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Alternative transportation fuels

Energy Transition Metals

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Martin Stuermer

Abstract

The energy transition requires substantial amounts of metals such as copper, nickel, cobalt and lithium. Are these metals a key bottleneck? We identify metal-specific demand shocks, estimate supply elasticities and pin down the price impact of the energy transition in a structural scenario analysis. Metal

prices would reach historical peaks for an unprecedented, sustained period in a net zero emissions scenario. The total value of metals production would rise more than four-fold for the period 2021 to 2040, rivaling the total value of crude oil production. The cost of metals are a potentially important input into integrated assessments models of climate change and the energy transition.

Methods

This paper quantifies the impact of the clean energy transition on metals prices. Metals such as copper, nickel, cobalt, and lithium are key building blocks for the clean energy transition (International Energy Agency, 2021; World Bank, 2020). For example, an electric car requires five times more of these metals than a conventional car. The global economy may therefore become more metals intensive, as the use of fossil fuels potentially declines. However, this raises concerns that metals supply might not catch up with a soaring demand, inducing an increase in the cost of metals as inputs, and, thus, potentially delaying the energy transition.

We model the potential impact of the energy transition on metals prices as a sequence of metals-specific demand shocks in separate structural VAR models for cobalt, copper, lithium and nickel. To distinguish metal-specific demand shocks from aggregate commodity demand shocks, we propose a novel identification strategy: We augment the standard three-variables commodity market model (e.g., Kilian, 2009; Baumeister and Peersman, 2021; Jacks and Stuermer, 2020, and others) by an ``anchor'' variable.

More precisely, each structural VAR model includes four endogenous variables, namely a measure of global economic activity, the global production of the respective metal, its real price and the anchor variable. In our case, the anchor variable is an additional commodity price (e.g., for cotton), which we assume to be affected by aggregate commodity demand shocks but not by metal-specific demand shocks on impact. For example, an unexpected increase in aggregate commodity demand due to a booming global economy would raise prices for both lithium and cotton. In contrast, an unexpected increase in lithium demand for batteries (a positive lithium-specific demand shock), drives up the lithium price but not the price for cotton on impact. This identification relies on the assumption that the anchor variable (e.g., cotton) is not a substitute for the analyzed metal (e.g., lithium). Finally, the exclusion restrictions imposed on the anchor variable are complemented by traditional and narrative sign restrictions (Antolin-Diaz et al 2018).

In modelling the energy transition, we take metal consumption scenarios from the International Energy Agency (2021) as given, assuming that global consumption equals production over the long-term. We use a structural scenario analysis following Antolin-Diaz et al (2021) to derive a sequence of exogenous metal-specific demand shocks that match the global metal consumption scenarios. In other words, the algorithm finds a series of these shocks that incentivizes the metal output path needed for the energy transition. We then derive the implied price and revenue paths.

The structural scenario analysis allows us to deal with the limits of reduced-form conditional forecasts from VAR models, namely that a missing causal mechanism confounds the interpretation. The methodology has the advantage that it can distinguish among structural shocks (such as aggregate demand, commodity-specific demand, and supply shocks), which may have substantially different implications for the price.

Results

We find that the four metals are a potential bottleneck for the energy transition. Metal prices would reach historical peaks for an unprecedented, sustained period of roughly a decade in the net zero emissions scenario. This would imply that prices of nickel, cobalt and lithium would rise several hundred percent from 2020 levels, while copper would increase more than 60 percent. In the IEA's stated policy scenario prices for all four metals would broadly stay in the 2020 range.

We estimate that the energy transition could provide significant windfalls to metals producing firms' and countries. In the Net-Zero scenario, the demand boom could lead to a more than fourfold increase in the value of metals production—totaling US$ 13 trillion accumulated over the next two decades for the four "energy transition" metals alone, providing significant windfalls to commodity producers. This could rival the estimated value of oil production.

Results also show that metal supply is quite inelastic over the short term but more elastic over the long term. A metal-specific positive demand shock to price of 10 percent increases the same-year output of copper by 3.5 percent, nickel by 7.1 percent, cobalt by 3.2 percent and lithium by 16.9 percent. After 20 years, the same price shock raises output of copper by 7.5 percent, nickel by 13.0 percent, cobalt by 8.6 percent and lithium by 25.5 percent. This evidence is in the range of other studies in the cases of copper and nickel, but substantially higher for cobalt in the long run (see review in Dahl (2020) and Fally and Sayre (2018).

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Carbon emissions reduction

Electrification and Decarbonization Goals in Power Sector: MARKAL scenarios analysis

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Abstract

The U.S. end use sectors (commercial, industrial, residential, and transportation) almost doubled their energy use in 1949 -2020 and in 2020 the industrial sector accounted for the largest share of energy use (33 %), followed by transportation (26 %). In the search for solutions to mitigate climate change, the industry and transportation are most challenging sectors to decarbonize. In our study, we use MARKAL model to quantify effects of measures for energy system CO2 emissions in order to simulate plausible scenarios for curbing emissions in the U.S. in 2015-2075. We consider the following scenarios: reference, end use sectors electrification, zero CO2 emissions in power sector goal by 2035 and end use sectors electrification with zero CO2 emissions in power sector goal by 2035.

Our modeling results show that in the end use sectors electrification scenario, CO2 emissions into the atmosphere (4,102 Mt CO2) are reduced by about 24% in comparison to the reference scenario (5,399 Mt CO2) by 2075. When net zero CO2 emissions in power sector goal is implemented in the scenario, the emissions (4,093 Mt CO2) are reduced also by 24% in comparison to the reference scenario. Cumulative CO2 emissions in net zero CO2 emissions power sector goal scenario are 20% lower than in reference scenario and cumulative CO2 in end use sectors electrification scenario are 13% lower by 2075. The highest level of total energy system decarbonization by 2075 is in the scenario of end use sector electrification with zero CO2 power sector goal (997 Mt CO2). CO2 emissions in this scenario are 82% below reference level and cumulative CO2 emissions are 147% lower than in reference scenario by 2075.

The study shows that in end use sectors electrification scenario, major contributions of decarbonization is in transportation sector that is electrified easier than all other sectors. Industry decarbonization can come from the further uptake of secondary steel production, but industrial decarbonization needs stronger CO2 constraints for deployment industrial Carbon Capture, Utilization and Storage (CCUS) and/or fuel switch to hydrogen. Results show that net zero CO2 power sector by 2035 goal drives the decarbonization process but is not sufficient on its own in order to reach net zero CO2 in whole energy sector by 2050.

In addition, the uptake of innovative low-carbon breakthrough technologies is necessary. It is concluded that industrial electrification is counterproductive for climate change mitigation if electricity is not provided by low-carbon sources. Overall, fuel switching, end use sectors electrification, and power sector decarbonization goal as single measures have a limited decarbonization impact, compared to an integrated approach that implements all the measures together providing a much more attractive solution for CO2 mitigation.

Using the MARKAL model we assessed how electrification-driven changes and net zero CO2 emissions in power sector goal could impact the future of the power system. Scenario results include projected changes to the U.S. power system, use of that infrastructure, and impacts related to the broader energy system.

Methods

MARKet ALlocation (MARKAL) is an integrated energy systems modeling platform that can be used to analyze energy, economic, and environmental issues at the global, national, and municipal level over several decades. MARKAL is a bottom-up, dynamic, linear programming optimization model created to find cost-optimal pathways under different scenarios constraints within the context of the entire energy system. MARKAL represents energy imports and exports, domestic production of fuels, fuel processing, infrastructures, secondary energy carriers, end-use technologies, and energy service demands of the entire economy. MARKAL does not contain an in-built database, so the user is obliged to enter input parameters. In this study, the publicly available EPAUS9r2017 database for the U.S. energy system (with the U.S. Census regions represented) had been adopted and modified.

Each of the 9 regions the U.S. Census regions was modeled as an independent energy system with different regional costs, resource availability, existing capacity, and end-use demands for 2015-2075. Regions are connected through a trade network that allows transmission of electricity and transport of gas and fuels. Electricity transmission is constrained to reflect existing regional connections between North American Electric Reliability Corporation (NERC) regions as closely as possible.

Table 1. Scenario Definitions

Scenario Name	Scenario Definition	Policy availability
Reference	AEO 2018 reference	None
ReferenceELC	End use sectors electrification	None

NetZero2035 Reference, power sector decarbonization Power Net zero CO_2 2035

NetZero2035ELC Electrification, power sector decarbonization Power Net zero CO_2 2035

Results

From the scenarios modeled, six key findings emerged.

1. End use sectors electrification drives the deployment of renewable energy and natural gas generators in all regions of the U.S. Generation from renewable energy increases in all scenarios and, in the absence of carbon policies, new natural-gas-fired generation is also built to meet electrified loads. To meet electricity demand in high-electrification scenario with CO_2 constraint, installed capacity grows to more than double 2015 levels by 2075. Which source supplies more electricity will largely depend on the future prices of renewable technologies, CCUS technologies, and natural gas price.
2. In the scenarios with net zero CO_2 emissions goals in power sector by 2035, regional resources are increasingly relied upon to meet electrification-driven load growth, which mitigates the influence of electrification on the need for additional long-distance, interregional transmission expansion.
3. There are plentiful resources in the U.S. to meet potential electrification-driven growth in electricity demand. Low-cost renewable energy resources and natural gas are available in all regions of the U.S. in the absence of new policies. However, this electrification has only a modest effect on the cost of electricity in the scenario without CO_2 goals.
4. The system cost impact of electrification on the entire energy sector depends strongly on future advancements in the cost and efficiency of electric end-use technologies. Electric-sector system costs increase with the additional generation and transmission capacity that is needed to serve the growing load under widespread electrification. Though, these costs are partially or entirely offset by fuel and operational savings in the buildings, transportation, and industry demand sectors. Thus, end use electrification with rapid cost and performance improvements in the can result in cumulative net energy system savings — up to US$40 billion in the end use sectors electrification scenario in 2015-2075.
5. Widespread electrification leads to reductions in direct energy consumption and emissions from the energy system, due to the improved efficiency of electric end-use technologies and declining emissions intensities associated with electricity generation. Building sector electrification results in higher electricity consumption in commercial sector and lower electricity consumption in residential sector.
6. In the electrification of end use sectors scenario, energy savings and CO_2 emissions reductions are largely driven by electrification in the transportation sector. The level of emissions reductions that could be achieved depend strongly on the future generation mix, but CO2 emissions decline in all scenarios examined.

References

1. Industrial decarbonization is crucial to mitigate climate change. Multiple measures, such as industrial electrification, fuel switching (including switching to hydrogen), and CCUS, can be

adopted to reach this goal. The study shows that CCUS is not implemented in industrial facilities without strong policy support or commercial incentives.

1. To make increased electrification effective, it is pivotal to decarbonize the power sector. While there is an economic barrier for the uptake of CCUS technologies, an economic incentive, such as a carbon tax, carbon reductions goals for whole energy system are necessary for shifting the fuel supply towards lower-carbon fuels. Moreover, carbon constraints drive investors to invest in plants with integrated CCUS, especially for CO_2 intensive technologies. The deployment of CCUS goes beyond the emission reductions from fuel switching and electrification, and Biomass with Carbon Capture and Storage (BECCS) is pivotal for decreasing the amount of CO_2 as the only technology with negative CO_2 emissions.
2. Each of the analyzed scenarios has limited impact on reaching ambitious climate goals. An integrated approach is needed for sufficient CO_2 reduction. Overall, while the case study of this work shows that a carbon goal in power sector to decarbonize electricity generation is essential, it also shows that additional efforts are crucial for the deep decarbonization that is necessary to reach climate targets such as the Paris Agreement. The uptake of innovative breakthrough technologies such as Direct Air Capture (DAC) is necessary.

45Q Tax Credit Impacts on Carbon Management Costs: Case Study Findings and Modeling Developments

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Abstract

Carbon capture and storage (CCS) is one emerging strategy to manage or reduce carbon dioxide (CO_2) emissions in the atmosphere. Carbon management costs, from a CO_2 source's perspective, include the costs of CO_2 capture, transport, and storage. A CCS finance gap, relative to non-CCS scenarios, exists if carbon management costs cannot be completely offset by additional revenue, tax credits, penalty avoidance, and/or other financial incentives. The Section 45Q carbon oxide sequestration tax credit (45Q) is a federal general business tax credit that provides a performance-based financial incentive for CO_2 capture projects that ensure CO_2 storage. For CCS networks that would rely on secure CO_2 storage in saline aquifers (saline storage), 45Q represents a critical offset to carbon management costs. The National Energy Technology Laboratory (NETL) completed initial work to reasonably assess 45Q's impact on carbon management costs for CO_2 sources that would utilize saline storage. This work has led to further analysis and model development to enhance understanding of this area. NETL's assessments demonstrate that, for the scenarios modeled, 45Q as enacted lowers carbon management costs for eligible CCS projects but does not close the CCS finance gap. Also, tax equity partnerships are required to optimize 45Q tax credit monetization, resulting in some dilution of 45Q tax credit face value from the CO_2 source's perspective. NETL is developing a model that considers the financial complexity of tax equity partnerships to help researchers, policy makers, taxpayers, and other stakeholders better assess and understand 45Q impacts on carbon management costs.

