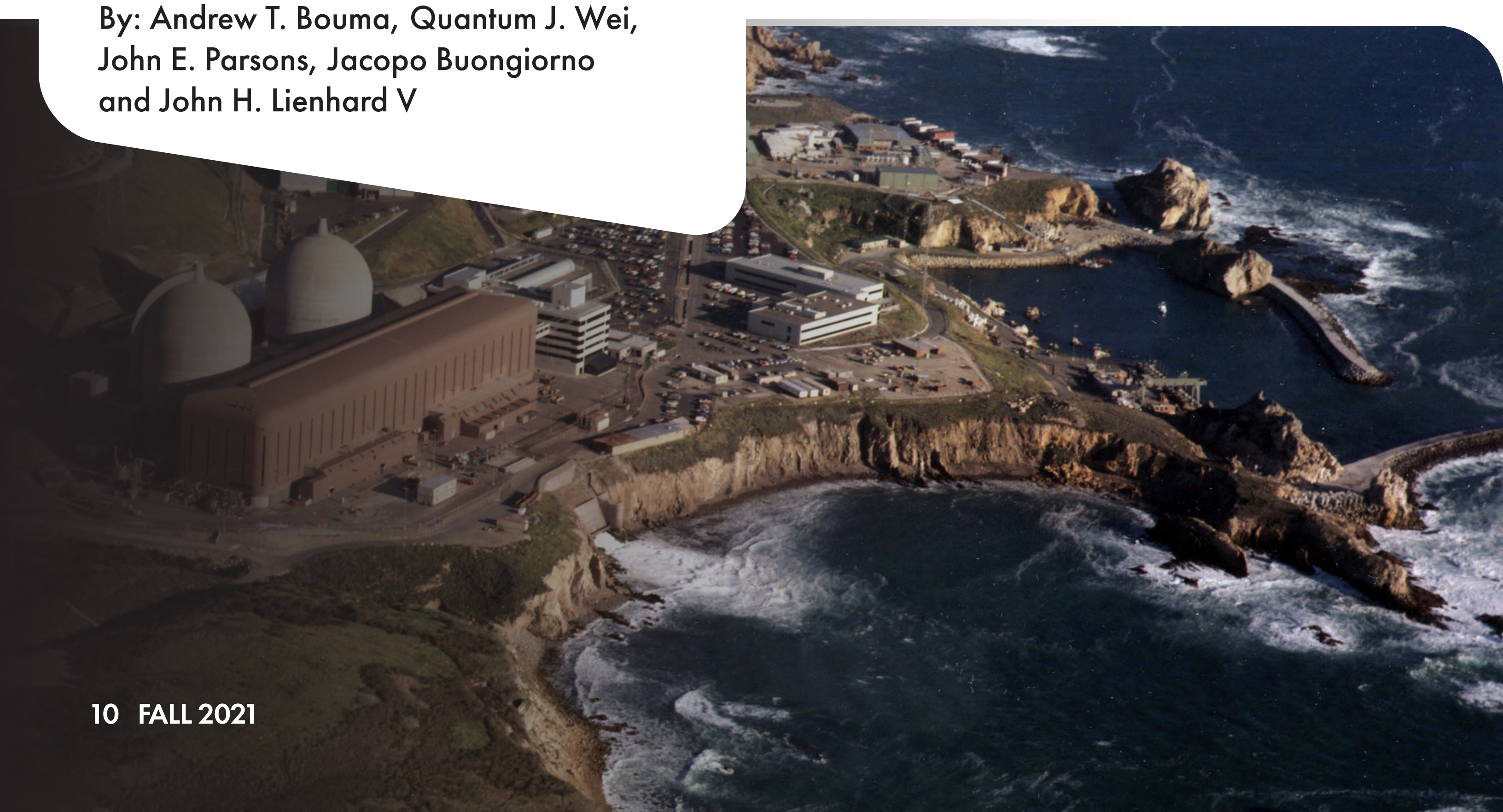
Water for a Warming Climate: A Feasibility Study of Repurposing Diablo Canyon Nuclear Power Plant for Desalination.

By: Andrew T. Bouma, Quantum J. Wei, John E. Parsons, Jacopo Buongiorno and John H. Lienhard V

California has a pressing need for additional sustainable fresh water supplies. This report explores the feasibility and economic benefits of co-locating a large seawater desalination plant at the Diablo Canyon Nuclear Power Plant (DCNPP) to supply potable water to the state. A key challenge for any desalination plant and for continued operation of DCNPP is compliance with California's regulations protecting marine organisms from large intake structures. We show how a new brushed-screen intake structure, serving both the nuclear power plant and the desalination plant, achieves compliance. This arrangement integrates the desalination plant with the nuclear power plant by sharing infrastructure and receiving feedwater and power from the nuclear power plant, forming a water-power coproduction system. The cost of desalinated water from coproduction is much cheaper than the cost from an alternative stand-alone plant.

We evaluated four options for configuring a seawater reverse osmosis desalination plant at the DCNPP. The smallest option (see Figure 1 on the next page) has a capacity of about 190,000 m^3/d, which is also the nameplate capacity of the Carlsbad Desalination Plant in San Diego County, and approximately the same size as the proposed plant at Huntington Beach. There are a number of interesting benefits of building at this scale, including lower salinity brines after the desalination brine is mixed with the power plant cooling water, which would obviate the need for high-energy diffuser outfalls and allow for the existing outfall infrastructure to remain in place. In this configuration, the electrical requirement of the desalination plant is very small compared to the size of the nuclear power plant.

A key challenge for any desalination plant and for continued operation of DCNPP is compliance with California's regulations protecting marine organisms from large intake structures. The California Ocean Plan regulates intakes for desalination plants and places strict limits on the impingement and entrainment of marine life. A separate regulation for power plants requires existing power plants using once-through cooling to reduce their intake flow rate by 93%. If not feasible, power



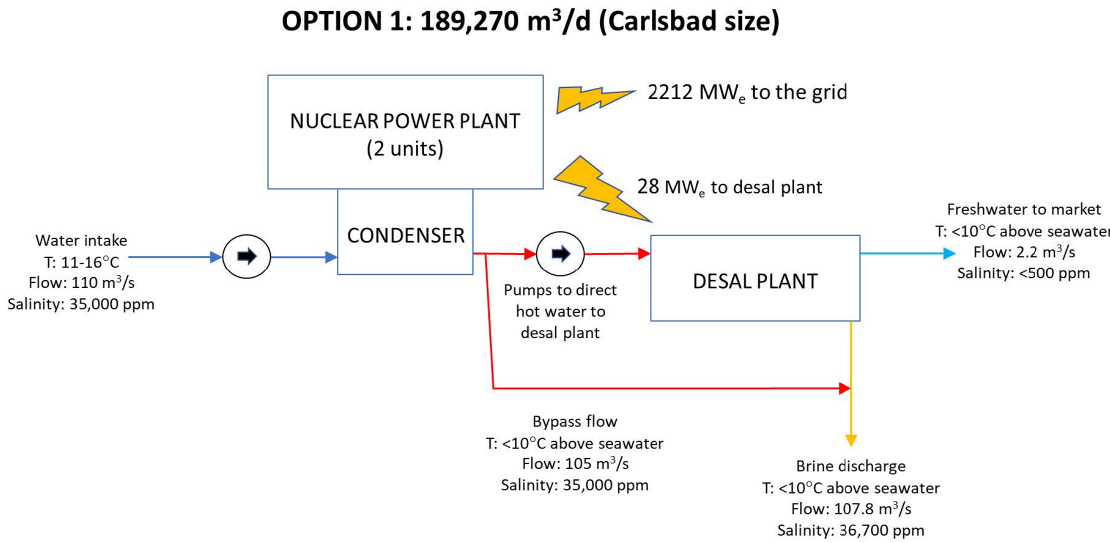


Figure 1. Option 1: Large-scale desalination plant similar to existing plants.

plants are able to instead put into place measures that reduce the impingement and entrainment of marine life for the facility by a comparable level. These regulations are the primary technical reason for the impending shutdown of DCNPP.

The compliance option we incorporate into our analysis is the construction of submerged screen intakes with a mesh size of 1 mm or less, and a flow velocity at the screen of no more than 0.5 feet per second (15 cm/s). Although these conditions can lead to rapid fouling of the intake screens, screens can be cleaned by a number of methods, such as with an air burst, mechanical cleaning, or by divers. For the purpose of this analysis, though, Intake Screens, Inc. (ISI) of Sacramento has provided us initial estimates regarding mechanical brush-cleaned wedgewire screens, which will likely be one of the most competitive options. Similar intake systems have been specified for the Huntington Beach desalination plant and are currently being tested at Carlsbad as a potential replacement for the existing intake. Key to ISI's design is a submersible electric-drive assembly that rotates wedgewire screen cylinders between nylon brushes. The exterior of the wedgewire is cleaned by a fixed position external brush and the interior of the screen is cleaned by an internal brush that rotates. This brush-cleaning system has proven effective at maintaining a clean screen surface in a number of applications with challenging fouling environments.