Disclaimer:

Methods

NETL resources and models were used to assess the impact of 45Q on saline storage CCS network scenarios in the central United States (U.S.) from a CO_2 source's perspective. Optimal 45Q monetization was modeled assuming a combination of self-sheltering credits at the CO_2 source, transferring credits to the storage company, and allocating credits to investors using a tax equity partnership. NETL also assessed the financial impact of additional hypothetical carbon management policies, such as a per unit levy on CO_2 emissions based on social cost of carbon estimates. Both studies assessed a variety of CO_2 sources, including coal-fired power plants, natural gas combined cycle power plants, and cement manufacturing plants. NETL is developing a 45Q Tax Credit Monetization Model (45Q Model) that incorporates the finances of both capture and storage companies. This model considers the Internal Revenue Service and U.S. Treasury regulations and guidance on 45Q and tax equity partnerships. The 45Q Model will enable a more robust approach for evaluating the impact of the 45Q tax credit for CO_2 sources interested in capturing and storing CO_2. When complete, the model will assess the amount of subsidy (equivalent to the financial gap) required to make uneconomic scenarios economical. The 45Q

Model will demonstrate how 45Q value is distributed and monetized among capture, storage, and tax equity investor participants in a tax equity partnership.

Results

45Q tax credits, as enacted, with a face value of $50 per metric ton (in 2026 dollars) of CO_2 (/tCO_2) captured for saline storage, lowered CO_2 management costs in the CCS scenarios modeled in both case studies by $29 to $34/t$CO_2$. 45Q value to the CO_2 source is diluted below its face value because the tax credit's 12-year eligibility duration is shorter than the CCS networks' modeled 30-year project lifespans. 45Q value is further diluted below its face value from the source's perspective due to tax equity partnership involvement required to optimally monetize the non-refundable tax credits. These initial 45Q impact estimates did not incorporate monetization of ancillary tax benefits such as asset depreciation and negative income. Preliminary results from the 45Q Tax Credit Monetization Model (under development), which incorporates ancillary tax benefits, estimated 45Q would lower CO_2 management costs by $42 per metric ton (in 2026 dollars). In all scenarios assessed, 45Q as enacted did not itself close the CCS finance gap, even with carbon emission penalties.

CCUS: Surveying Where We Have Been and Where We Are Going: Projects, Policies, Progress and Price

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Abstract

With rising ferocity and frequency of extreme weather and ecological events (e.g., droughts, hurricanes, floods, rising sea, dying coral reefs), climate change no longer seems a figment of climate scientist's imaginations and models. Rather it is here and now, and many are considering how to limit global temperature increase to less than 1.5°C as set in the Paris Agreement in 2015 (Delbeke et al., 2019). Most long-term scenarios see a role for CCUS (National Petroleum Council, 2019). For example, IEA argues that to meet the Paris Agreement, 1/5 of industrial CO2 emissions will have to be sequestered by 2060, amounting to 28 gigatonnes (IEA, 2019). Although much effort has been expended on its technical feasibility and cost, very little carbon and other greenhouse gases have been sequestered. Around 32 billion metric tonnes of CO2 were emitted from fossil fuel combustion in 2020 whereas only an estimated 40 million metric tons were captured and sequestered in 2019 (Global CCS Institute, 2019). In our paper, we will summarize the status of existing commercial and pilot projects.

There are some market forces such as investor pressure to sequester CO2. For example, ExxonMobil has committed to building a huge CO2 hub in the Houston Ship Channel (Blommaert, 2021). However, since CO2 emissions have negative externalities, markets alone are likely to fail and less than optimal CO2 will be sequestered. Therefore, many governments are considering or passing policies to encourage CCUS and cleaner energy technologies. These include policies more generally targeting carbon price such as carbon emission taxes (e.g., Norway's carbon tax at Sleipner and Snøhvit fields) and cap and trade of emission permits (e.g., E.U. carbon trading) or policies that more specifically target CCUS (e.g., U.S. 45Q tax credits) (Global CCS Institute, 2019). In our paper, we will collect information on such policies that have been proposed or passed, consider the pros and cons of the policies, and indicate the needed institutional framework for the policies to succeed.

Cost will be an important input into policy decision making and supporting economic modelling efforts of CCUS. For any market-based policies, the price of sequestration will have to cover its economic costs. We will survey the most recent literature on costs by stage, the uncertainty around these cost estimates, and the economic models of CCUS that use such cost estimates.

The structure of the paper is as follows: Part II will provide an overview of existing commercial and prototype projects. Part III will consider policies and the legal framework needed to address CO2 externalities. Part IV will summarize what we know about CCUS cost, which can then be used in economic models of CCUS and reviewed in part VI. Conclusions and suggestions for further work will be given in part VII.

Methods

We will survey the literature on projects, policies, costs, and economic modeling. Within each topic we will be focusing on economic issues, but we will categorize the topics in different ways as follow. To date, there are about 65 CCS projects in the world, 28 of them are in operation, with 37 projects either under construction or development stage (Global CCS Institute, 2020). Our highest level category will be regional with the Americas, Europe, Middle East, and Asia Pacific with country, capture type, and storage noted. In terms of CO2 capture type, four technologies are involved: pre-combustion capture, oxy-fuel combustion capture, post-combustion capture, and industrial separation. For storage, the existing applications have been enhanced oil recovery (EOR) and dedicated geology.

The existing policies or incentive programs for CCUS are in various forms. For example, tax credit, tax exemption, grants, and loans in Canada, Australia, Europe, and the U.S. In UAE, Saudi Arabia, China, and Brazil, CCUS projects are usually directly supported by state-owned enterprises (Global CCS Institute, 2020). The paper will present a summary of the incentive policies used around the globe, categorize them, and analyze whether the existing policies are detailed and clear enough to provide an accessible path for the future development and at scale deployment of CCUS. The paper will then assess the current regulations and discuss if they are up-to-date and aligned with the framework needed for CCUS to help achieve the emission target.

The paper will collect the current costs for the mature CCUS technologies - namely the amine absorption, pipeline system, EOR, and storage in saline formations - discuss the potential for cost reduction due to adaptivity and learning rates, and compare them with anticipated costs of alternative technologies. Costs associated with uncertainties and risks for both mature and developing technologies will be analyzed. The results will provide recommendations on current policies and regulations to ensure the future CCUS projects can be smoothly carried out at scale.

There is a limited number of economic models related to CCUS. In these models, the following three stages may be included: capture, transport, and storage (geological storage as well as utilization). Economic models may focus on an integrated process of CCUS. While others have modeled one or more of the three stages. Most are single objective optimization models with the goal of minimizing cost, maximizing profits, maximizing oil or gas production, or minimizing environmental impact using linear programming (LP), nonlinear programming (NLP), mixed integer linear programming (MIP), and network optimization models. A few optimize over multi-objectives (e.g., minimize total cost (including capture, transport, and sequestration, etc.) and environmental impact). Such models can be static or dynamic and with or without uncertainty. Some of the studies include generic models that are not geographically specific, others use a specific geographical region to apply their model. The geographical boundaries or level of aggregation across these latter studies range from as small as an oil field used to sequester up to countries within a region such as Europe.

Results

In looking at where we have been, we will consider what is currently considered optimal and sub-optimal in each category. The Terrell Natural Gas Processing Project, which began in 1972, is the oldest operating industrial CCUS project in the United States that has continuously captured and supplied CO2 for EOR. (Mantripragada et al., 2019). Alternatively, at least 6 coal-based CCUS demonstration projects have never seen the light of day from lack of funding or local opposition (Mulligan, n.d.). In terms of technology, a good post-combustion CO2 capture example is the Boundary Dam Projection in Canada, which successfully removes 90% of the CO2 emitted from burning coal to generate electricity.

Efficient CCUS policies need to specifically consider the different conditions across regions, industries, and the corresponding stages of CCUS. For example, while tax credits are a well-established policy mechanism in the U.S. and great incentives for mature CCUS technologies, they are not as effective for countries that are at earlier stages of development. In heavy industry (e.g., cement, iron, and steel), where the products are competitively international traded commodities, applying CCUS technologies is especially challenging, requiring more policy interventions. In contrast, for industrial processes such as ethanol production, CCUS is a lower-cost, mature, and scalable option for capturing and reducing CO2, making it more economically viable and requiring relatively less interventions (IEA, 2021).

Since models are often designed for a specific situation or question, model recommendations will more likely offer suggestions on which models best inform stake holders for given situations, along with any new modeling recommendations.

Our overall objective is to present the current state of CCUS to stakeholders (e.g., government policy makers, privately and government owned companies along the CCUS supply chain, interested non-government non-profit companies (NGOs), financial investors such as hedge funds, and society at large). So within our four CCUS related topics, we will consider weaknesses and strengths for different situations. (e.g., what works in an oil producing country may be inappropriate for countries where coal dominates electricity generation, but little oil and gas are produced). Based on this analysis and where we have been, we will suggest current best practices in projects, policies, costs, and supporting modeling. Where quantitative measures are reported, we will summarize available information, provide some measure of uncertainty, note where needed information is missing, and recommend which information is most crucial for informed decision making. Where available, we will suggest promising near term incremental changes to improve CCUS as well as suggesting more innovative long-term alternatives.

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Coal topics

Coal mining decline and opioid overdose mortality in rural central Appalachia

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Abstract

A clean energy transition will have negative impacts on communities reliant on legacy industries such as fossil fuel. This paper provides empirical evidence on how the sharp decline in coal mining during 2010-2017 increased opioid overdose mortality in coal communities in rural central Appalachia, one region featuring the coal industry and one epicenter of the U.S. opioid crisis. We first conducted semi-structured interviews with key informants in Logan County in West Virginia who stressed the "ripple effects" of the decline in coal production on coal communities. We then conducted econometric analyses, using a county level longitudinal data covering 2010-2017. We separate the channel of "deaths of despair" which emphasizes on how economic distress, unemployment, hopelessness might give rise to opioid use and misuse, from the channel of "prevalence of drugs" that highlights the accessibility of prescription and illicit opioids as one major driving force for the opioid epidemic. We find significant impacts of coal production decline, but no significant impacts of coal employment, on opioid overdose mortality. With the annual coal production dropping from 3.13 million short tons in 2010 to 1.63 million in 2017 for an average coal county in this region, our estimate implies an increase of 6.8 deaths per 100,000 population, more than two thirds of the national rate of 9.6 per 100,000 during the same period. Our results indicate that the channel of "death of despair" dominates, highlighting the importance of a just energy transition and the need for providing financial and other support to communities that might otherwise be harmed by the transition.

Methods

To examine the impacts of the coal decline on the opioid crisis in rural coal communities in central Appalachia, we first conducted interviews with key informants in Logan County, West Virginia, an area with one of the highest opioid use and overdose rates in the U.S. over the last decade. Our interviewees consisted of coal industry workers, healthcare personnel, community outreach and education organizations, treatment facilities, and local government officials. These interviews provided insights into the relationships between coal production, coal industry employment, community characteristics, and opioid use.

To conduct econometric analyses, we assembled a county-by-year longitudinal data, covering years 2010-2017, from a variety of data sources. We separated coal production from coal employment and estimated their respective impacts on opioid overdose death rates (OODR), using the former to test the channel of "deaths of despair" and the latter the channel of "prevalence of drugs". We employed multivariate regression analyses that include county fixed effects to control for time invariant factors that impact overdose deaths in a given county, in essence exploiting within-county variations in coal production and coal employment over years to estimate their effects. The analyses also include state-by-year fixed effects to control for time varying factors, including state-level policies such as PDMP (Prescription Drug Management Programs) and macroeconomic conditions, which affect OODRs in all counties within a given state in a given year. We also controlled for demographic and socioeconomic variables and health service accessibility in the regressions.

Results

The most valuable insight from our interviews is that the coal decline, in particular the decline in coal production, not only impacted coal miners and their families, but just as importantly, rippled through and damaged local communities and economies that rely on coal mining: businesses in the coal mining supply chain closed, local restaurants shuttered, local population declined due to out-migration, and the provision of public services suffered due to diminished government tax revenue.