To place the screens in an appropriate offshore, deep water location that minimizes potential impacts to aquatic resources, the existing shoreline basin would be closed off from the Pacific Ocean by extending the existing breakwater structure, and a drop shaft constructed to a bored tunnel approximately 335 meters long terminating at the manifold array. This arrangement allows for the power plant to continue to operate continuously throughout the construction of the new intake, as the existing power plant intake pumps and structure are unchanged (see Figure 2).

There are significant economic advantages for a DCNPP-desalination coproduction plant as compared against an alternative stand-alone desalination plant. The savings from sharing of the new intake and existing outfall structures are significant. In addition, the cost of power is substantially reduced. The levelized cost of water for the smallest option is estimated at $0.98 per m^3 at the plant outlet, as compared against $1.84 per m^3 from a comparable stand-alone desalination plant.

The scope of our analysis has been limited to techno-economic feasibility, and we find that co-locating a desalination plant at Diablo Canyon is technically feasible and economically beneficial. Of course, myriad additional factors should be considered before Californians make a judgment on whether such a plant is the preferred solution for water needs of the California Central Coast or for wider parts of the state.

Figure 2. Aerial view of DCNPP with extended breakwater to isolate lagoon, emergency inlet structure, tunnel extending offshore, and wedgewire screen array for Option 1 configuration outlined in Figure 1.

Research.

Intermittent versus Dispatchable Power Sources: An Integrated Competitive Assessment.

By: Gunther Glenk and Stefan Reichelstein

The costs of replacing dispatchable power sources based on fossil fuels with intermittent renewable power sources remain controversial. The life-cycle cost of renewables, in particular wind and solar power, is known to have fallen substantially over time (Jansen et al., 2020; Steffen et al., 2020; Rubin et al., 2015). Once deployed, these power sources also have effective priority in the marketplace due to their zero short-run production cost. In contrast, the life-cycle cost of traditional dispatchable generation sources tends to increase due to lower capacity utilization as these facilities are increasingly relegated to delivering output during hours when intermittent renewables are not available (Bushnell & Novan, 2021; Kök et al., 2020).

While all of these cost effects favor renewable power, countervailing effects emerge on the revenue side (Millstein et al., 2021; Das et al., 2020). First, renewables increasingly experience a "cannibalization" effect in jurisdictions where significant additions of wind or solar power capacity cause market prices to fall during hours when renewable sources are at peak capacity (López Prol et al., 2020, Hirth, 2013). A second effect favoring the value generated by dispatchable energy sources is the price premium they earn at times of limited supply capacity due to the intermittency of renewables (Antweiler & Muesgens, 2021).

This paper provides an integrated assessment of the cost and value dynamics of solar photovoltaic (PV), onshore wind, and natural gas combined-cycle (NGCC) power plants in the context of the wholesale electricity markets in Texas and California. Our empirical findings are based on a novel metric termed the Levelized Profit Margin (LPM). This metric is shown to capture the relevant unit economics in terms of dollars per kilowatt-hour (kWh) for assessing the competitiveness of alternative power generation technologies. Key to the calculation of this profit margin is that the average market price for electricity in a particular year and jurisdiction is adjusted by a technology-specific factor that captures the covariance between real-time fluctuations in electricity prices and optimized capacity utilization rates. The economic profitability of a power generation facility thus hinges on a weighted average of the future technology-adjusted unit revenues to exceed the life-cycle cost of energy generation. A dynamic LPM analysis thus integrates the countervailing competitive effects due to technological improvements, shifts in capacity utilization, cannibalization, and the dispatchability price premium.

Our findings indicate that for the most part new capacity investments in both renewables or natural gas plants undertaken during the years 2012-2019 are thus far not on track to become economically profitable. This finding may reflect that new investments were based on criteria that extend beyond expected net present values, such as renewable portfolio standards in California or the presence of "impact investors", such as technology firms investing in renewable energy projects (Borenstein, 2012; Comello et al., 2021).

At the same time, our results indicate that the estimated LPMs of new wind and solar energy projects have improved considerably and, by 2019, approached or exceeded the break-even value of zero. This finding is primarily due to substantial reductions in the life-cycle costs of these power sources. In California, the LPM improvements of solar PV

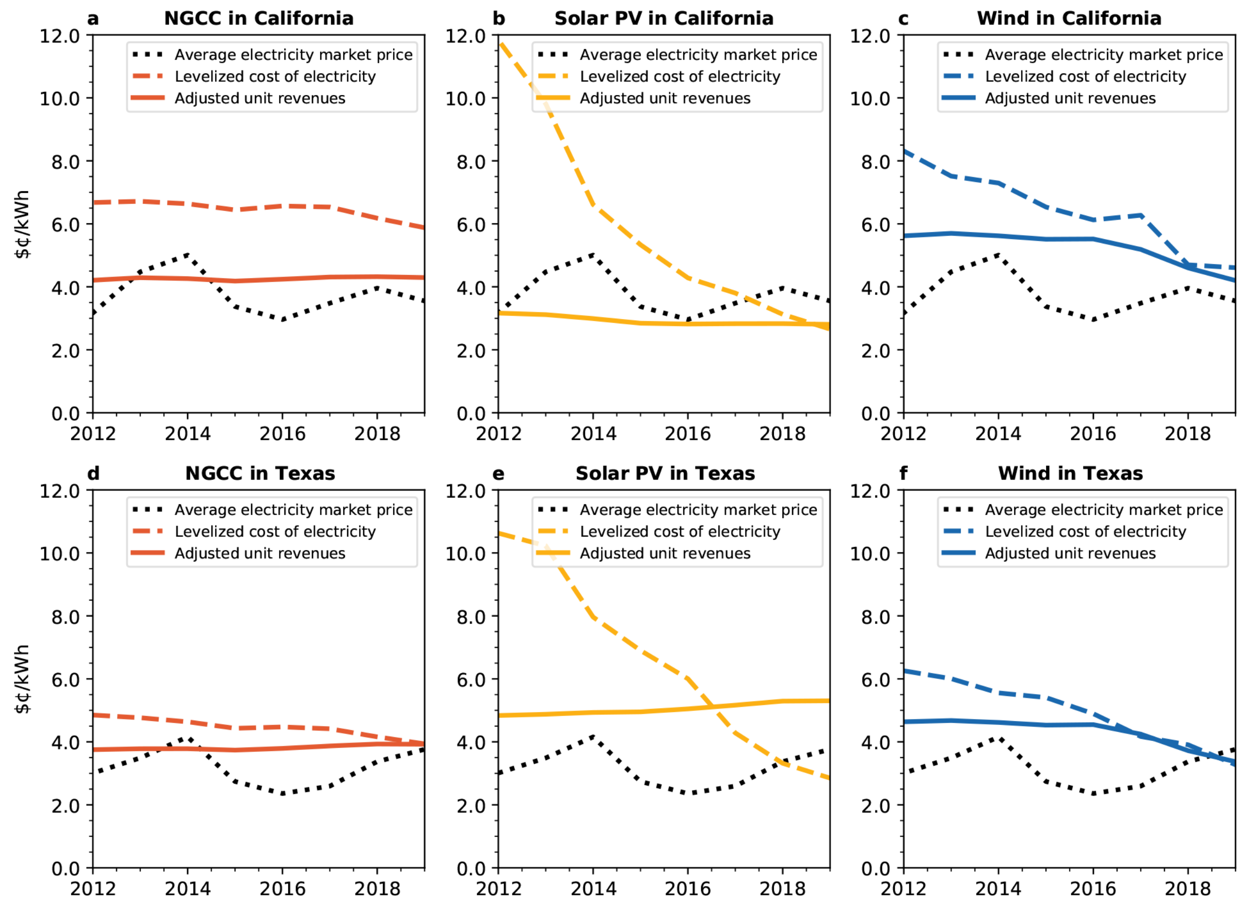


Figure 1. Trajectory of levelized profit margins (scenario 1). a, b, c, d, e, f, This figure shows the trajectory of levelized profit margins for NGCC turbines in California (**a**), solar PV in California (**b**), onshore wind in California (**c**), NGCC turbines in Texas (**d**), solar PV in Texas (**e**), and onshore wind in Texas (**f**) as the difference between the weighted average of adjusted unit revenues (colored solid lines) and LCOE (colored dashed lines).

have been partially offset by a tangible cannibalization effect (Woo et al., 2011, 2016). In contrast, solar PV has achieved a growing price premium in Texas, a state where solar power today still has a relatively modest market share.

For NGCC power plants in California, we find that falling capacity utilization rates have been counterbalanced by increasing dispatchability price premia. These two countervailing trends have resulted in steady but distinctly negative LPMs. In Texas, by contrast, profit margins for NGCC plants have improved due to higher utilization rates at times of higher power prices. This finding is consistent with the general observation that in Texas natural gas and wind power have gradually replaced coal-fired generation (Fell & Kaffine, 2018).

Gunther Glenk and Stefan Reichelstein (2021), "Intermittent versus Dispatchable Power Sources: An Integrated Competitive Assessment", CEEPR WP-2021-013, MIT, August 2021.

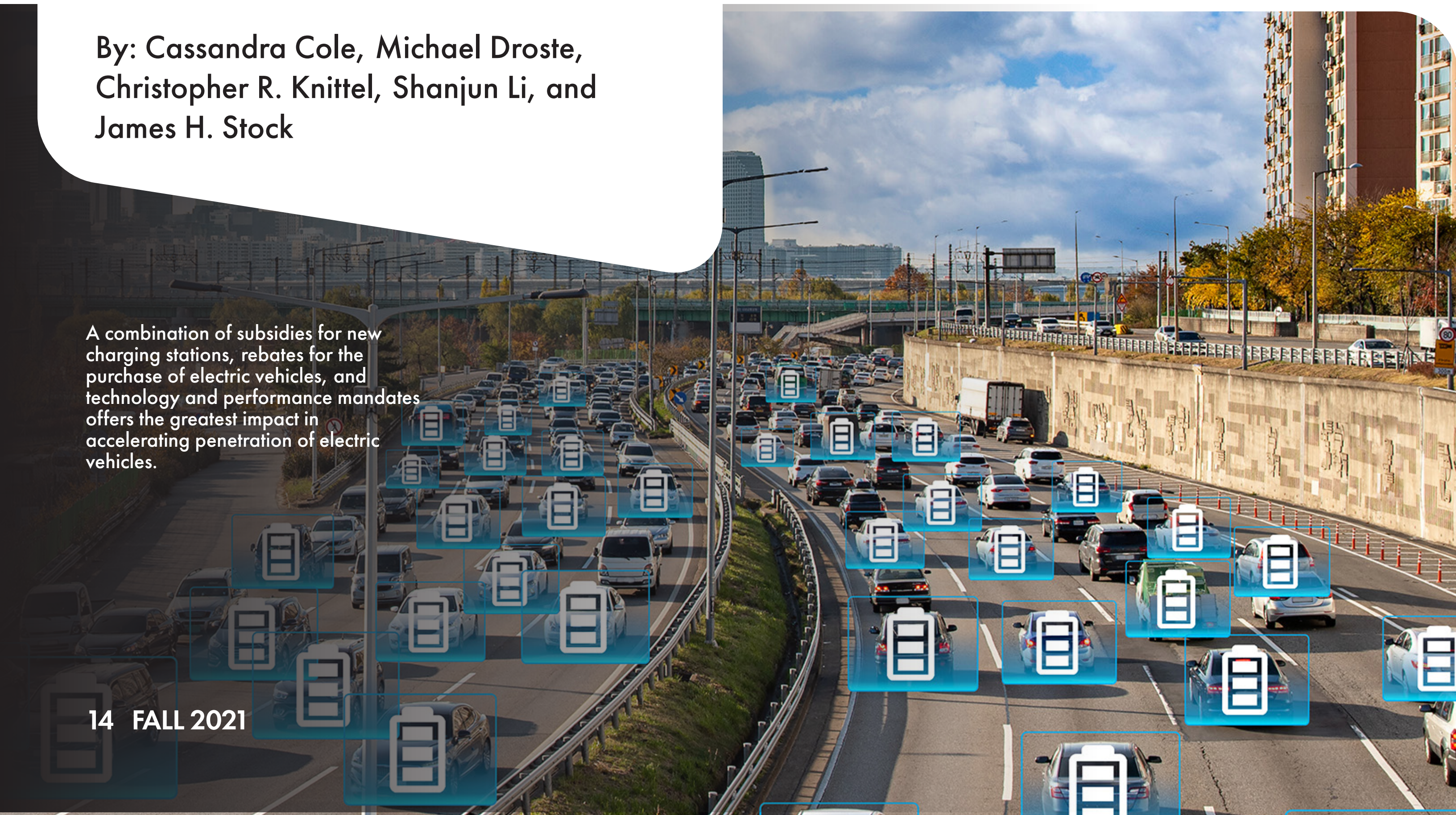
Cassandra Cole, Michael Droste, Christopher R. Knittel, Shanjun Li, and James H. Stock (2021), "Policies for Electrifying the Light-Duty Vehicle Fleet in the United States", CEEPR WP-2021-014, MIT, September 2021.




Research.

Policies for Electrifying the Light-Duty Vehicle Fleet in the United States.

By: Cassandra Cole, Michael Droste, Christopher R. Knittel, Shanjun Li, and James H. Stock



A combination of subsidies for new charging stations, rebates for the purchase of electric vehicles, and technology and performance mandates offers the greatest impact in accelerating penetration of electric vehicles.

The decarbonization of the light duty vehicle (LDV) sector is a major policy priority in the United States. In 2019, 58% of U.S. transportation carbon emissions arose from the operation of LDVs. The Biden Administration has declared a target of 50% new vehicle sales in 2030 consisting of zero-emissions vehicles: battery electric vehicles (BEVs), plug-in hybrid electric vehicles (PHEVs) and hydrogen fuel cell vehicles. In Europe, the UK government has announced an even more aggressive ban on the sale of new gasoline and diesel cars and vans in 2030, with hybrid cars and vans phased out by 2035.

Accordingly, major automakers have announced ambitious plans for expanding their production of electric vehicles. Ford Motor Co., for instance, will invest $22 billion through 2025 in electrifying transportation, including producing fully electric versions of its vans and pickup trucks. Likewise, General Motors Co. plans to produce 30 new electric vehicle (EV) models by the end of 2025, transition to producing only EVs by 2035, and become carbon neutral by 2040, while simultaneously investing in battery technology. By the end of the decade, Volkswagen plans to launch approximately 70 BEV and 60 hybrid models, including 20 BEVs and more than 30 hybrids already in production. All three companies have also committed to expanding EV charging infrastructure.

As automakers increase their production of electric vehicles and components – notably electric batteries – replacing conventional internal combustion engine (ICE) vehicles with EVs appears to be the most promising pathway for decarbonizing LDVs in the near future. Moreover, doing so increasingly appears economically feasible: prices of lithium-ion battery packs decreased by 16% annually between 2017 and 2019, with average battery prices reaching $137/kWh and reports of some battery packs reaching less than $100/kWh in 2020. Yet deep EV penetration is not a certainty, and policy may play an important role in expediting and supporting the transition. To this end, a variety of policies have been proposed to spur electrification of the US

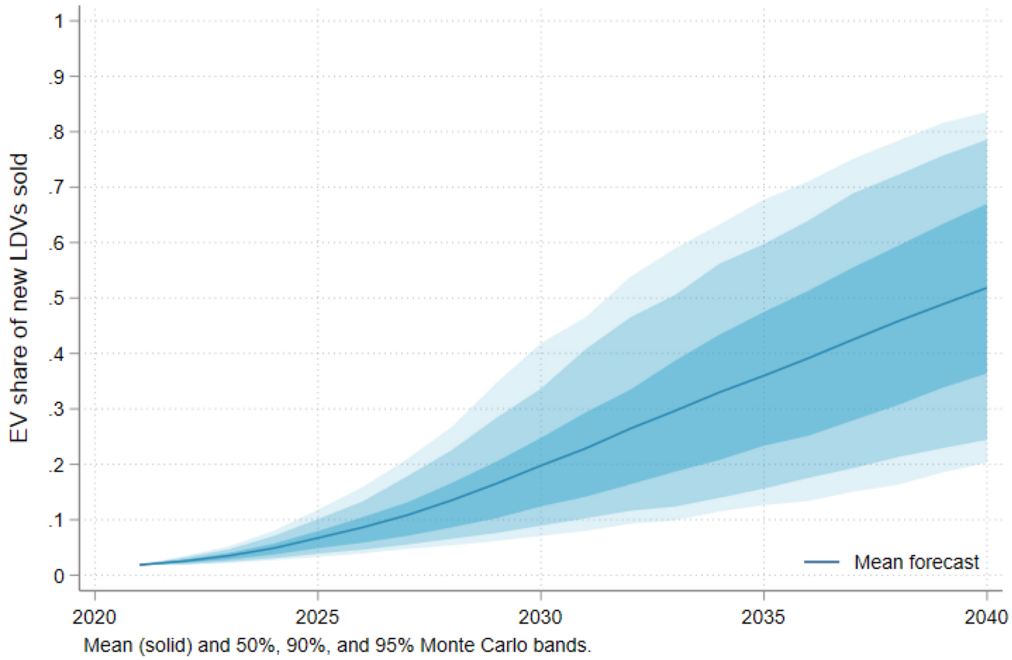


Figure 1. Baseline Electric Vehicle Share of New Vehicles Sold

Notes: This figure plots our baseline forecast of the EV sales share of new vehicles sold through 2050. The shaded area indicates a 90 percent confidence interval obtained via Monte Carlo simulation, as described in the full paper.