In the empirical analyses, we find significant and negative association between coal production and OODRs, but no significant correlation between coal employment and OODRs. More specifically, during 2010-2017, a decrease of 1 million short tons in annual coal production was associated with an increase of 4.5 per 100,000 population in OODR. With the annual coal production dropping from 3.13 million short tons in 2010 to 1.63 million in 2017 for an average coal county in rural central Appalachia, the result implies an increase of 6.8 deaths per 100,000, more than two thirds of the national rate of 9.6 per 100,000 during the same period. The results are quite robust to gender and age subgroups, to deaths caused by prescription opioids (for example oxycodone or hydrocodone) or illicit opioids (such as heroine or fentanyl) , and to samples of all coal counties or coal counties where coal miners count for 1% or more of total labor force in rural central Appalachia. Furthermore, despite that the decline in coal mining during the study period was mostly due to exogenous shocks such as drop in demand for Appalachian coal, we use instrumental variables to address the concern that overdose mortality may affect coal labor supply and coal production and the results hold.

Distributed generation

Income-targeted marketing as a barrier to the transition toward equitable rooftop solar adoption

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Abstract

Low- and moderate-income (LMI) households remain less likely to adopt rooftop solar photovoltaics (PV) than higher-income households. A transient period of inequitable adoption is a common feature of most emerging technologies, but a growing community of stakeholders are calling for an accelerated transition to equitable rooftop PV adoption. To date, researchers and policymakers have focused on demand-side drivers of PV adoption inequity, but supply-side factors could also play a role. Here, we use quote data to explore whether PV installers implement income-targeted marketing strategies and the extent to which such strategies drive adoption inequity. The quote data show that installers submit significantly fewer quotes to households in low-income areas. Further, the data show that households that receive fewer quotes are less likely to adopt. As a first order approximation, the data suggest that income-targeted marketing explains about one-quarter of the difference in PV adoption rates between LMI and higher-income households. Policymakers could explore a broader suite of interventions to address both demand- and supply-side drivers of PV adoption equity.

Methods

Our data are based on a solar quote platform where installers must decide whether to submit a quote to any given customer based on a limited amount of information. Installers do not know household-level income but can roughly surmise income levels based on the home's address. We leverage the quote platform design to test for income-targeted marketing based on the number of quotes that installers choose to submit to customers in tracts at different income levels. We control for other relevant factors available to the PV installers either provided by the quote platform itself (e.g., home electricity use) or inferable from the home's location (e.g., home age). We use a Tobit model to account for the fact that the dependent variable—number of quotes received—is capped from above

Results

Rooftop PV installers on the quote platform submit significantly fewer quotes to households in low-income areas. Households in low-income areas receive around 6-8% fewer quotes than other customers, on average, when controlling for other factors. Further, the data show that customers that receive many quotes are more likely to close deals than customers that receive few quotes. As a result, income-targeted marketing reduces the probability that low-income households adopt solar, even among those households that were interested enough in solar to initially pursue a quote. We explore several hypotheses to explain income-targeted marketing. To test one of these hypotheses, we use installer headquarter locations from contractor license data to show that solar installers are disproportionately headquartered in relatively high-income areas.

Econometric modeling

Oil price uncertainty and IPOs

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Abstract

We examine the impact of oil price uncertainty on IPO volume in the oil and gas sector. By using the implied volatility of oil options, a forward looking exogenously determined uncertainty measure, we can clearly identify the effect of uncertainty on the going public decision. Oil price uncertainty have a strong negative relation to IPO volume, a one standard deviation decrease in the implied volatility results in a 25%-29% increase in the number of quarterly IPOs. The effect is concentrated among the price sensitive upstream producers. We further report that uncertainty negatively impacts the IPO withdrawal decision and increases the value to postpone the offering.

Methods

Uncertainty affects both firms' investment and financing decisions. This study focuses on how uncertainty impacts the most important financing decision in the firm's life cycle– the initial public offering (IPO). More specifically, we examine how input and output price uncertainty cause IPO volume fluctuations. To answer the research question we focus on the oil and gas sector. This setting has several advantages over studying an aggregated market wide sample. First, oil and gas firms' discount rates are directly linked to oil price uncertainty (Christoffersen and Pan, 2018), where especially upstream producers' cash flows are highly sensitive to oil price changes (Doshi et al., 2018). Second, we are able to construct a forward looking measure of uncertainty, by using the implied volatility of oil options. Being derived from options prices, implied volatility reflects the forward-looking price uncertainty assessments of the heterogeneous agents trading in futures markets (Singleton, 2014). Third, since oil firms are price takers and have little impact on the oil price, our uncertainty measure is exogenously determined

(Hamilton, 1983; 1985; Lee et al., 1995; Hamilton, 2008; Doshi et al., 2018). This allows us to clearly identify the role uncertainty plays in the IPO process.

In our main tests we explore how implied oil volatility impacts the time-series variation of IPO volume. We measure IPO volume both in terms of the number of IPOs and the total proceeds raised. Using a sample of 450 completed oil and gas IPOs during the time-period 1.1.1987-31.12.2019, we find strong support for our main hypothesis

To further identify the effect of oil price uncertainty on IPO volume, we study upstream firms in isolation. Upstream firms differ from the others in the oil and gas sector due to their sensitivity to crude oil prices (Kumar and Rabinovitch, 2013). Upstream producers engage in exploration and production, whereas downstream refiners focus on refining and marketing. Upstream producers sell their output on the physical market; thereby, their cash flows are highly sensitive to the underlying commodity price. In contrast, other firms such as refiners see different dynamics since they can take advantage of the crack spread, which is the difference between the prices of refined products and the cost of crude oil as in input (Suenaga and Smith, 2011). This built-in margin allows downstream firms to transfer part of the price variation to their customers. Therefore, the economic impact of crude oil price uncertainty on IPO activity differs between upstream and other oil and gas sector firms, upstream IPO volume should be more adversely affected by increased oil price uncertainty. Therefore, hypothesis (2) states that upstream firms' IPO volume should be more adversely affected by the level of uncertainty.

Results

A one standard deviation decrease in implied volatility corresponds to an increase of 25% (29%) in the number of IPOs (proceeds). Since, oil price uncertainty can be linked to other macro-economic factors driving IPO volume, we further study oil and gas IPO volume in relation to market wide IPO volume. This measure allows us to identify the oil and gas specific variation in IPO volume. Again, we find strong support for our main hypothesis, oil and gas sector IPOs are negatively affected by the oil price uncertainty. Next, we explore the impact of oil price uncertainty on IPO withdrawals. Our findings reveal that uncertainty increases the likelihood of withdrawals in the oil and gas sector.

Our findings lend support to hypothesis (2), upstream firms are highly sensitive while other firms IPO activity is unrelated to oil price uncertainty. Our findings are not surprising, since upstream firms cash flows are theoretically more linked to oil price changes. Therefore, their discount rates are more sensitive to the oil price uncertainty risk premium. The elevated discount rates and the lower valuations make upstream firms to refrain from conducting their IPOs during times of high uncertainty.

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Cheap Money, Geopolitics and Super-Backwardation of the WTI Forward Curve

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Amy Jaffe

Abstract

Financial speculators are more likely to trade in the most liquid short-tenor contracts. Based on this insight, we study repeating patterns of extremes in WTI forward curve slopes that cannot be explained by physical market fundamentals or basic arbitrage. We label these extremes "supernormal backwardation" (when speculators are hypothesized to buy short-tenor contracts) and "steep contango" (when they are hypothesized to sell short-tenor contracts). We estimate WTI forward curve backwardation using the slope component from the parsimonious Dynamic Nelson-Siegel factor model, and then regress the resulting time series on a variety of economic, financial and geopolitical variables. Results show that interest rates (decomposed by Adrian, Crump and Moench into predicted part and term premium) and geopolitical risk (compiled and decomposed by Caldara and Iacoviello into threats and events) explain a substantial percentage of the variation in WTI forward curve slope. Those variables

provide sufficient explanatory power that once we condition on measures of economic activity, oil storage, financial conditions, futures commitments of traders and geopolitical risk indices, the impact of hurricane events on forward curve slope becomes statistically insignificant. Most interestingly, we find evidence that speculators "buy the geopolitical threat and sell the event," resulting in greater supernormal backwardation with heightened geopolitical threat followed by decline in supernormal backwardation with the actual event. We further study the dynamic effects of interest rate and geopolitical risk on speculative activity using a Factor-Augmented Vector Autoregression analysis. Impulse response functions from the latter indicate that independent shocks to geopolitical threat or events result in heightened supernormal backwardation for a month or more. Shocks to interest rates are also found to result in sustained heightened backwardation, which may later be reversed when interest rate term premia become very negative and the WTI forward curve goes into extremely steep contango as witnessed in early 2015 and 2020 (when CL1 was briefly negative).

Methods

Following the recent literature in energy economics, e.g. Bredin et al. (2020), we use the state-space model of Diebold et al. (2006) to estimate a dynamic version of the Nelson and Siegel (1987) decomposition of the WTI forward curve term structure into level, slope and curvature factors. We show graphically that the two extreme contango events of 2015 and 2020 were preceded by periods of high supernormal backwardation, then one-year treasury term premia, as estimated using the model of Adrian, Crump and Moench (2013) became very negative, coinciding with a massive buildup in inventory that eventually led to these crises. We study the impacts of various economic, financial and geopolitical factors through a series of instrumental variable regression models (we use one-month lags of inventories as instruments for inventories) for our measure of WTI forward curve backwardation (slope) using data from March 2011 (when EIA data on US storage utilization becomes available) to end June 2021:

Model 1 includes as regressors: Kilian's Index for real economic activity (from Dallas Fed), log of U.S. storage slack (measured as one minus EIA rate of storage utilization minus 0.25), log of global crude storage (obtained from monthly issues of Petroleum Intelligence weekly), growth of industrial production and U.S. economic policy uncertainty (both obtained from FRED, St. Louis Fed), U.S. distillate supply and refinery utilization rates (both obtained from EIA), as well as data on hurricane threats and events (measured by maximum wind speeds from NOAA data).

Model 2 adds financial data on S&P500 returns and VIX (both obtained from Yahoo Finance), ACM estimates of one-year Treasury rate and its term premium (both obtained from NY Fed), and corporate credit spread (from FRED, St. Louis Fed).

Model 3 adds CFTC commitments of traders data for WTI futures, broken down by commercial/physical traders, swap dealers, and money managers.

Model 4 adds Caldara and Iacoviello indices of geopolitical threats and events.

As discussed in the abstract and results section below, commitments of traders and geopolitical risk variables add substantial explanatory power in Models 3 and 4, and interest rates become extremely significant in Model 4, indicating that a confluence of cheap money and heightened geopolitical risk is highly predictive of significant speculative buying of short-tenor WTI futures.

To study the dynamic effects of these variables, we follow Juvenal and Petrella (2015) and Bernanke et al (2005) by conducting a Factor-Augmented Vector Autoregression model that includes all of the variables above and many more, including dollar index, inflation, money supply, interest rates and term premia for one through 10 year terms, and the full breakdown of commitments of traders data into long, short and spread positions. As in Bernanke et al. (2005), we estimate five dynamic factors using Principal Components Analysis as suggested by Stock and Watson (2002), and then estimating a Vector Autoregression model for those five factors and our variables of interest, constructing confidence intervals via bootstrap as suggested by Kilian (1998). Impulse response functions confirm and expand on our earlier regression results.

Results

Our regression analysis reveals that speculators buy the geopolitical risk and sell the event, as commonly hypothesized by many but (to our knowledge) not shown empirically before this study. We also find that interest rate effects on speculative behavior in WTI become pronounced only in conjunction with geopolitical risk -- suggesting that while low interest rates for prolonged periods of time fuel bubbles in a variety of markets, their effect on oil market speculation is particularly strong when coupled with a geopolitical risk story to justify unreasonably high prices (as our previous research had suggested was the case during the Arab Spring years 2011-4). Financial and geopolitical variables together explain a very significant percentage of the variation in WTI forward curve slope, thus suggesting that regulators might wish to pay special attention to the effect of speculative activity during and around periods of low interest rates and heightened geopolitical risk.

Dynamic analysis using our Factor Augmented VAR confirm that independent shocks either to geopolitical threat or (sudden, if not preceded by threat) events result in sustained heightening of supernormal backwardation for a month or more. Likewise independent shocks to the predicted or term-premium components of one-year interest rates result in sustained heightening of supernormal backwardation -- although, as we show graphically, such events over the past decade have been sometimes followed by very negative term premia and massive build up in inventories, which ultimately result in super-contango crises as discussed earlier.