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EV fleet. Broadly, these include building charging infrastructure, subsidizing the costs of purchasing or driving EVs, and regulatory approaches that use existing legal authorities of the Environmental Protection Agency (EPA) to regulate CO_2 emissions and the Department of Transportation (DOT) to regulate fuel economy.

In order to evaluate this suite of policies for expediting electrification of the LDV fleet, a CEEPR Working Paper authored by a team of researchers from Cornell University, Harvard University, and CEEPR Faculty Director Christopher R. Knittel applies a joint model of charging station supply and EV demand. The authors then simulate the diffusion path of EVs under different policy scenarios including refundable tax credits, charging station subsidies, and tradeable allowances, and vary the size of the subsidies and total program budgets for both vehicles and charging stations to obtain the share of battery EVs, the reduction in greenhouse gases, and total governmental outlays.

Specifically, the three policies evaluated by the authors are: government-subsidized production of new charging stations through a cost-sharing program in which the government pays a percentage subsidy to each charging station built until the federal budget allocation is spent, at which point the program ends; a rebate for the purchase of electric vehicles that reduces the sticker price of electric vehicles, reducing the price of EVs relative to ICEs through a point-of-sale rebate to the consumer, a point-of-sale dealer rebate, or a refundable tax credit; and a policy that sets both the fuel efficiency of ICE vehicles and mandates the fraction of EVs sold, both by class of vehicle.

Based on the application of the model to these policies, the authors make two important findings. First, there is a great deal of heterogeneity (in terms of impact on EV penetration per dollar of government expenditure) across the policies studied. Second, none of the three policies studied in isolation is capable of reaching 50% EV penetration in the market for new vehicles without a very large price tag; instead, a combination of policies is likely to provide the most impact on EV penetration.

Two reasons are cited to explain these conclusions. First, for individuals who cannot install their own chargers, for example because they park on a street or live in an apartment building, buying and EV simply is not an option, regardless of how deep the subsidy is. For them, providing additional charging stations makes it possible to purchase an EV. Even for consumers who have their own personal charging stations, the current low density of on-the-road level 3 chargers makes long-distance travel challenging at best. For them, additional level 3 chargers reduce range anxiety and make it possible to use EVs in the way that drivers now use ICEs.

Second, much of spending on tax credits is inframarginal; it consists of transfers to individuals who would have purchased an electric vehicle whether or not the tax credit we study exists. And although individuals are highly responsive to changes in the relative price of cars or electric vehicles, an appreciably large subsidy for EV purchases would amount to hundreds of billions of dollars in government transfers.

The Working Paper authors concede that their analysis makes many simplifications and has limitations. While in practice EV sales rebates could be capped at specific vehicle prices to potentially better target marginal consumers, the model applied for this study does not permit such a level of nuance. Additionally, there are many potential extensions of the model which may prove significant and have not been incorporated here; allowing consumer choice between cars and SUVs, incorporating more evidence on the nuances of level 2 vs. level 3 charging station supply and demand, and simply making the charging station model more granular all have the potential to provide policy-relevant insight. Addressing these limitations is a topic for ongoing research.

Research.

Technology Adoption and Early Network Infrastructure Provision in the Market for Electric Vehicles.

By: Nathan Delacrétaz, Bruno Lanz, and Jeremy van Dijk

Car use is associated with significant negative local and global external costs (e.g., from pollution), and many consider electrification as the future of on-road transportation. Even in the presence of externality-correcting taxes, however, indirect network effects hamper individual decisions to purchase an electric vehicle (EV) (Greaker and Midttomme, 2016). In particular, the benefit of EV adoption depends on the size of charger networks, whereas providers of charging stations will not invest in infrastructure provision when the number of EVs in circulation is small. Such unpriced benefits to consumers (e.g. lower charger search costs) likely result in suboptimal private deployment of network infrastructure (Farrell and Saloner, 1986; Katz and Shapiro, 1986; Cabral, 2011). Thus, policies supporting early provision of public charging infrastructure can alleviate a chicken and egg dilemma between EV consumers and charging station providers.

This paper provides novel evidence about how increments to charging infrastructure affect EV adoption decisions, and studies how consumers respond to charger installations at early and developed market stages. We employ data for all 422 Norwegian municipalities from 2010-2017 of detailed car model-level data for EV registrations and the number of available charging stations, plus the number of charging points within these. This period covers the modern EV market beginnings through to maturity.

With our first analytical method, we take an instrumental variable approach due to potential endogeneity between municipality-level EV purchases and charger installations, which can both be affected by unobserved factors, and reverse causality from car registrations to charging station provision. In a similar vein to Li et al. (2017) we instrument using public parking spaces in each municipality, arguing that more parking space plausibly exogenously identifies potential for charging station installation. This is then interacted with the lagged national number of charging stations, assuming that municipalities with more parking space are more likely and able to respond to the national EV adoption trend with new chargers.

Using sets of polynomial control function (CF) regressions alternately on charging station and charging point numbers, we demonstrate that the largest return to charger investments is when there is little to no pre-existing network. There is a declining marginal benefit to new charging infrastructure as the network size grows. We further show that consumers exhibit a larger reaction to more charging stations with fewer points than more points across fewer stations, indicating a preference for a more dispersed charger network and potential consumer range anxiety (DeShazo et al., 2017). At the mean we estimate a 10 percent increase in charger stations increases EVs by 1.4 percent. For charging points the corresponding estimate is 0.9 percent.

Our second analytical method focuses on a subset of 64 municipalities that started with zero charging stations in 2010, and who installed one (one-station group) or multiple within a window of four consecutive quarters (multi-station group). We estimate the impact of these initial and one-off infrastructure installations using the synthetic control method (SCM) and the bias-correcting ridge-augmented SCM (Abadie and Gardeazabal, 2003; Abadie et al., 2010; Ben-Michael et al., 2018). Here we build synthetic comparison units for all treated municipalities using weighted sums of observations from a donor pool of those who

Table 3: Baseline results from panel data estimation

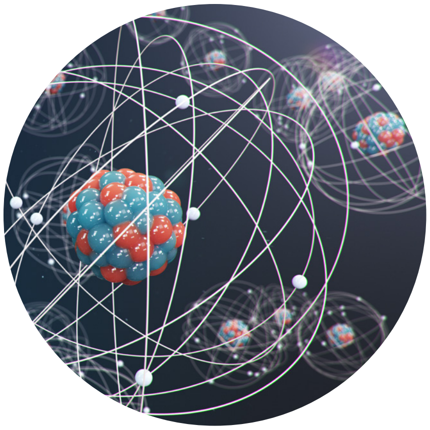
	Charging stations		Charging points	
	OLS	2SLS	OLS	2SLS
	(1)	(2)	(3)	(4)
ln(charging stations)	-0.008	0.126^{**}	–	–
	(0.006)	(0.054)		
ln(charging points)	–	–	-0.004	0.074^{***}
			(0.003)	(0.026)
ln(car price)	0.108^{***}	0.110^{***}	0.108^{***}	0.110^{***}
	(0.008)	(0.008)	(0.008)	(0.008)
ln(income)	-0.007	-0.036	-0.007	-0.025
	(0.092)	(0.109)	(0.092)	(0.110)
ln(income) x Time	-0.0002	0.0001	-0.0003	-0.0001
	(0.005)	(0.005)	(0.005)	(0.005)
ln(hybrids) x Time	0.008^{***}	0.008^{***}	0.008^{***}	0.008^{***}
	(0.001)	(0.001)	(0.001)	(0.001)
Constant	-1.298	-1.370	-1.290	-1.348
	(1.090)	(1.314)	(1.089)	(1.334)
N	367, 984	366, 296	367, 984	366, 296
Within-R^2	0.0779	0.0675	0.0779	0.0646
1st-stage partial F-stat.	–	19.01	–	25.54

Notes: In all columns, the dependent variable is the log of new electric vehicle registrations (ln(EV)mit). Columns (1) and (2) consider charging stations as the treatment variable, and columns (3) and (4) instead use charging points. All specifications include quarter and municipality-model fixed effects. The 1st stage partial F-statistic for the instrumental variable (columns (2) and (4)) are derived from first-stage regression reported in Appendix B, Table B1. Standard errors clustered at the municipality level reported in parentheses, and respectively denote significance at 10%, 5% and 1% levels.

never installed any charging stations, giving counterfactual trajectories for each had they not installed the chargers that they did. We find an increasing impact over time after installation. One year after charger provision, one-station and multi-station groups experienced on average 5.4 and 8.0 percent more EV registrations, respectively. One further year on, the average treatment effect rose to 21.7 and 46.2 percent more EVs than the control groups, respectively. This further confirms the large and unpriced benefits of early infrastructure provision, where policy intervention can significantly contribute to initiating adoption dynamics.