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Electricity markets

Changes in Hourly Electricity Consumption under COVID-Mandates: A Glance to Future Hourly Residential Power Consumption Pattern with Remote Work

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Abstract

The transition to remote work brings uncertainty to the future power consumption pattern. The COVID-mandates in 2020 have accelerated the transition to remote work, generating major uncertainty regarding how residential power consumptions patterns will shift. Understanding these shifts is vital for regional operators who will need to implement long term planning strategies in the event that companies continue to adopt remote work practices, or if new COVID variants prompt further extended stay-at home mandates, because the shifts will decide the optimal combination of power generation in a region. Our study examines changes in hourly residential power consumption patterns resulting from COVID-mandates in Arizona. We estimate how the COVID-mandates and the remote work practice change the hourly power consumption patterns using individual-consumer-level hourly power consumption data for 6,309 consumers and a machine learning framework. We also simulate the hourly power consumption pattern with increasing penetration of remote work under winter and summer temperature settings, and test policy effectiveness by calibrating time-of-use (TOU) rates. Our results show that COVID-mandates increase the power consumption in the afternoon by 13%, and change the power consumption pattern in winter from two-peaked shape to one-peaked shape. Furthermore, we show that the residents' income, race, and house size are significantly correlated with the changes in power consumption, and the correlation is not linear. We find that, by changing TOU rate for 10% of utility rates based on power consumption changes, the peaked demand could be reduced by 10%. Our

results show: (1) the need for modifying previous energy generation combination planning by changing the peak demand hours and adjusted by demographic factors; (2) equity concerns regarding TOU pricing and inability to shift electricity consumption among different consumer groups under the new remote work era; (3) during the transition, governments could lower the maximum load of power consumption by modifying the TOU rates.

Methods

We use random forest model to forecast the counterfactual power consumption pattern under four scenarios: (1) counterfactual power consumption without COVID-mandates from March 16 to April 15; (2) counterfactual power consumption with COVID-mandates, under summer weather setting and without a modified electricity rate; (3) counterfactual power consumption with COVID-mandates, under winter weather setting and without a modified electricity rate; (4) counterfactual power consumption and modified rates with COVID-mandates from March 16 to April 15.

On the other hand, the modified electricity rates in scenario (4) are also based on the results of scenario (1). Based on the results of scenario (1), we increase the electricity rates by 10% whenever COVID-mandates increases power consumption, and decrease the electricity rates by 10% whenever the mandates decrease power consumption. Our simulation results support for demand side management by adjusting the TOU rates. There is the possibility that the utility company would aim to smooth out changes in the demand curves by adjusting pricing mechanisms. We simulate potential power consumption responses if the TOU electricity rates are adjusted by a utility provider to incentivize power consumption shifts. This illuminates how low-income or vulnerable populations can be impacted by prices shifts when they are working from home.

The main dataset for our analysis is an hourly power consumption data set for individual power consumers in Arizona, provided by the utility company Salt River Project (SRP). After removing individuals with less than 10 observations, this dataset contains 6,549 individuals' hourly power consumptions from 2019-03-18 to 2020-04-30, with 225,487 observations across those individual households. The demographic and technology information, such as income, race, and information regarding number and type household electronic devices, is compiled from the SRP 2017 Residential Equipment and Technology Survey. The local temperature and relative humidity data are collected from National Oceanic and Atmospheric Administration.

Results

Our results showed that the COVID-mandates varied hourly power consumption patterns in all hours and seasons. During the COVID-mandates, the hourly power consumption increases during the afternoon and decreases during the morning. In general, the pandemic lowers the average power consumption between 0 – 13 % from 1 to 10 am, while increasing average power consumption between 2 – 14 % from 10 am to 12 pm. We found that the maximum increase of 13% (0.17 kWh) occurred at 15:00. On the other hand, the power consumption at 7:00 decreases by 14% (0.14 kWh). The impact of COVID-mandates to the power consumption pattern differs under weather setting. In summer, the power consumption increases during the afternoon but less during the morning. However, the changes in winter are more significant, that the power consumption pattern is changed from two-peaked to one-peaked shape. The power consumption during the afternoon is significantly higher (14%) than before the pandemic.

On the other hand, the stratifying analysis for the changes in power consumption shows more details of how different demographic groups respond to remote work. We find that the income, race, and household size are correlated with the likelihood to be classified into different groups. The low-income groups within American Indian/Alaska Natives consumes less power in the morning (minimum -0.43 kWh at 7 am) and Native Hawaiian consume less power in all hours (minimum -0.43 kWh at 7 am). On the other hand, the changes for African and Asian low-income groups are less significant. Job data from U.S. Bureau of Labor Statistics shows that, African Americans are less likely to work from home, and therefore could result the changes in power consumption to low-income African Americans more similar to African Americans above poverty line. Nevertheless, the different changes in power consumption between races and income shows that the transition to remote work could only occur to high-income groups, and thus design infrastructure and reform utility rates according to the remote work lifestyle could benefit the high-income groups while charges low-income household more.

Geographic Price Differences and the Allocation of Wind Power: Evidence from a Swedish Electricity Market Splitting Reform

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Abstract

This paper provides empirical evidence of the investment effects in wind power following the 2011 Swedish electricity market splitting reform, exploiting a unique data set of all Swedish applications for wind power since 2003. These data provide information on the submission date of each application, the owner of the plant, and whether it was rejected or approved. Using a difference-in-differences (DiD) estimator, I find that large firms increased their applications by 15 percent in the high- relative to the low price region following the announcement of the reform. This result holds both for rejected and approved applications, demonstrating that the effect is driven by investor preferences and not differences in the probability of approval. Further, I find that small, often locally owned firms did not react to the reform. A likely reason for the absence of an effect for small firms is that their locational choice usually only includes one of the regions, highlighting the importance of accounting for investor diversity when evaluating future market splitting reforms throughout Europe.

Methods

Electricity wholesale markets are typically organized as auctions. Producers, retailers, and large industrial consumers submit bids to a power exchange that aggregates the bids to obtain market clearing prices and quantities. Since production and consumption take place at different locations, trade is enabled by transmission lines, with limited capacities. In European electricity markets, the auction design only takes into account a subset of these constraints, ensuring that prices are uniform at least within certain predefined areas, or zones. This pricing model is called zonal pricing. When there is intra-zonal congestion, the transmission system operator (TSO) activates succeeding mechanisms to redispatch production and consumption until the real physical transmission constraints within that zone are met. This mechanism is usually also auction based, although the exact procedures differ between countries.

During the last decade, Europe's electricity markets have in become increasingly integrated, in the sense that the market clearing mechanisms now allow for market based trade across the continent. However, this development has not been matched by corresponding investments in transmission capacity neither within nor across borders. This has lead to increasing issues related to transmission congestion, exacerbated by significant investments in intermittent generation. As a result, European regulators are now discussing the potential advantages of partitioning countries into several price zones, or even to introduce locational pricing.

Zones are usually defined according to national borders, independent on where the real transmission bottlenecks exist. One of few exceptions is Sweden, that in 2011 was split from one to two zones (formally, it was four zones, but only one of the transmission constraints was binding). In this study, I evaluate the investment effects of the Swedish market splitting reform using unique data on all Swedish wind power applications since 2003. These data contain information about the application submission date of each turbine, whether it was approved and subsequently built, as well as a large set of plant characteristics. The importance of examining application data is emphasized by the fact that lead times are usually several years. Therefore, the effect of the reform on investor behavior can only be detected with any degree of precision when also evaluating application data. By including also applications that were rejected, I can separate the effect on investor preferences from the effect on actual wind power constructions. Since a non-trivial share of the applications are rejected due to local opposition, such frictions are non-negligible.

Results

I find that large firms increased their applications by 15 percent in the high- relative to the low price region following the announcement of the reform. This result holds both for rejected and approved applications, demonstrating that the effect is driven by investor preferences and not differences in the probability of approval. Further, I find that small, often locally owned firms did not react to the reform. A likely reason for the absence of an effect for small firms is that their locational choice usually only includes one of the regions, highlighting the importance of accounting for investor diversity when evaluating future market splitting reforms throughout Europe.

Innovation Trends in Electricity Storage: What Drives Global Innovation?

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Abstract

Economic research has recognized the importance of transitioning to a higher use of clean technologies in energy production to curb greenhouse gas emissions (e.g. Acemoglu, 2002). In that effort, innovation is key to develop new technologies and to speed up the decarbonization of the energy sector (e.g.

Johnstone et al., 2010; Lanzi et al., 2011). In particular, the electricity sector has received a lot of attention as it is the single largest emitter of carbon. In this sector, a major technological challenge to transition towards more renewables is the availability of large-scale and cost-effective electricity storage. Electricity storage can help reduce the intermittence problem of renewable technologies like wind and solar in addition to improving the efficiency of conventional power plants by reducing ramping costs (Lazkano et al., 2017). While the benefits of electricity storage are clear, the status of innovation, its drivers and links to environmental policy are less known. Our goal is to improve the understanding of what drives innovation in electricity storage at the global level. Specifically, we ask following questions: Which are the most innovative technologies in electricity storage? How does innovation in electricity storage develop over time and among countries? What drives innovation in electricity storage?

A large share of literature on innovation in the energy sector has empirically examined the drivers of energy-efficient and renewable innovation. For example, using U.S. energy patent data from 1950 to 1994, Popp (2002) finds a strong and positive impact of energy prices on new patents. He also finds that the amount of existing patent applications shapes the direction of innovation. Another key study is Acemoglu et al. (2012) as they set up the framework to study induced innovation in the energy sector by incorporating market sizes along with energy prices. In addition, they theoretically established that environmental policy is a strong determinant of innovation, where carbon taxes and research subsidies encourage energy-efficient innovation. While many have focused on the invention of clean technologies and energy-efficient conventional technologies in energy generation and transmission, energy storage has received far less attention. Hall and Bain (2008) refers to energy storage as “the key to unlocking the door of renewable energy.” Fabrizio et al. (2017) examines the impact of demand- and supply- pushed policies on energy storage innovation using international panel data. For a given country, they find only demand-pull policies promote domestic innovation in energy storage. Building on the framework of Acemoglu et al. (2012) and using a firm-level dataset of patents, Lazkano et al. (2017) is one of the first to empirically analyze the importance of electricity storage in the energy sector. While their focus is on the role of electricity storage in fostering innovation in both conventional and renewable electricity generation, our focus is on studying innovation trends in storage and their determinants.

Methods

To answer our research questions, we analyze innovation trends in electricity storage using a firm-level global patent dataset from 1978 to 2019. Then we estimate the determinants of innovation in electricity storage by estimating a log-log model following Popp (2002) on energy prices, a knowledge stock, R&D investment, and the other variables.

Our global dataset includes energy storage and electricity generation patents, which are drawn from the Organisation for Economic Cooperation and Development (OECD). Our dataset is unique because we identify technologies related to electricity storage by creating a new list of storage International Patent Classification (IPC) codes. Overall, our dataset includes 219,265 patent applications across 1,881 regions in 93 countries from 1978 to 2019. Out of these, there are 31,446 electricity storage patents. We also consider energy prices and macroeconomic variables such as government R&D, electricity consumption, and GDP.

Results

Our analysis shows an overall positive trend in storage patents from 1978 to 2019, indicating its importance in the electricity sector. Most innovation is directed at improving batteries which have been the main electrical energy storage vessel used in the last decades. Not surprisingly, Japan, the U.S. and Germany lead innovations in the electricity sector.

Our empirical results highlight the importance of electricity prices and past innovation to determine innovation in storage. First, a one-unit increase in electricity prices leads to a reduction around 16% in the share of storage patents relative to electricity generation patents. This is in contrast to prior literature that finds a strong and positive impact of energy prices on other clean energy patents (e.g. Popp, 2002). A reason could be that, unlike innovation dynamic in electricity generation, electricity storage benefits both renewable and conventional electricity generation. In line with others, we do find a positive and significant price effect when we use an energy price index as the instrument. Second, we emphasize the importance of past innovation and the rates of decay and diffusion. In line with Popp (2002), who finds that the quality of existing knowledge has a strong and significant positive effect on innovation, we find that one more citation-adjusted past patent leads to almost 10.6% more innovation in the ratio of storage to electricity patents after controlling for past innovation in generation technologies. The reason is the strong relationship between storage and both renewable and fossil-fuel technologies in generation.

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Do Electricity Consumers Respond to Prices or Peers? Evidence from a Novel Electricity Billing Tournament

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Abstract

We examine an energy conservation program that instills both pecuniary and nonpecuniary incentives using a tournament among peer military households. Under the tournament, households only pay for electricity that exceeds 110 percent of a peer-group average and receive a rebate for each kilowatt hour below 90 percent of the peer-group average. Prior to the program, no household paid for electricity. We evaluate impacts of the program two ways. First, we use difference-in-differences to estimate how introduction of the program affected electricity use for those near the peer-group average (and paid/received nothing throughout) in comparison to those who received payments or rebates. Second, we examine how arguably exogenous changes in the peer-group average, driven by entry and exit of households, affected subsequent electricity use by continuing households. We find that the program causes greater conservation by high-use households that are required to make payments under the program, but that low-use households respond against their pecuniary interest and consume more. Put another way, both groups bunch toward the peer-group mean. Over time, for continuing households that switch between rebate and payment percentiles, electricity use responds the same to both decreases and increases in the peer-group mean. These households tend to reduce electricity use if they were at the above-average percentiles and, in contrast, increase use if they were at the below-average percentiles regardless of the increases or decreases in the effective price. We discuss ways that monetary incentives and competitive psychology may be mixing to give rise to these observed impacts.