Taken together, our results suggest early charging infrastructure support has a sizable impact on EV adoption patterns. The first installations have a lasting and increasing effect, and the number of initial installations also matters. We demonstrate evidence of indirect network effects causing an initial hurdle to EV adoption and a declining effect of new chargers as the network grows. In addition, support for more stations has a larger impact than more access points across fewer stations given evidence of consumer range anxiety.

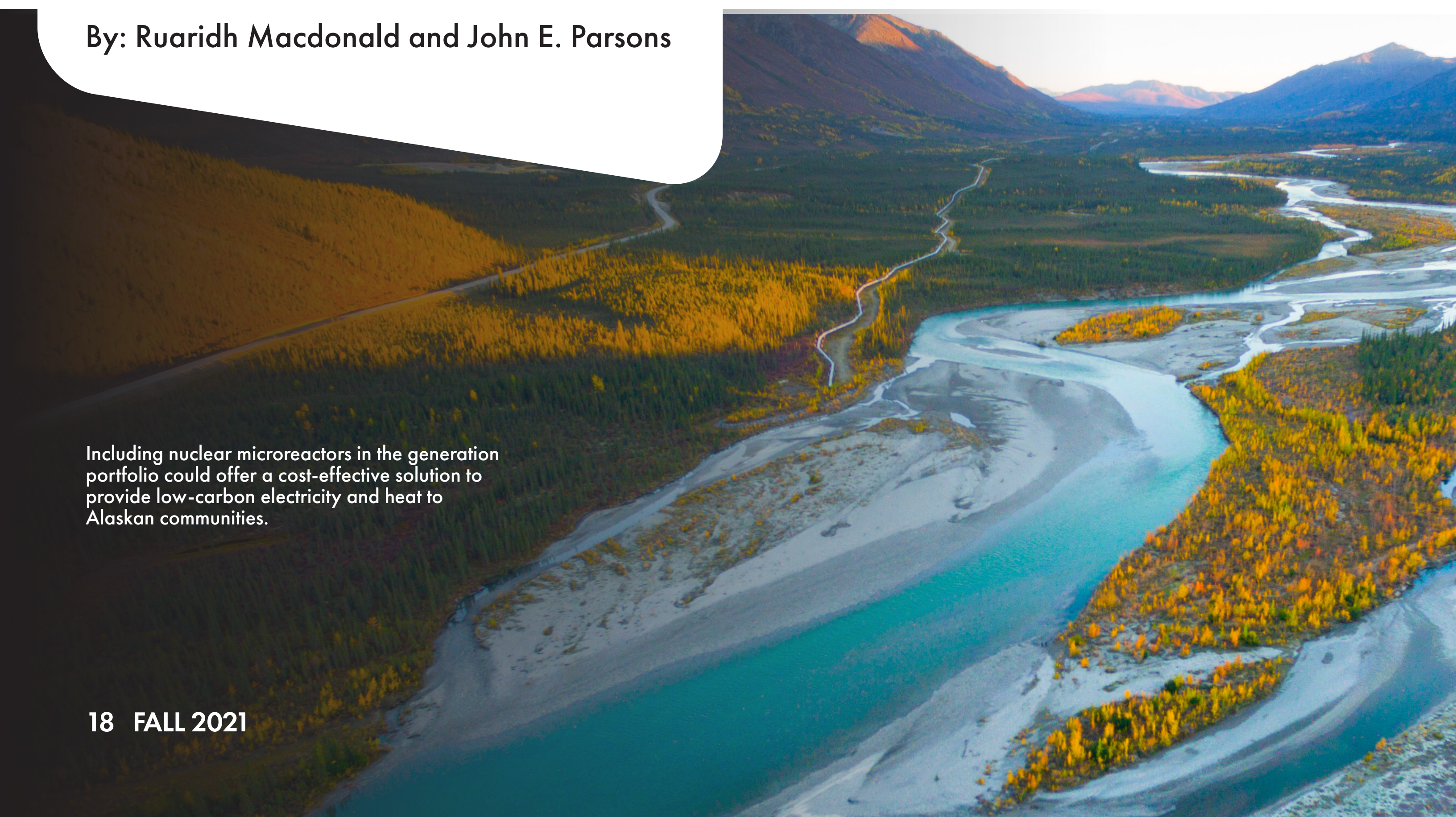
Nathan Delacrétaz, Bruno Lanz, and Jeremy van Dijk (2021), "Technology Adoption and Early Network Infrastructure Provision in the Market for Electric Vehicles", CEEPR WP-2021-015, MIT, October 2021.



Research.

The Value of Nuclear Microreactors in Providing Heat and Electricity to Alaskan Communities.

By: Ruaridh Macdonald and John E. Parsons



Including nuclear microreactors in the generation portfolio could offer a cost-effective solution to provide low-carbon electricity and heat to Alaskan communities.

We evaluated the system cost of providing electricity and heat to serve the load profiles of two types of Alaskan communities, and calculated the cost efficiency of including a nuclear microreactor in the generation portfolio. We employed a capacity expansion and dispatch model augmented to co-optimize heat and electricity generation. Since microreactor designs are still in development and the eventual capital costs are speculative, our strategy was to explore the outcomes across a wide range of capital costs, and find the range in which a microreactor is included in the least-cost portfolio and the range in which it is not. We call the boundary between the two the capital cost ceiling.

We have identified the microreactor capital cost ceiling under a range of assumptions and scenarios. This includes two different load profiles—one reflective of demand across Alaska's Railbelt communities, and one reflective of demand at a remote Alaskan mine and neighbouring community. We assessed the impact of natural gas fuel availability, whether a community had a district heating network, future reductions in the capital cost of renewables, the price of fossil fuels, and, last-but-not-least, the need to reduce systemwide emissions.

Three factors appear to play a dominant role in setting the capital cost ceiling and answering whether a microreactor is likely to be a cost-efficient addition to the system. One of these is the availability of natural gas. Natural gas is a much cheaper source of energy than diesel fuel, and therefore the microreactor capital cost ceiling is significantly lower in communities where it is available. Most communities in the Alaskan Railbelt have access to natural gas, while few, if any, of the other communities do.

The second factor is the size of the heat load and the accessibility of a district heating network. In our results, the capital cost ceiling was much higher in scenarios where a microreactor's waste heat was highly utilized. Communities in the Alaskan Railbelt have higher heat loads and select ones have accessible district heating networks, which facilitated the use of microreactor waste heat, and set the capital cost ceiling high. In contrast, a remote community anchored by a mine has a relatively smaller heat load, which would set the capital cost ceiling lower.

The third, and overwhelmingly most important factor, is the goal of emission reductions. Any modest emissions reduction target dramatically raised the capital cost ceiling for a microreactor, reflecting that the microreactor is very cost-efficient among low carbon options when heat and electricity are considered together. This conclusion holds broadly across both load profiles. We focused on CO_2 emissions. However, we are aware that certain Railbelt communities face a critical need to reduce particulates and other criteria pollutants. Recognizing this would further boost the competitiveness of a microreactor.