Methods

This paper contributes to the literature on electricity demand response by studying an energy conservation program that has provided unusual pecuniary and non-pecuniary incentives. The setting involves military households living on bases in Hawai'i. Before the program, military households did not pay for electricity - it is included as a part of the housing allowance for enlisted persons and their families. Given a high and rapidly growing cost of electricity, the military was motivated to develop a revenue-neutral tournament that would encourage conservation. Under the tournament, households only pay for electricity use that exceeds 110 percent of a peer-group average, while households that consume below the 90th percentile of the peer-group average earn a per-kilowatt-hour rebate for conservation below this threshold. Households that consume between 90 and 110 percent of the peer group's mean consumption pay nothing. For six months before the program, households received monthly information about their consumption, their peer group mean, and the payment or rebate they would have been subject to if the program had already commenced.

Data on military electricity billing records were assembled by a company that operates the majority of military housing communities in Hawaii. The data provide household-level monthly electricity use for more than 27,000 military households on Oahu island, Hawaii from 10/2009 through 9/2018. The billing data includes household monthly electricity use, the amount of payment or rebate, assigned peer group, neighborhood, zip code, and housing characteristics. Since weather variation affects electricity demand, some specifications include major weather elements. We use weather data from NOAA Global Historical Climatology Network (GHCN). We match the weather station coordinates to each zip code using spatial mapping to obtain weather data at the zip code level.

Peer-group comparisons in this military tournament echo the use of social comparisons to "nudge" people toward lower energy consumption. Payments and rewards for deviating from the group mean add salience and economic bite to these comparisons. Thus, both psychological and economic factors are likely germane to the program's impacts, and we use a couple of strategies to disentangle these effects to the extent possible. The first identification is difference-in-difference in which the control group are no-payment households that consume near the average level and two treatment groups are (1) payment households who consume far above the peer group average level and (2) rebate households who consume much less than the peer group average level. A potential weakness of the difference-in-difference estimates is that the control - no-payment households that consume near the average - may nevertheless be influenced by the program. Thus, to complement difference-in-difference findings we consider longer-run changes over time as households enter and exit each peer group. When a high-use household moves out (e.g., their tour of duty ends) or a low-use household enters, the peer-group mean declines; conversely, when a low-use household exits or high-use household enters, the peer-group mean rises. For continuing households, these changes of peer group members are exogenous changes that affect the likelihood and size of payments and rebates in the tournament.

Results

First, using a difference-in-difference estimator, we find that under the monetary incentives, in comparison to non-payment households, while households in the payment group reduce consumption by about 16%, households in the rebate group surprisingly increase consumption by about 8.4%. The positive effect in the rebate group may seem surprising as it goes against pure economic incentives: the marginal price increased, so it would imply an upward sloping demand curve for a rational household. It could be that households were responding to the decreases in average price. Alternatively, there may be another social or psychological factors at play, as these households gravitate toward to peer-group average. The response from the payment group, however, is almost double the magnitude as the rebate group and accords with pure monetary incentives. Note, however, that while average price is positive, in contrast to the negative average price for the rebate group, the magnitude of average price is much smaller than it is for the rebate group. This suggests that household do not simply respond uniformly to average price. With a similar proportion of households within payment and rebate groups, the aggregate effect of the program is to reduce electricity use.

Second, employing the exogenous changes in peer-group average use, we find that if the peer-group average decreases and making the tournament more competitive (effectively a price increase), continuing households at all consumption percentiles reduce daily use. But the effect size differs across consumption percentiles and whether the peer-group average exogenously increases or decreases. When the peer-group average decreases, which is the usual case, we find that high-percentile users making payments decrease use somewhat more than average users do, while low-percentile users receiving rebates increase use much more than average. This result mirrors the bunching-toward the peer-group-mean observed in the difference-in-difference estimates. Interestingly, household response to the reverse changes - when the peer-group mean increases - is the same. That is, households at low-percentile increase use while households at high percentiles decrease use. The further households were away from the group average use, the larger adjustment they make toward the group average level. These results indicate that the interaction between monetary incentives and behavioral factors makes the peer comparison more powerful that we have not seen documented in the prior literature.

Covid-19 and the Information Content of Electricity Futures

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Abstract

This study investigates the effect of the COVID-19 pandemic on the predictive content of electricity futures for delivery at PJM Western Hub during peak and off-peak periods. In particular, we examine the extent to which electric power futures prices shifted in anticipation of lower future spot prices associated with pandemic-induced reductions in economic activity as more information regarding the pandemic became known. We capture the relationship between prices of future contracts and the expected spot prices by relying on the Fama & French (1987) framework. Building on this framework, we further recover the futures-spot price relationship by constructing an alternative model which relaxes the assumption of a constant risk premium. We use a linear lasso shrinkage estimator to utilize a large set of time-varying risk premia predictors. Our estimates suggest that based on information embedded in electric power futures prices at the end of 2019, traders overpredicted the actual spot prices realized during the first half of 2020. We find evidence that traders shifted their expectations regarding future spot prices as more information about the pandemic entered the market. The spread between spot price expectations based on information at the beginning of April 2020 and realized spot prices in the subsequent months is much narrower. We find that differences between spot price expectations and actual spot prices are larger for peak contracts than for off-peak contracts. This paper has implications for the effect of the COVID-19 pandemic on electricity markets and for measuring expected spot prices based on futures' information in the presence of time-varying premia.

Methods

The prices of electricity future contracts reflect traders' expectations of the spot price of electric power on the date of the contract's maturity plus a premium to compensate parties to the exchange for the risk they bear in the contract. Previous research on the predictive content of commodity futures prices has largely followed the framework developed by Fama and French (1987), which we also adopt. We modify their model to allow for the existence of time-varying premia. We use a linear lasso shrinkage estimation method in order to efficiently utilize the information in the large number of correlated potential predictors of time-varying premia in the electric power market. We estimate both models (with constant and time-varying premia) using training data from periods prior to the pandemic. Based on the estimated coefficients and the price of futures contracts at a specified point in time, we then calculate traders' expectations of spot price during the subsequent two-year period. We calculate traders' expectations of future spot prices based on the prices of futures contracts trading at dates before the pandemic emerged and also at dates during the period when information emerged about the pandemic, its likely economic consequences, and government policy responses. We compare these forecasts to the realized spot prices in the market and infer how traders update their expectations of future spot prices based on emerging information about the pandemic.

Deviations between traders' expectations of future spot prices at the time futures contracts trade and the eventual realized spot prices may be due to any information or factors that affects the realized spot price but is not observable by traders when the futures contract is traded. The most important such factor is weather; unusual, and unanticipated, weather conditions at the time of realized spot prices have a substantial impact on spot prices that cannot be reflected in futures contracts prices. In order to isolate the effect of the evolution of information on COVID-19 on futures prices, we estimate an econometric model of the deviation of realized and expected spot prices on weather and other factors unobservable at the time futures contracts trade.

Our futures price data are for off-peak and peak electricity contracts traded on NYMEX. Spot prices are collected from PJM. Data on potential determinants of time-varying premia include average daily temperatures recorded at two stations in Pennsylvania (NOAA), gas futures prices for delivery at Henry Hub (NYMEX), gas spot prices (Henry Hub), 1-month, 3-month, 6-month, 1-year Treasury Bill rates (FRED), VIX volatility index (FRED), SP500 prices (WSJ), average monthly load (PJM), measures of US policy-related economic uncertainty (policyuncertainty.com). In line with previous literature, we calculate the skewness and variance of electric power spot prices and include them in the lasso regressions.

Results

We find evidence that spot price expectation of traders in the PJM electricity futures markets changed substantially as information emerged about COVID-19. As information about the pandemic emerged, traders first lowered their spot price expectations, but then partially reversed that as more information emerged regarding policy responses and their effect on demand for electric power.

Predictions derived from the Fama & French (1987) model with constant premia and the modified model with time-varying premia are surprisingly similar, suggesting a relatively small role of time-varying premia in futures pricing. These models' predictions suggest that based on information embedded in futures prices in January 2019 traders likely over-predicted the realized spot prices during the following winter and the subsequent months. The likely reasons for that are anticipation of a colder winter in 2019-2020 than it occurred and distortion of the demand and supply of electricity due to the pandemic. Predictions based on information available to traders in December 2019 also shows over-prediction of what the spot prices would be in the first half of 2020 but to a lesser extent than predictions in January 2019. Traders likely adjusted their 2019-2020 weather expectations in December 2019, but at that time they could not anticipate the pandemic shock. Predictions of future spot prices based on futures contracts traded in April 2020 reflect how traders' expectations of future spot prices adjusted in response to the onset of the pandemic and news regarding its likely impact on economic activity. Those predictions are substantially lower than predictions of spot prices for the same time period but based on futures prices from contracts trading in January 2019 or earlier dates. Our ongoing work is examining the drivers of the prediction errors during this timeframe, and will isolate the effect of COVID-19 from other sources of spot price forecast errors, especially weather surprises.

How to design reserve markets? The case of the demand function in capacity markets

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Abstract

This paper studies reservation markets' design in the context of the provision of essential goods with time-varying and uncertain stochastic demand; They are typically under-procured by private agents, which leads to under-investment to meet peak demand compared to the socially optimal. In these industries, a regulator determines the capacity required to met peak demand and organizes the procurement of the capacity deemed necessary through a reservation market. The paper contributes to the literature by developing a novel approach to study the design of the demand function in the reservation market and the interdependencies with the subsequent production and retail markets for the essential. We provide a complete framework using a sequential analytical model of the three markets and demonstrate how the reservation market demand curve specification affects the demand and the equilibria in the production and retail markets. We describe different market design regimes, the process through which those markets are impacted, and their outcome in terms of investment level, prices, and welfare. The model results and the associated policy implications are discussed first using a general framework and then with reference to electricity markets where capacity reservation is often used to ensure adequate investment to ensure the security of supplies.

Methods

This paper discusses the economic impacts various designs for reservation markets can have and their policy implications. We stress that the centralized design, where the capacity is centrally bought by a single entity, is essentially a question of cost passthrough between the entity and the retailers or the consumers. On the other hand, in the decentralized design, each retailer estimates its client portfolio's consumption, derives from this an individual demand function in the reservation market, and passes the cost onto its clients. Therefore, a key question under the decentralized design is the assessment of the marginal value of a capacity for retailers and which drivers can impact it. To our knowledge, there has been no comparison between these reservation market design options, the incentive properties of these alternative approaches, and their ability to restore the socially optimal level of investment.

In this paper, we develop a model that sheds light on the interactions between the reservation market design and the incentives of producers and retailers. The model provides some new and non-intuitive insights, which suggest that such reservation markets should be carefully designed. When defining the reservation market's demand function, regulators indeed need to be careful about indirect effects. We demonstrate that the different design options have distinct economic effects on the demand, which in turn affects the main market outcomes in terms of prices and quantities and comes with significant redistribution effects for consumers, producers, and retailers. More generally, our model allows us to analyze the endogeneity between the optimal market outcome that regulators aim to restore through their intervention and the design of the reservation market implemented. A type of reservation market design (e.g., the centralized approach) can be seen as optimal given a set of inefficiencies. However, the other market design (e.g., the decentralized approach) may create more welfare than the initially envisaged optimal solution by reducing the inefficiencies.

The paper's main contribution lies in the analytical framework representing the different market design options for the demand specification in reservation markets, which allows drawing new insights on the incentive properties of the alternative design approaches and their ability to restore the socially optimal level of investment. We describe the rules associated with the centralized and decentralized model, enabling us to model the effect of each regime on the retailer's strategies and final consumer's demand and study the regulatory parameters used to implement the reservation market's demand function. We untangle the interdependencies between the three markets (reservation, wholesale, and retail) and their impact on investment decisions. More specifically, our model shows how the design of the reservation market impacts producers' and retailers' profits in subsequent wholesale and retail markets. We analyze how each reservation market design and its corresponding rules affect retailers' demand on the wholesale market.

Results

We start our analysis using the canonical benchmark model for non-storable goods characterized by time-varying demand, which describes the relationship between the short-term production decisions and the long-term investment decisions. Producers make long-run investments in a single technology in the upstream market in order to be able to subsequently produce a homogeneous good, given an uncertain future demand. Then, the downstream retailers aggregate and resell the goods at no cost to the final consumers. We introduce a price cap which can be interpreted as representing the effect of different types of market distortions induced by a range of market failures and regulatory interventions, which are typical for such essential goods and can take the form of price caps or regulations with a similar effect on price dynamics in practice. Such a price cap reduces expected revenues of producers (particularly during peak periods) and undermines investment compared to the level that would be needed to reach the socially optimal level of installed capacity. Moreover, when the price cap is reached, the investment availability becomes a public good as the demand becomes inelastic. Due to the impossibility of efficiently rationing consumers, they incur a significant welfare loss.

We start with the case of a centralized reservation market, we build on the previous literature and start with the canonical design found in Leautier (2016) and Holmberg and Ritz (2020). In this model, the key assumption is that the reservation market does not affect the demand. It is similar to assume that the capacity price is passed onto the consumers via a lump-sum tax from a practical view. Such market design allows restoring the socially optimal level of investment, given the inefficiencies in the system.

We then investigate the case in which the reservation price impacts the consumers at the margin. In this case, the centralized design is similar to a Pigouvian unitary tax. We show that the indirect effect of the reservation market is ambiguous for social welfare by bringing more or less welfare than the first-best of the canonical design.

As a third step, we extend our analysis to the implementation of a centralized regime in which the regulator chooses to allocate the cost based on actual retailers' market shares. This allocation creates an intermediary outcome between the unitary tax and the lump-sum tax while having significant redistributional properties.

Finally, we analyze the case of a decentralized reservation market and focus on the ways in which individual strategies can form an aggregated demand function in the reservation market when retailers are obliged to cover their quantity sold on the retail market given a penalty system. To do so, we analyze the optimal capacity bought by retailers in the reservation market. We find that such a decentralized approach for the demand function can approach the optimal level of investment under specific conditions. Indeed, the marginal value a capacity brings retailer profit depends on the market structure in the retail market, the consumers' demand function, and the penalty system.

Commercial Consumers Pay Attention to Marginal Prices or Average Prices? Evidence from Nonlinear Electricity Pricing

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Abstract

It is generally assumed that firms and consumers will optimize their consumption behavior based on marginal prices in policy discussions of taxation, nonlinear pricing, and subsidies. Thus, scholars often take this assumption for granted when discussing consumers' reactions to nonlinear pricing structures. Research on electricity demand provides mixed results on whether consumers respond to marginal price changes. The existing discussion focuses more on residential consumers. Reiss and White (2005) find that residential consumers respond to marginal electricity price. On the contrary, some studies show that residents respond more to average electricity prices than to marginal prices (Ito, 2014; Shin, 1985; Borenstein, 2009). Carter and Milon (2005) explain that residential consumers are less directly responsive to marginal prices due to cognitive difficulties. The average price is often used instead of marginal prices by consumers in part because marginal prices are difficult to monitor and calculate (Liebman and Zeckhauser, 2004; De Bartolome, 1995).

Almost 18% of U.S. national energy consumption is attributed to commercial buildings (Commercial Building Energy Consumption Survey (CBECS), 2015). In light of the high demand for energy, commercial customers are expected to be more price sensitive. If evidence indicates that consumers are more responsive to average prices, policies that rely on marginal pricing to motivate conservation will be less effective than policies aimed at average prices. Yet, there is no such evidence in the literature related to electricity consumption. To the best of our knowledge, we provide the first empirical evidence looking at whether commercial consumers respond to average or marginal electricity prices under nonlinear pricing. Our findings provide implications for conservation policies that target commercial consumers.

According to our empirical analysis, commercial consumers respond to both marginal and average prices, but respond differently depending on how much electricity they consume. Higher-usage consumers tend to respond more to average prices, whereas lower-usage consumers are more sensitive to marginal prices. First, we examine whether electricity consumption shows discontinuities at the kink points in the nonlinear price schedule. Such discontinuity will be observed if consumers perceive marginal prices. The consumption distribution plots by season and by industry reveal obvious discontinuities at cutoff points. We also conduct a falsification test to determine whether consumption changes at random cutoffs elsewhere. Results shows continuous consumption at random cutoffs, confirming the responsiveness of commercial consumers to marginal prices. Second, we run two-stage least squares (2SLS) models with policy-induced instrumental variables to estimate the effects of marginal and average prices on commercial electricity consumption at each cutoff. Instrumental variables are used to eliminate heterogeneity issues. Moreover, the midway consumption polynomial is included to address the mean reversion problem. Both marginal and average prices appear to affect consumption significantly. Marginal price effects are greater at the first two cut-off points, while average price effects are greater at the last. We conclude by offering a few suggestions for policymakers regarding energy conservation.

Methods

Data

Our study examines a decreasing block pricing structure for commercial consumers in Phoenix metropolitan, Arizona. In this price plan, the marginal price drops when a consumer's cumulative consumption within a given month reaches 350 kWh, 530 kWh, and 685 kWh. The smart meter data enables us to construct individual-consumer-level daily panel data for 397 commercial accounts, 473,570 observations, in the study area from 05/01/2013 to 12/31/2016. Having a larger sample size results in more reliable and generalizable results.

Empirical Strategy

Instrumental variables

Our goal is to quantify the causal effects of marginal and average electricity prices changes on commercial electricity consumption. A critical problem with tiered pricing is that the marginal or average price is determined by the cumulative consumption of each month. Thus, price variables correlate with daily consumption, cumulative consumption, and error terms, causing endogeneity issues. This can be solved using instrumental variables, measuring the policy-induced changes in marginal price and average price.

$\Delta \ln MP_{id} = \ln MP_d(\text{monthly consumption}_{id}) - \ln MP_{dm}(\text{monthly consumption}_{idm})$

$\Delta \ln AP_{id} = \ln AP_d(\text{monthly consumption}_{id}) - \ln AP_{dm}(\text{monthly consumption}_{idm})$

Two-Stage Least Squares (2SLS) regressions

We use the first differences to control for the confounding consumer-level factors such as building characteristics, business operations, building occupancy, and firm revenue. A 2SLS model can be employed to calculate IV estimates. When marginal and average price variables are both included in one equation, the results show abnormally positive effects of average price variation on electricity consumption in aggregate regression and regressions for 350-kWh and 530-kWh thresholds. In other words, daily electricity consumption grows when the average price rises. Possible explanations for the counterintuitive results include the strong collinearity (with a correlation coefficient of 0.87) between the changes in marginal prices, β, and average price, α. As a result, our primary model analyzes them separately.

$\Delta \ln(\text{daily consumption}_{id}) = \beta \ln(\text{MP\_predicted}_{id}) + f(\text{midway daily consumption}_{idm}) + \Upsilon X_{id} + \mu_{id}$

$\ln(\text{MP\_predicted}_{id}) = \Pi \Delta \ln MP_{id} + f(\text{midway daily consumption}_{idm}) + \Phi X_{id} + \omega_{id}$

$\Delta \ln(\text{daily consumption}_{id}) = \alpha \ln(\text{AP\_predicted}_{id}) + f(\text{midway daily consumption}_{idm}) + \delta X_{id} + \eta_{id}$

$\ln(\text{AP\_predicted}_{id}) = \Pi \Delta \ln AP_{id} + f(\text{midway daily consumption}_{idm}) + \Phi X_{id} + \omega_{id}$

Since we use daily panel data, the polynomial of midway consumption at the daily level *midway daily* $\textit{consumption}_{idm}$ is also included to control for unobservable factors that can cause consumption changes.

Robustness check

For each threshold, we set two kinds of windows: a window of 3 days before and 3 days after, and another window of 4 days before and 4 days after. We use daily consumption in the two windows when consumers crossed each cutoff to run the same 2SLS model.

Falsification test

We select cutoff points other than the three to test for discontinuity in daily electricity consumption elsewhere. The chosen thresholds are 200 kWh, 400 kWh, 600 kWh, and 800 kWh. Additionally, the bandwidth for constructing density estimators on either side of the cutoff is 50. Continuity (or absence of discontinuity) in consumption in the randomly selected cutoff points supports our conclusion that discontinuity only occurs at 350-kWh, 530-kWh, and 685-kWh due to the changes in the marginal price.

Results

Descriptive evidence about the commercial response to marginal prices
We first provide visual evidence to highlight the daily electricity consumption discontinuities at the

cutoff points. **The consumption distribution plots by season and by industry reveal obvious discontinuities at cutoff points.**

Overall impacts of the marginal and average price

Based on the results of 2SLS regressions using aggregate data, the price elasticity with respect to marginal price is -0.639. If marginal price declines by 1%, daily consumption will increase by 0.639%. The price elasticity with respect to average price is -0.592. If the average price decreased by 1%, daily consumption will rise by 0.592% . From an aggregate perspective, the price elasticity with respect to marginal price is larger than that with respect to average price, suggesting the possibility that commercial consumers respond to marginal price more than average price.

Based on the results of 2SLS regressions using consumption data close to the three thresholds, the price elasticity of marginal prices is -0.950 and -0.958. A 1% drop in the marginal price causes the consumption around 350 kWh to increase by 0.950%, and consumption around 530 kWh to increase by 0.958%. the price elasticity of average prices is -0.581 and -0.621. A 1% decrease in average price results in a 0.581% increase in electricity consumption near the 350-kWh cutoff, and a 0.621% increase in consumption near the 530-kWh cutoff. It suggests that the marginal price change exerts a greater influence on electricity consumption around the 350-kWh and 530-kWh cutoffs than the average price change does. But based on results near the 685-kWh cutoff, marginal price elasticity is -0.494 and average price elasticity is -0.709. A 1% decline in marginal and average prices is associated with 0.494% and 0.709% increases in consumption at the 685-kWh cutoff, resepectively. It indicates that when it is close to the third cutoff, marginal price changes have a much smaller impact than the average price. As the block pricing gets lower, average prices begin to dominate. Conversely, marginal price variation is less impactful when it is near tire four. The results around the 685-kWh cutoff suggest that large consumers are less sensitive to marginal prices. The reason could be because large electricity consumers know that their monthly electricity usage will exceed the third cutoff and will be charged at tier four's lowest unit price. They respond only to average prices without much thought for marginal prices.

Existing studies have estimated the price elasticities for residential and commercial consumers. In the residential sector, the short-term price elasticity is -0.2 and the long-term price elasticity is -0.7 according to Bohi and Zimmerman (1984)'s survey data in the United States. Filippini (1999) estimates the residential price elasticity in 40 Swiss cities to be -0.30. Californian households have an annual electricity price elasticity of -0.39, as determined by Reiss and White (2005). The National Institute of Economic and Industry Research (2007) finds the long-run price elasticity of electricity for residential and commercial consumers in the Australian National Electricity Market is -0.25, and -0.35, respectively. As a result, the numbers that come up most often are -0.2 to -0.4 for short-run elasticity, and -0.5 to -0.7 for long-run elasticity. According to our research, the marginal price elasticity on aggregate is -0.64, whereas the average price elasticity on aggregate is -0.59. Our short-run price elasticities are higher than those in the existing literature, potentially because we are examining higher-frequency consumption changes and we are focused on commercial consumers.

Robustness check

Using the 3-day window at each threshold and for aggregate data, 2SLS models show that a 1% increase in marginal price is associated with a 0.85%, 0.96%, and 0.51% decrease in electricity consumption. With average price rises by 1%, electricity consumption will decrease by 0.52%, 0.62%, and 0.76%, respectively. Using the 4-day window at each threshold and for aggregate data, 2SLS models suggest thata 1% increase in marginal price corresponds to a 0.85%, 0.96%, and 0.52% decrease in electricity consumption. As average prices rise by 1%, electricity consumption will decline by 0.51%, 0.61%, and 0.74%, respectively. As a result, the robustness checks support our main findings and indicate that larger electricity consumers who consume closer to or more than 685 kWh per month are less sensitive to marginal price than smaller commercial consumers.

Falsification test

Aggregate data shows a continuous daily consumption pattern at 200-kWh, 600-kWh, and 800-kWh cutoffs, but only a small discontinuity at 400-kWh. These randomly selected cutoff points do not have changes in marginal prices. Compared to the sharp discontinuity at 350-kWh, 530-kWh, and 685-kWh thresholds, the results of the falsification test indicate that these other cutoffs do impact consumption and that commercial consumers are indeed responsive to marginal prices.

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Privatization vs. unbundling: Assessing the environmental impacts of China's electric industry restructuring

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Abstract

Privatization and unbundling are the two pending electric industry restructuring reforms in many developing countries, while few studies have explored the relative environmental effects and connection of the two reforms. In this paper, we empirically examine the effect of privatization and unbundling on power plants' air pollution intensity. We exploit both the unbundling and privatization reforms in China and use a difference-in-differences (DD) strategy to deal with identification. We rely on a unique firm-level dataset that contains comprehensive information on firms' pollution records and electricity generation. We find that privatization significantly and substantially reduces power plants' air pollution intensity, and the underlying channels are power plants' cost reduction and efficiency enhancement, increased electricity generation, and better compliance with environmental regulations. Unbundling, on the other hand, has no significant effects on power plants' air pollution, but opens up the gate for privatization. Our findings document an effective and environmentally friendly pathway for electric industry restructuring in developing countries.