Community	Natural gas available?	CHP accessible?	No emission reduction target	25% emission reduction target
Railbelt community	Yes	No	$4,700/kWe	Not tested
		Yes	$8,300 /kWe	>$30,000/kWe
Mine & Remote community	No	No	$12,500/kWe	Not tested
		Yes	$12,500/kWe	>$30,000/kWe

Table 1. Summary results: microreactor capital cost ceiling for select scenarios. The capital cost ceiling is the highest overnight capital cost a microreactor can have while still being included in the least-cost generation portfolio. The microreactor variable cost was assumed to be $15/MWh-e. Diesel fuel was available in all scenarios for heating and electricity generation. Combined heat and power (CHP) accessibility refers to the whether waste and bypass heat from thermal electricity generators could be used to meet heat demand, and whether a district heating network existed to deliver that heat. The 25% emission reduction target considered emission from both electricity and heat generation.

Ruaridh Macdonald and John E. Parsons (2021), "The Value of Nuclear Microreactors in Providing Heat and Electricity to Alaskan Communities", CEEPR WP-2021-018, MIT, November 2021.

Research.

Electricity Price Distributions in Future Renewables-Dominant Power Grids and Policy Implications.

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

Tightening constraints on power system carbon emissions will make optimal increased reliance on variable renewable energy (VRE, mainly wind and solar generation), which has near zero marginal operating costs. Wholesale prices will be very low when VRE generation is on the margin. A CEEPR Working Paper by a team of authors from MIT and the Brattle Group uses capacity expansion modelling of Texas in 2050 to illustrate wholesale price distributions in future energy-only, carbon-constrained grids without price caps under a range of technology and system assumptions, as well as to study broader implications for cost recovery of investments in the power sector and for the design of retail electricity tariffs to support efficient economy-wide decarbonization via electrification.

To quantify impacts on wholesale electricity price distributions, the authors used the GenX capacity expansion model (CEM) to simulate deeply decarbonized electricity systems under a number of scenarios. GenX includes representation of various supply and demand-side resources, including energy storage with independent discharging and charging power capacities and energy storage capacity, demand flexibility, demand response, and use of hydrogen for non-electric end-uses. The case study evaluated using the GenX model is based on projected load and VRE resource availability in 2050 in Texas, which is represented as a single transmission zone with greenfield conditions reflecting the retirement of the existing fleet by 2050.

What the application of this model shows is that deeply decarbonized systems will have many more hours of very low wholesale prices – corresponding to periods of high VRE availability relative to load – and more hours of relatively high prices – approaching the value of lost load – than today. In decarbonized VRE-dominant energy-only wholesale power markets without price caps, generators and storage facilities will earn the bulk of their annual energy market revenues in relatively few hours compared to the situation today. Financial instruments to hedge price volatility will consequently be more costly. The presence of demand response, long-duration energy storage, dispatchable low-carbon generation, and flexible electricity-based hydrogen production weaken but do not reverse these results.

In the modeled systems, end consumers pay spot wholesale prices for electricity; these prices are much, much more variable than those any real customers now face. It is hard to imagine policy makers allowing these outcomes of our modeled systems to emerge in real systems as decarbonization proceeds. How they respond to those challenges will determine the costs of economy-wide decarbonization and perhaps even its feasibility. Most organized power markets already have caps on wholesale prices that are below reasonable estimates of the value of lost load, and such caps will almost certainly be present in decarbonizing systems with higher underlying price variability. Such caps reduce energy-market revenues and create the so-called "missing money problem" of sub-optimal incentives for investment in generation.

By reducing price variability, such caps will reduce energy arbitrage opportunities for storage facilities and, thus, also reduce incentives to invest in storage below efficient levels. Market designers have responded to the "missing money problem" by introducing a variety of supplemental capacity remuneration mechanisms, and these will be even more important in decarbonizing systems. These mechanisms were originally designed for systems dominated by dispatchable thermal generators, however, which have relatively predictable maximum outputs and marginal costs. These capacity remuneration mechanisms need fundamental modification to handle VRE generation, the outputs of which depend on the weather, which also affects demand. Storage facilities, which at any time can only supply the energy they have previously stored, pose more fundamental challenges to the design of capacity mechanisms.

Unlike the retail customers in the modeled systems, only a few customers (almost exclusively large commercial and industrial concerns) pay wholesale spot prices today. As those prices become more variable, it is hard to imagine regulators requiring more customers to pay them. The February, 2021 energy crisis in Texas, when a few retail customers who had signed up to pay wholesale spot prices received astronomical bills, has provided a strong push in the opposite direction. To encourage economy-wide decarbonization, however, it is essential that all consumers face low prices when wholesale spot prices – and thus the marginal social cost of electricity – are low. This requires that the costs of supplemental capacity remuneration mechanisms not be recovered by volumetric (per-kWh) charges as at present. These costs should be covered by customer-specific charges that are fixed in the short run but respond to long-run demand patterns and that vary among customers in a politically acceptable way.

At the other end of the price distribution, efficiency requires that the demand for electricity be reduced when its wholesale price is high, most plausibly by shifting demand to other periods. Efficiency does not require that households and small businesses actually pay high wholesale prices, however. As the authors contend, the most viable solution may be for local distribution companies or other intermediaries to contract with small customers to supply electricity at relatively predictable prices in exchange for automated, price-responsive control of vehicle charging, HVAC systems, appliances, and other flexible loads. With such automated control of demand via demand response contracts, the risks of price volatility faced by retail customers can be mitigated without sacrificing efficiency.

Dharik S. Mallapragada, Cristian Junge, Cathy Wang, Hannes Pfeifenberger, Paul L. Joskow, and Richard Schmalensee (2021), "Electricity Price Distributions in Future Renewables-Dominant Power Grids and Policy Implications", CEEPR WP-2021-017, MIT, November 2021.



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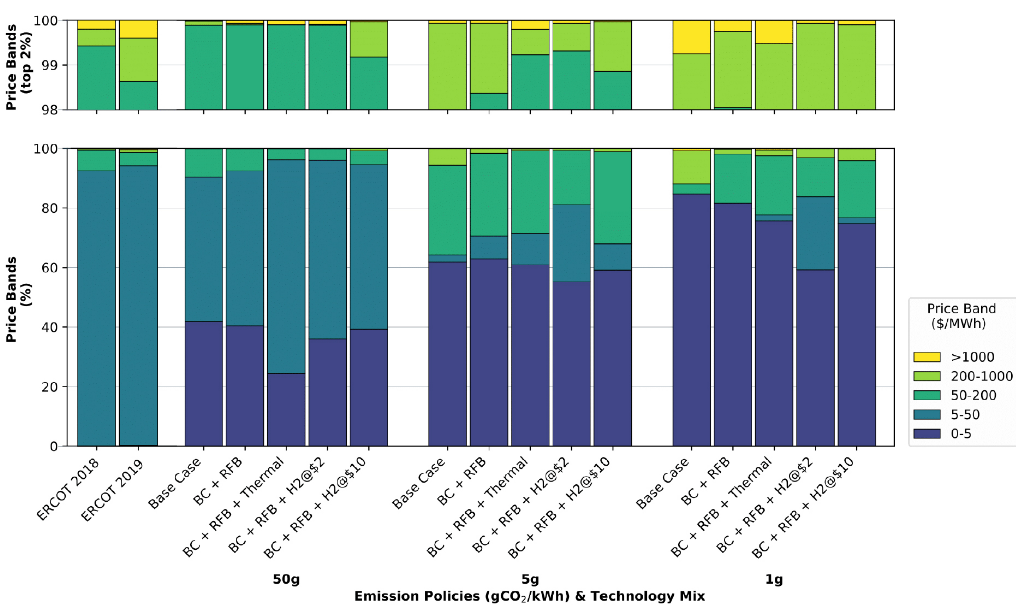

Figure 1. Impact of storage technology, external H_2 demand as well as the price of non-power H_2 supply on the distribution of electricity prices for various CO_2 emissions constraints.

For comparison, wholesale energy price distributions from ERCOT in 2018 and 2019 are also shown. Base case corresponds to Li-ion as the sole energy storage technology and no external H_2 demand.

BC = Base Case.
RFB = Redox Flow Battery.

Research.

Advancing International Cooperation under the Paris Agreement: Issues and Options for Article 6.

By: Michael A. Mehling

Article 6 of the Paris Agreement enables Parties to engage in voluntary cooperation as they implement their nationally determined contributions (NDCs). Specifically, Article 6 sets out three pathways for voluntary cooperation:

- cooperative approaches through the use of internationally transferred mitigation outcomes (ITMOs) in Article 6.2;
- a new crediting mechanism, sometimes referred to as the "Sustainable Development Mechanism", in Article 6.4; and
- a framework for non-market approaches in Article 6.8.