Methods

To identify the effect of electric industry restructuring on power plants' pollutant emissions, we construct a DD framework and compare the polluting behavior of state-owned and private power plants before and after the unbundling and privatization policies. A potential concern is about the nonrandom assignment of privatization. In other words, power plants that are privatized may be systematically different with power plants that are not privatized, and this pre-existing difference might affect privatized and other power plants' behavior differently. To alleviate this concern, we first carefully characterize significant determinants of privatization documented by Bai et al. (2006), and then control these pre-reform characteristics in a flexible function form in the specification.

The identification assumption associated with our specification is that conditional on the fixed effects and controls, our regressor of interest is uncorrelated with the error term. We further carry out three tests to check the key identification assumption. First, we present the event study estimates to test the parallel trend assumption of our DD specification. We include the interaction between the electricity restructuring reform and year indicators and analyze the year-wise evolution of plant-level industrial air pollution intensity differences before and after the electricity restructuring reform. Second, recent research suggests that DD with variation in treatment time may still be biased even if the parallel trends assumption holds (Goodman-Bacon, 2021). We therefore implement the DD with multiple periods estimator proposed by Callaway and Sant'Anna (2020). Finally, we construct a Bartik-style instrumental variable (IV) for privatization. The baseline, Callaway and Sant'Anna, and IV regression results are of similar pattern.

Results

All regressions include plant fixed effects to control for time-invariant unobservables and year fixed effects to control for nationwide shocks. We further include plant controls in Columns 4-6. Estimates are consistent across all specifications, which indicates that the unbundling reform has an insignificant effect on power plants' air pollution intensity, while privatization reform significantly decreases power plants' air pollution intensity. Exploiting the most conservative estimate in Column 6 for interpretation, the OLS estimate indicates that, privatized power plants have 11.10% lower air pollution intensities after the reform, compared to the always and never privatized power plants.

We next conduct a series of robustness tests to further address concerns about the identification assumptions and corroborate the findings. These include ruling out alternative explanations, using other measurements, the exclusion of simultaneous shocks or policies, considering firms' entrance and exit, adding city controls, etc. The results suggest that our findings still hold in each case.

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Interconnecting Northeast Asia towards Renewable Transition of Power Sectors: Gains and Losses for Major Economies

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Abstract

Under the rising pressure for low carbon energy transitions, interconnecting local power grids for interstate power trade allows to share reserve capacity and redistribute intermittent renewable energy across time zones, contributing to regional sustainability. Although the idea of Asia Supergrid to interconnect Asian countries into a singular electric grid has long been highlighted as a way to accelerate renewable transitions, the region faces various obstacles for its implementation including wide economic gaps across countries and lack of cohesive political body to regulate different policy priorities of countries.

This paper suggests a phased approach for Asia Supergrid to interconnect the three major economies in Northeast Asia (NEA) including China, South Korea and Japan. Considering these countries have shown different levels of interests in grid interconnections and interstate power trade, we test 4 scenarios that differ in countries to be interconnected for power transmissions and compare trade impacts: 1) autarkic generation, 2) trilateral trade among China North, South Korea and Japan West and 3) two bilateral trade models that interconnects only China North and South Korea, and 4) South Korea and Japan-West. Using a linear programming model that minimizes total energy system costs to meet hourly power demand of the three urban nodes for year 2050, this paper assesses economic and environmental competitiveness of different trade models affected by a varying level of CO_2 prices. Building on a stream of literature that have examined Asia region wide interconnections, this study

contributes to understanding economic and environmental gains for trade participation for individual major economies in NEA.

Methods

We use a linear optimization model to minimize total energy system cost of the three nodes to meet nodal electricity demand in year 2050. The year 2018 is the base year that we assess existing generation/storage capacity as well as cost information of each technology option from. As electricity market of China and Japan are fragmented into sub-national grids, assessment of current supply ability of the adjacent nodes that interconnect three countries (China north, South Korea and Japan West) requires special treatment of generation capacity data. We start from plant level data (Enerdata 2018) for each country and sort out plants in the corresponding node based on each plant's location information for aggregation by technology to finally have nodal generation/ storage capacity.

Recognizing electricity market is a unique place where supply meets demand on an hourly basis, we set hourly power demand for each month in 2050. For each node, we acquire data on a 2050 peak demand estimate from government energy plans and historical hourly power demand. We get the annual peak from the hourly power demand data in 2019 and set it the value of 1 and then convert all other hours in terms of peak ratio, so we multiply them by 2050 peak load for 2050 hourly power demand. By having an hourly demand pattern for each month 2050 and node, we test model's ability in responding to changing power needs over a day across seasons and time zones.

Addressing variability of solar and wind energy in the model is done using hourly output profiles. We acquire solar and wind output profiles of China north and Japan west from existing study (Otsuki et al 2018) and those of Korea from renewable power generators (Korea Southern Power 2019 and Korea Southeast Power 2018).

Cost information of all technology options are collected from various institutional publications including International Energy Agency and Organization of Economic Cooperation and Development.

Results

Our results indicate that trilateral model yields the lowest total cost at all levels of carbon prices (from $0-$180/ton of CO2 emitted) while accelerating low carbon transitions on the regional level at the same time. Furthermore, South Korea and Japan largely benefits from trilateral trade in terms of reduced electricity generation cost and fossil fuel consumptions compared to other scenarios.

Ambitious carbon pricing is essential to ensure renewable transitions and equitable trade impacts for all participating nodes.

Above CO2 price of 60$, China's trade participation either in bilateral or trilateral improves the cost competitiveness of renewable energy compared to autarkic generation and achieves highest renewable penetration in trilateral model. More importantly, low levels of carbon prices affect China to consume more fossil fuels for extra power generation for exportation. At co2 prices above 90 USD/ton of CO2, however, trilateral model yields the lowest fossil fuel consumptions for all participating nodes including China north.

Investigating Market Designs that Enhance Electricity Market Incentives for Flexible Performance

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Abstract

Electricity markets differ from other commodity markets because electricity grid stability relies on maintaining an instantaneous balance between energy consumption and generation. To accomplish this, power systems need operational flexibility, i.e., the ability of generating resources to rapidly adjust their output in reaction to variations in operating conditions that change the system demand or supply. Continued additions of Variable Renewable Electricity (VRE) to grids increases the demand for operational flexibility. At higher VRE penetration, load-following generators are expected to provide more frequent and shorter duration on/off cycles and ramps.

Conventional, competitive electricity markets in the U.S. suffer from shortcomings that suppress energy-market prices for load-following generators and fail to incentivize their flexible performance. Daraeepour *et al.* 2021 shows that growth in the need for flexibility driven by higher wind penetration levels exacerbates these shortcomings. In addition, operating more flexibly increases a conventional generator's costs as a result of greater wear and tear, higher heat rates, and higher forced outage rates. At the same time, when generators operate more flexibly, the price suppressive effect of conventional marginal pricing increases. Growth in price suppression enlarges the gap between actual energy-market returns and those needed to recover flexibility cost impacts and incentivize flexible performance.

Inadequate incentives not only discourage flexibility enhancements among existing assets, but also motivate load-following generators to withhold their inherent flexibility, which increases VRE integration costs and degrades the economic efficiency of the market. This paper investigates the merits, relative to conventional marginal pricing, of two alternative market design constructs in enhancing energy-price formation efficiency and incentivizing greater operational flexibility: convex-hull pricing and load-following products. We assess these constructs for three levels of wind energy contributions to the generation mix. For the analysis, we use a custom-built model to simulate PJM's hourly electricity market outcomes under the alternative market designs. Our study shows that convex-hull pricing is the most effective option for reducing the price-suppressive effects of the conventional design and for incentivizing greater flexibility, and load-following products achieves 50% to 60% of the price-suppression reduction and nearly the same flexibility incentives enhancement as convex-hull pricing. The performance of load-following products improves as wind penetration grows and almost matches that of convex-hull pricing when wind penetration is higher than 20% of generation. Our study shows that load-following products not only improve pricing efficiency, but also improve cycling and ramping patterns of conventional generators in ways that reduce the cost impacts of operating flexibly, enhance pricing efficiency and load-following generators' profitability, and reducing their reliance on uplift payments.

Methods

This study uses the Electricity Market Simulation Tool (EMST) to simulate the day-ahead market outcomes of the PJM grid under different market designs and wind penetration levels. EMST was originally developed (Daraeepour et al. 2019) to simulate the operation of day-ahead and real-time markets for a year-long period with different designs that account for the characterization of uncertainty in the day-ahead market clearing design, including load-following capability products, stochastic residual unit commitment, and stochastic market clearing. EMST was further extended (Daraeepour et al. 2020) to include alternative pricing mechanisms, including primal approximations of convex-hull pricing.

In this study, we have configured EMST to simulate three different market designs. The first design represents PJM's conventional energy-market design, henceforth called CD. The second design, henceforth CD-AP, uses Advanced Convex Primal Pricing to approximate convex-hull prices for settling energy transactions rather than conventional marginal prices. The third design, henceforth CD-LFP, augments the conventional design with load-following products. For each individual design, EMST simulates the day-ahead market operations for each day and uses its commitment and dispatch outcomes to initialize simulations of the subsequent day.

During each operating day EMST runs two modules to simulate market operations under each design. The first module "ISO's Welfare-Maximizing Operations" determines the socially optimal quantity schedules and prices. CD and CD-AP use the same unit commitment model, which is broadly similar to the conventional models used by ISOs, which minimizes the total cost of supplying demand over a twenty-four-hour horizon subject to technical characteristics of generators and market-clearing conditions. The model includes some additional constraints that relax the integrality of commitment variables in the CD-AP case to enable approximating convex-hull prices in the pricing stage. Detailed formulation of the tight unit commitment formulation and the required additional constraints for pricing are presented and described in (Daraeepour et al. 2020). CD-LFP uses a version of the unit commitment model that includes an additional formulation for modeling load-following products (Daraeepour et al. 2019). The second module "Settlement Process to Ensure Incentive Compatibility" uses two models to calculate profit-maximizing commitment and generation schedules and the uplift payments that make generators indifferent to following the welfare-maximizing or profit-maximizing schedules for each operating day and each market design.

The economic implications of conventional and alternative energy pricing mechanisms are examined using a 12% capacity-scaled version of PJM's supply resource mix combined with synchronous wind generation and system load data from the Bonneville Power Administration (BPA) as developed by Daraeepour et al. (2019). The scaled system has a peak load of 18500 MW, 67 prototypical conventional generators totaling 20000 MW of installed capacity, and a wind farm whose generation represents the aggregated amount of hourly wind supply in the PJM footprint. (Daraeepour et al. 2019) gives detailed descriptions of the technical and cost characteristics of the generators.

Market operations under CD, CD-AP, and CD-LFP market designs are analyzed for three wind-penetration cases. Case 1, Case 2, and Case 3 correspond to 10%, 20%, and 30% wind penetration, respectively, in ensuing discussions.

Results

This comparative analysis of market designs based on convex-hull pricing (CD-AP) and on conventional pricing with modification for load-following products (CD-LFP) shows that both designs significantly address shortcomings in energy-price formation under conventional marginal pricing market design (CD) and enhance incentives for flexible performance. CD-AP pricing is superior in enhancing the price formation process by driving significant reductions in the number of unrepresentative price events and in uplift payments while enhancing market remuneration of flexibility. CD-LFP increases average energy prices such that marginal price suppression is 50% to 60% less than under CD, depending on the wind penetration level. Although CD-AP and CD-LFP do not fully overcome price suppression seen under CD, they are efficient in enhancing market incentives for flexible performance. As wind penetration increases, CD-LFP reduces uplift payments and increases load-following generators' profits and their ability to recover ramping costs nearly as much as under CD-AP. For instance, in Case 1, CD-LFP and CD-AP result in five- and eight-fold increase in total profit for load-following generators with respect to the profits under CD, but in Case 3, they both result in nearly nine-fold increase in the total profit for load-following generators with respect to that in CD.

Considering practical and regulatory barriers of implementing CD-AP, the above outcomes suggest that CD-LFP is a feasible practical alternative for enhancing energy-price formation and market remuneration of flexibility. Our analysis shows that under both CD-AP and CD-LFP, load-following generators with medium range capacity factors, which supply the largest share of load-following requirements, recover their ramping costs at 10% to 30% wind penetration levels. At 30% wind penetration, the two market designs provide comparable performance in reducing uplifts and enhancing market remuneration of flexibility.