Although Article 6 omits explicit reference to carbon markets, it firmly anchors market mechanisms in the Paris Agreement with the two options set out in Article 6.2 and 6.4, and thereby leverages the promise of such mechanisms to lower the cost of achieving agreed climate policy outcomes. A recent study suggests that the compliance flexibility introduced by Article 6 can reduce the overall costs of mitigation under currently submitted NDCs by approximately US$ 300 billion per year in 2030, echoing earlier estimates of savings of similar magnitude. Such cost reductions, in turn, can increase the latitude of countries to scale up global climate ambition by unlocking additional resources that can be diverted to mitigation activities. Calculations of the additional mitigation achievable by reinvesting avoided cost are, again, staggering, and would roughly allow doubling already pledged emission reductions annually through 2030.

Given the substantial shortfall between currently pledged NDCs and the ambition required to achieve the temperature stabilization targets of the Paris Agreement, international cooperation under Article 6 has been described as a necessary 'tool to promote more mitigation action ... and pave the way for progress within the next NDC cycle.' Critics have countered that Article 6 could weaken ambition under the Paris

Agreement if it lacks sufficient integrity or creates a distorted incentive for future NDCs. With a recent synthesis report of NDCs confirming that a majority of Parties intends to use Article 6 as a source of climate finance or as a means to achieve pledged emission reductions, the stakes for Article 6 are high.

Importantly, however, the treaty provision that constitutes Article 6 in the Paris Agreement is sparsely worded and replete with vague concepts. Such 'constructive ambiguity' – often a deliberate choice to accommodate conflicting viewpoints – can compromise implementation of Article 6 by leaving room for divergent interpretations of key operational elements and creating uncertainty. Parties have therefore been engaged in developing rules and guidance for implementation of Article 6 since adoption of the Paris Agreement. Just as Article 6 was the last provision Parties agreed upon when the Paris Agreement was adopted, however, its operationalization continues to defy a negotiated outcome.

In the decision formally adopting the Paris Agreement and several provisions of the treaty itself, Parties set out mandates to elaborate decisions with operational details on a broad set of issues ranging from mitigation and adaptation to transparency, accounting, compliance, and assessment of progress. Scheduled to conclude during the Meeting of the Parties to the Paris Agreement (CMA) in December 2018 in Katowice, Poland, this process – formally known as the 'Work Program under the Paris Agreement' (PAWP) – resulted in a comprehensive set of decisions that are colloquially referred to as the 'Paris Rulebook.' One agenda item in this work program has eluded consensus so far, however: the operational details of Article 6.

Working through the Subsidiary Body for Scientific and Technical Advice (SBSTA), Parties have been locked for half a decade in negotiations on decisions that provide guidance on cooperative approaches under Article 6.2 and elaborate rules, modalities, and procedures for Article 6.4. Over this period, delegates have debated a succession of formal and informal texts of varying length, detail, and maturity, with numerous options and extensive bracketed text revealing the heterogeneity of views across Parties. Despite going into overtime during both COP24 in Katowice and COP25 in Madrid, Parties failed to bridge their differences on several key issues in the operationalization of Article 6, ultimately mandating SBSTA to build on existing progress and elaborate new recommendations for adoption during COP26 in Glasgow.

Following an unprecedented hiatus in the climate negotiations due to the global pandemic caused by the novel coronavirus, Parties have scrambled to make up for lost time, yet a successful outcome at the Glasgow summit remains far from guaranteed. Discussions resumed in the second half of 2020, but remained informal, hampered by the virtual format. Despite a constructive series of multilateral consultations with Heads of Delegation (HoDs) and coordinators of regional negotiating groups convened by the COP25 and COP26 Presidencies, and informal technical expert dialogues hosted by the SBSTA Chair, apparent progress in 2021 has remained slow. Reviewing the outcomes of informal ministerial consultations in July 2021, the facilitators of those meetings warned that 'progress on Article 6 was well behind time, and any further delays on a deal in Glasgow on Article 6 might erode ambition, transparency, accountability, and support.'

Parties have consistently identified a limited number of issues in the Article 6 negotiations that remained unresolved at the end of COP25. Among the most contested are:

- Accounting for Article 6.4 reductions generated outside the scope of host Party NDCs;
- generating finance from Article 6.2 to support adaptation action (share of proceeds);
- transitioning unused emission units generated before 2020 to meet NDC targets;
- ensuring overall mitigation in global emissions (OMGE) under Article 6.2; and
- baseline setting and additionality determination under the Article 6.4 mechanism.

Each of these critical issues is described in greater detail in the Working Paper, with a discussion of the substantive issues, the contending positions of key Parties and negotiating groups, and potential 'bridging options' that could enable a compromise outcome. On each issue, draft decision language proposed by the COP25 Presidency during the final day of negotiations in Madrid is included for reference, although it neither represented a consensus of views at the time, nor necessarily offers the most likely starting point for formal negotiations during COP26. Still, it provides a sense of what the COP25 Presidency considered possible 'landing zones' for compromise on key issues during the last formal Meeting of the Parties before the COVID-19 pandemic, and has been frequently cited by Parties in their submissions and statements since.

Past negotiations have repeatedly shown that 'nothing is agreed until everything is agreed', meaning that an agreed outcome will often emerge as a result of mutual concessions and arrangements. How that process unfolds, and which Parties will be willing to relent on one or more concerns in return for accommodation of their central priorities, is often unpredictable. Still, the survey of stated positions provided in this discussion paper can serve as a helpful starting point to understand the interests and motivations of those actors whose agreement will be necessary to arrive at a workable compromise in Glasgow. With insufficient time to reset negotiations and begin the process afresh, these views and the deliberations in which they have been expressed – including the latest round of informal technical expert dialogues facilitated by SBSTA in September and October 2021 – provide a vital milepost for delegates to resume where they left off at COP25.

Ultimately, If the aspiration of Article 6 – according to its wording – is to 'allow for higher ambition in mitigation and adaptation actions', then lacking uptake could impede more ambitious pledges. For that aspiration to be realized, however, Article 6 has to secure a high standard of environmental integrity. Experience with earlier carbon markets leaves little doubt that robust governance, both at the multilateral level and in the bilateral arrangements between Parties, will be critical for the enduring viability of Article 6. If its operationalization is unable to ensure alignment with the temperature stabilization goals of the Paris Agreement, it will only be a matter of time before confidence in the market dwindles, as it already did once under the Kyoto Protocol.

From left to right:
Robert C. Stowe and Robert N. Stavins, Harvard University; Daniele Agostini, Enel Group; Martin Hession, European Commission; and Michael Mehling, MIT CEEPR.
Photo by: Doug Gavel

A recording of this session at COP26, "Securing Climate Ambition with Cooperative Approaches: Options under Article 6" can be viewed here: https://www.youtube.com/watch?v=3i4o7vy5jvU

Michael A. Mehling (2021), "Advancing International Cooperation under the Paris Agreement: Issues and Options for Article 6", CEEPR WP-2021-016, MIT, November 2021.

That does not, however, mean that negotiators should always err on the side of the most ambitious option for each issue currently under discussion. While the 'San José Principles for High Ambition and Integrity in International Carbon Markets' may have commendable intentions, for instance, some of the principles, if interpreted and applied literally, could effectively prevent Article 6 from fulfilling its potential to enable ambition by lowering the cost of achieving mitigation targets. A balance between stringency and flexibility is therefore essential.

Still, whether Parties at COP26 can overcome their past divisions to achieve a balanced outcome is everything but certain. With all other elements of the 'Paris Rulebook' finalized, concerns and preferences that Parties were willing to set aside in the interest of a successful result in Katowice, including deeply held views about the nature and objectives of the Paris Agreement, risk being drawn to the surface during negotiations on Article 6. Already, as the analysis in this discussion paper has shown, Parties are alternatingly invoking specific provisions of the Paris Agreement and general principles and objectives to justify their position, echoing the recursive argumentation patterns of international relations more generally. Yet agreement is not altogether out of reach. Despite the long hiatus in formal negotiations occasioned by the global coronavirus pandemic, Parties have not remained idle. As they reconvene, they will be equipped with both a better understanding of the implications of alternative policy choices, and a better sense of the viewpoints and positions of their fellow Parties. Improved knowledge may, in the end, be the key to unlock the transformational potential of Article 6 in Glasgow.

Research.

Studying User Experiences of Distributed Energy Storage Resources in Texas.

By: Caroline White-Nockleby

In July 2021, I took a research trip to Austin, Texas, sponsored by CEEPR, to learn about household experiences during Winter Storm Uri. This storm broke temperature records across the North American continent in mid-February. It also triggered widespread power outages most dramatically in Texas, where an estimated 4.5 million households were affected, in some cases for over three days.

Much research on the outages has offered crucial documentation of the storm's devastating impacts on low- and moderate-income households. Informed by this research, I wanted to learn about the experience of those households that *did* have access to energy resources during the storm. How did households use such resources? How helpful were they, and what factors determined their usefulness? What insights might the experiences of this unique group offer?

To explore these questions, I interviewed 15 Austin-based individuals who maintained access electricity when the power went out, largely via residential batteries or electric vehicles. These individuals are not a representative sample of the city: nearly all self-identified as middle- or high-income. All cited concern about climate change as a key motivation for becoming an EV or battery owner. More than one also told me they loved to "geek out" on the technical intricacies of their home energy installations. Below, I share a few preliminary insights from the trip.

Though owning batteries can increase energy use awareness, during the blackout, effective battery back-up sometimes made individuals less aware of unfolding events.

Because batteries buffer supply intermittencies, in some cases those I spoke to were unaware when the power had gone out in their neighborhood. "It's so instantaneous...you almost don't notice it," as Melissa, a technical program manager, described the switch from grid to backup power, "[The flicker of the lights] is like you're blinking."

Eileen, another battery owner, at the start of the storm was in touch with neighbors via the Next Door app. At first, "There [was] a lot of chatter about the weather- and then it got really quiet. And I didn't realize it got quiet because everybody [had] lost power." As she explained, "I felt really, really guilty about it when I figured out how long they had gone without power. And I'm just sitting there watching TV and baking cookies, you know what I mean? Like, really?"

Many I spoke with shared water or power with neighbors; others invited neighbors to stay in their house or used their EVs to distribute supplies to strangers in need. But not all neighbors took interviewees up on their offers, and those I spoke to didn't have capacity to help everyone. "However [my neighbors] managed, I don't know," Bill, an electrical engineer, told me.

Electric vehicle owners used their cars in creative ways, but also faced challenges.

Larry, a musician, put a small bed in the back of his car, where he slept during the storm. Others used their EV to charge phones or download videos for their children. But EV owners also faced limitations. Some did not have enough advanced notice to charge their cars beforehand.

Many wished they had been able to charge laptops, but could not because their EV had only USB ports.

Sarah, a science writer, did not know that her Tesla had a "camping mode" until she found out from a group text. This information made a huge difference: her family was able to spend time in the car to get warm, use WiFi, and watch TV. "It was pretty amazing," she recalled, "it was like having an office in your garage…. That changed everything."

In the wake of the storm, interviewees grappled with how to assess both the value and ethics of their storage resources.

As Rick, a retired military officer, told me, "How would you quantify the fact that we got to live comfortably for that week? I don't think you can… For us to be able to live without shivering in our house…To me that is one of those commercials [that describe activities as] 'priceless.' I mean, it sounds stupid: to be able to use [power] normally is priceless? But when everybody else can't, then it is."

Interviewees also reflected on the ethics of using residential batteries. Though during outages, they could not share power with neighbors, between outages their batteries allowed them avoid straining the grid by paring down their demand. As Ted, an engineer convinced by his storm experience to install a DIY battery system, explained, "the ability to store [energy] and defer its usage to alleviate the collective grid burden… not to mention the whole emergency preparedness aspect… seems like a dual benefit situation."

Yet many I spoke to argued that batteries, because of their expense and technical complexity, were not a tenable widespread solution to climate resilience – at least when installed at the residential scale. "[People] shouldn't have to spend money today in our in our society to back up their own power," Bill, the electrical engineer, told me. "They shouldn't have to go buy a generator. They shouldn't have to buy a solar panel and a big battery… They shouldn't have to do that."

Despite these misgivings, though, many interviewees did plan to expand their private storage capacity by buying more batteries, or by investing in EVs designed to double as back-up storage. "Realistically, you have to fend for yourself," Drew, a real estate agent, told me. Reflecting on her experience during the blackout, Louise, an environmental consultant, said, "It's just made me love [my EV] even more. I accidentally scraped it the other day, and I still feel bad about it. It's taken on a personality for me."

Next steps

These interviews form preliminary research for my dissertation project, which examines evolving stakeholder conversations about how to conceptualize, regulate, and utilize energy storage technologies. As an anthropologist in MIT's program in History; Anthropology; Science, Technology, and Society (HASTS), I use qualitative research to better understand individual perspectives and experiences. I believe such research might help guide policymaking, public education, and other social elements of energy transitions.

*All names have been changed to protect interviewees' privacy.

Caroline White-Nockleby is a Ph.D student in the MIT Program in History, Anthropology, and Science, Technology, and Society (HASTS) and is also a 2021-22 Energy Fellow with the MIT Energy Initiative. At MIT HASTS, her dissertation examines the relationships between policymaking, social dynamics, and technological innovations in the sourcing, manufacture, and implementation of energy storage technologies.

Events.

Fall 2021 webinars:

October 6, 2021
Small (and Modular) is Beautiful: The Future of Nuclear?
Christopher Colbert (NuScale Power) and Jacopo Buongiorno (MIT)

November 10, 2021
Applying Machine Learning to Energy Policy Research
Erica Myers (University of Calgary) and Christopher Knittel (MIT)

November 29, 2021
The Roosevelt Project: 4 Case Studies on the Energy Transition
Ernest Moniz (MIT), Christopher Knittel (MIT), David Foster (MIT), Stephen Ansolabehere (Harvard), Valerie Karplus (Carnegie Mellon), Jason Beckfield (Harvard), and Melanie Kenderdine (EFI)

December 1, 2021
Industrial Decarbonization: The Energy Challenge
Emre Gençer (MIT) and Dan Seligman (Ceres)

Recordings and slides from CEEPR webinars and events are available for Associates on our website at:

ceepr.mit.edu/events/webinars/
ceepr.mit.edu/events/research-workshops/

Upcoming webinars:

January 26, 2022
Roundtable: Climate Policy Between State and Federal Level

February 2, 2022
Investing in Infrastructure for the Energy Transition

February 23, 2022
The Economics of Plug-in Hybrid Electric Vehicles

Spring 2022 MIT CEEPR Research Workshop

May 12-13, 2022
Royal Sonesta Cambridge Hotel
Cambridge, MA

Invitations and agenda topics will be sent out in early 2022

Publications.

Recent Working Papers:

WP-2021-018
The Value of Nuclear Microreactors in Providing Heat and Electricity to Alaskan Communities
Ruaridh Macdonald and John E. Parsons, November 2021

WP-2021-017
Electricity Price Distributions in Future Renewables-Dominant Power Grids and Policy Implications
Dharik S. Mallapragada, Cristian Junge, Cathy Wang, Hannes Pfeifenberger, Paul L. Joskow, and Richard Schmalensee, November 2021

WP-2021-016
Advancing International Cooperation under the Paris Agreement: Issues and Options for Article 6
Michael A. Mehling, November 2021

WP-2021-015
Technology Adoption and Early Network Infrastructure Provision in the Market for Electric Vehicles
Nathan Delacrétaz, Bruno Lanz, and Jeremy van Dijk, October 2021

WP-2021-014
Policies for Electrifying the Light-Duty Vehicle Fleet in the United States
Cassandra Cole, Michael Droste, Christopher R. Knittel, Shanjun Li, and James H. Stock, September 2021

WP-2021-013
Intermittent versus Dispatchable Power Sources: An Integrated Competitive Assessment
Gunther Glenk and Stefan Reichelstein, August 2021

WP-2020-012
Water for a Warming Climate: A Feasibility Study of Repurposing Diablo Canyon Nuclear Power Plant for Desalination
Andrew T. Bouma, Quantum J. Wei, John E. Parsons, Jacopo Buongiorno, and John H. Lienhard V, July 2021

WP-2020-011
Challenges and Opportunities for Decarbonizing Power Systems in the US Midcontinent
Pablo Duenas-Martinez, Karen Tapia-Ahumada, Joshua Hodge, Raanan Miller, and John E. Parsons, July 2021

WP-2021-010
A Domestic Content Rule for Electric Vehicle Lithium-Ion Batteries Will Protect U.S. Jobs
Amelia Pedone and John Deutch, July 2021

WP-2021-009
Facilitating Transmission Expansion to Support Efficient Decarbonization of the Electricity Sector
Paul L. Joskow, June 2021

WP-2021-008
From Hierarchies to Markets and Partially Back Again in Electricity: Responding to Deep Decarbonization Commitments and Security of Supply Criteria
Paul L. Joskow, June 2021

WP-2021-007
Energy Conversion and Storage: The Value of Reversible Power-to-Gas Systems
Gunther Glenk and Stefan Reichelstein, May 2021

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

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