A major advantage of CD-LFP exposed in this study is its effect on dispatch outcomes. Load-following generators are positioned to follow net-load fluctuations with fewer number of cycling and ramping events. This increases their market profits and improves recovery of costs incurred during load-following operation. Capacity factors for load-following generators are also slightly increased, which further increases their energy-market profitability.

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Rethinking the Role of Financial Transmission Rights in Wind-Rich Electricity Markets in the Central U.S.

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Abstract

In the United States, most wind power capacity has been deployed in the wind-rich central region. Transmission congestion within this large region causes spatial variation in wholesale power prices—called the basis—that can unpredictably reduce wind plant revenue and, hence, possibly slow deployment. We use historical pricing and generation data from three central U.S. markets to show that wind plants are more-susceptible than thermal generators to congestion-related basis risk. Moreover, while most thermal generators can effectively hedge any basis risk by purchasing conventional financial transmission rights (FTRs), these fixed-volume FTRs are not a good match for variable wind generation. More-effective hedging mechanisms—for example, an FTR whose volume varies with wind plant output—may be required to support those generators most-impacted by congestion, and to promote continued investment in variable generation resources in congested markets.

Methods

We use historical wholesale power market prices and generation profiles to quantify both the basis risk and—assuming various FTR designs—the residual basis risk across multiple generation technologies in the central region of the United States. Historical wholesale market data reflect actual system conditions and constraints associated with ensuring that supply and demand are balanced across time and, in nodal markets that are common in the U.S., across thousands of individual locations in the grid.

Using prices from both the nearest node and nearest major trading hub to the generator location, along with historical plant-level generation profiles, we calculate the node minus hub basis risk for individual plants—both on average over the course of a year and in terms of monthly volatility. We then introduce FTRs of varying design to hedge against basis risk and its volatility. Any basis risk that remains after accounting for the FTR payout is known as "residual basis risk," which we once again quantify on average and in terms of monthly volatility for each FTR design.

Results

This research evaluates the basis risk and residual basis risk for different generating technologies under various types of FTRs. The primary contributions of the paper are (1) an empirical comparison of the basis risk of wind energy to other conventional generation types, (2) an empirical assessment of the effectiveness of fixed-volume FTRs at hedging the basis risk of wind and other generation types, and (3) an evaluation of the effectiveness of alternative FTR designs at improving the ability to hedge the basis risk for wind energy.

Our analysis finds that transmission congestion-related basis risk—price difference between locations—most impacts wind energy, and its impacts are growing. Thermal generators are less impacted by basis risk, and many can use fixed-volume FTRs to effectively hedge their basis risk. The variable nature of wind generation, on the other hand, is not a good match for the fixed-volume FTR, leading to substantial unhedgeable residual basis risk. The inability to hedge this risk with conventional FTRs makes the products less attractive to wind plants. Continued investment in variable resources in congested markets may require improving hedging mechanisms to manage basis risk. The implication is that the reforms to FTR markets, including introducing FTR products whose volume varies with wind power, could create a more effective hedge for those most impacted by congestion.

Competition in Financial Transmission Rights Auctions

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Abstract

Financial derivative markets can facilitate desirable outcomes including efficient risk transfer and price discovery. One hallmark of a well-functioning derivative market is liquidity. A highly liquid market is conducive to a competitive outcome –transactions can occur with small transaction costs which allows new information to be readily incorporated into the market price. Conversely, markets with low liquidity do not allow for efficient risk transfer and produce market clearing prices that may not incorporate all available information. Generally speaking, illiquid markets are inefficient and send distorted price signals about the value of the underlying asset.

Financial Transmission Rights (FTRs) are a financial derivative in the electric power industry which are used to manage basis risk in the spot energy market. FTRs have existed since the inception of competitive wholeasale electricity markets and are often cited as an essential component of the overall electricity market design. FTRs serve the dual purpose of providing market participants (e.g., load-serving entities, generation owners, power marketers) with a basis hedge product and a means by which the system operator redistributes congestion rent collected in the energy market.

While FTRs are a useful product for many market participants, they present challenges to regulators and electricity customers. For example, FTRs can be used in cross-product manipulation schemes with other derivative products (Lo Prete et al., 2019). Regulatory issues aside, efficient FTR auction markets are critical because the cost of any auction inefficiency is ultimately borne by electricity ratepayers. Ratepayers bear the cost of auction inefficiencies because they swap a future payment stream in the spot energy market for fixed revenue in the FTR auction. If the auction market is inefficient, then the fixed revenue payment from the FTR auction will be biased downward from the future payment outflows. The downward bias of FTR auction revenue has been documented in a variety of settings (Opgrand et al., 2022; Olmstead, 2019; Adamson et al., 2010). While the prior literature documents a downward bias in FTR auction prices, they do not address whether the downward bias in auction prices is the result of efficient risk-adjustment to auction prices or because the market suffers from a structural issue, such as low liquidity or lack of competition. Therefore, this paper is concerned with studying

market microstructure properties of the FTR auction market, and seeks to address whether the auction in which FTRs are sold is competitive or not.

Methods

There is no single metric which definitively establishes whether an FTR auction is competitive or not. Rather, competitiveness must be analyzed from a variety of perspectives, and the assessment of competitiveness is based on the totality of evidence. In this paper, we introduce three perspectives from which competitiveness can be analyzed: 1) constraint-based HHI, 2) counterflow clearing, and 3) orderbook depth. Constraint-based HHI measures the concentration of cleared capacity on a transmission constraint in an FTR auction at the participant level. If HHI is high (e.g., > 2,500), then the bidding activity for the constraint is potentially non-competitive and warrants further investigation. Counterflow clearing measures how much bidding activity there is *against* a given constraint. Conceptually, increased demand for prevailing flow on a constraint creates upward pressure on prices, whereas counterflow clearing measures downward pressure. If there is little or no counterflow clearing on a given constraint, then it is less likely that the equilibrium price is competitive. Finally, orderbook depth is a way to visually and analytically inspect auction market liquidity. If there is little market depth, then the market price is volatile and can change dramatically with the addition or subtraction of one bid.

Results

Empirical application of methods to real-world data is in progress.

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Coalition Stability in PJM: Exploring the Consequences of State Defection

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Abstract

Using a novel simulation tool, we investigate the effects created by a U.S. state defecting from the wholesale electricity market in PJM, an organized electric grid in the eastern United States, on the states that remain in the coalition. We find, generally, that if a net-importing state defects from the wholesale energy market, the remaining states' producers are worse off and the remaining states' consumers are better off. The opposite effect takes hold if the defecting state is a net-exporter. Furthermore, we find evidence that defection impacts the remaining states' climate initiatives. The effectiveness of electric vehicle and solar photovoltaic policies are conditional on if a state defects and which state does the defecting. Our simulations suggest that, for state legislatures pursuing these environmental goals, the best strategy to adopt is to pass laws that are both geographically targeted and flexible.

Methods

We seek to simulate PJM's wholesale market as it was in 2019 with generator offers, merit order, ancillary services, make-whole payments and congestion-related effects all playing a role in which generators get dispatched and what price clears in each hour of the year. To measure the impacts of a state defecting from the consortium, we also simulate the removal of a single state from the broader PJM organization. In those defection scenarios, we simulate PJM without the supply or demand of the defecting state.

To initialize our model, we gathered detailed data on the demand for electricity in PJM, the set of generators deployed in PJM, fuel costs associated with these generators, renewables generation in PJM's footprint, energy storage assets, transmission constraints present between modeled PJM zones, imports/exports between PJM and external grid systems, imports/exports between states within PJM, a method for determining market-based costs of emissions, and a process for removing individual states from the simulation.

We first begin by simulating PJM's wholesale electricity market as it was in 2019. This "Base Case" is compared to five different state-exit scenarios: New Jersey defects, Maryland defects, Virginia defects, Pennsylvania defects and Illinois defects. We chose New Jersey and Maryland for the public comments indicating these states' distaste for recent developments in PJM's market rules. Our choice of Virginia arises because it is the largest importer of electricity in PJM and we wanted to explore the impact of defection by that extremum. Pennsylvania and Illinois, as the two largest exporters in PJM, were simulated as defectors as well. In comparing these defection scenarios to the Base Case, we can measure how one state's absence can influence the outcomes in other states in the consortium.

Finally, we compare the marginal increase (decrease) in grid CO_2 emissions from an electric vehicle (4 kW solar panel) under the Base Case to different state defection scenarios. These state exits not only change producer surpluses and consumer wholesale costs, but they also impact the marginal plant in any given hour of the year. Thus, the marginal CO_2 emissions from an increase or decrease in load would have differing impacts under our different simulation scenarios. States looking to exert some impact on climate change mitigation might change their strategy, conditional on another state exiting from the wholesale electricity market. In sum, we find that fracturing consortiums have spillover effects on both welfare outcomes and on the ability to enact policies with maximum desired effects.

Results

We simulate the impact of the five different state defection scenarios for the states that remain in PJM post-defection on the following factors : total in-state generation, the average cost to serve load, the market-based emissions costs, and producer profits. We use these calculations to begin the process of a welfare calculation for each state that remains in a post-exit scenario. Our measure of producer surplus and our measure of consumer surplus indicate illustrates the tradeoffs made by states between producers and consumers. For nearly all states in all scenarios, what is good for producers is bad for consumers and vice versa. Whether a state is better or worse off because of a defection is a broader welfare question that must include some equity considerations. Our simulations predict two distinct exceptions to this producer/consumer tradeoff: Delaware is unambiguously worse off if Pennsylvania defects, and DC is unambiguously better off if New Jersey defects.

We also explore the impact a state defection has on the remaining states' abilities to pursue climate initiatives. We take cues from the existing literature on how marginal additions to the fleet of electric vehicles or to the installed capacity of solar panels would increase or decrease electricity-based CO_2 emissions, respectively. We compare the marginal increase (decrease) in grid CO_2 emissions from an electric vehicle (4 kW solar panel) under the Base Case to different state defection scenarios. States looking to exert some impact on climate change mitigation might change their strategy, conditional on another state exiting from the wholesale electricity market. In sum, we find that fracturing consortiums have spillover effects on both welfare outcomes and on the ability to enact policies with maximum desired effects. Our general results suggest that electric vehicle and solar panel incentives should be geographically targeted and flexible to ensure these policies have maximum effectiveness.

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Using Temperature Sensitivity to Estimate Shiftable Electricity Demand: Implications for power system investments and climate change

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Abstract

Growth of intermittent renewable energy and climate change make it increasingly difficult to manage electricity demand variability. Transmission and centralized storage technologies can help, but are costly. An alternative to centralized storage is to make better use of shiftable demand, but it is unclear how much shiftable demand exists. A significant share of electricity demand is used for cooling and heating, and low-cost technologies exists to shift these loads. With sufficient insulation, energy used for air conditioning and space heating can be stored in ice or hot water from hours to days. In this study, we combine regional hourly demand with fine-grained weather data across the United States to estimate temperature-sensitive demand, and how much demand variability can be reduced by shifting temperature-sensitive loads within each day, with and without improved transmission. We find that approximately three quarters of within-day demand variability can be eliminated by shifting only half of temperature-sensitive demand. The variability-reducing benefits of employing available shiftable demand complement those gained from improved interregional transmission, and greatly mitigate the challenge of serving higher peaks under climate change.

Methods

In this paper we estimate potentially shiftable heating and cooling demand using a “top down” approach that links hourly electricity demand across the continental United States to fine-grained estimates of hourly temperature over space and time. We use a flexible functional form to account for shifts in demand that arise from seasonal, day of week, and time-of-day effects, as well as geospatial variations in climate, which can factor into temperature sensitivity. Conditional on these factors, weather variation is arguably conditionally exogenous—as if randomly assigned—and thereby constitutes a viable natural experiment to identify temperature-sensitive load that is likely shiftable. We cross-validate the model by predicting demand in out-of-sample years, and show these predictions to be highly accurate. We then use the model to predict the share of temperature-sensitive demand in each hour and region.

Assuming different shares of the estimated temperature-sensitive load in each hour can be shifted within each day, we determine alternative feasible “flattened” demand profiles. At least in a conventional system, the degree to which demand can be flattened comports with the cost of the overall system, holding total demand fixed. We show how much reshaping demand in this manner can serve to flatten load with and without transmission across regions within and between the three interconnects in the United States: East, West and ERCOT. Finally, we predict demand and estimate shiftable load under a uniform climate change scenario in which all temperatures increase by 2C.

Data: Cleaned hourly electricity demand from the Energy Information Administration (EIA) form 930, were obtained for all balancing authorities for three calendar years, 2016-2018. For both the Eastern and Western interconnects, we aggregated hourly load into 15 regions. We aggregated balancing authorities based on spatial overlap of coverage areas as indicated in shape files obtained from the Department of Homeland Security.

Gridded air temperature data at two meters of elevation were obtained from the the National Oceanic and Atmospheric Administrations North American Regional Reanalysis data (NARR). These data give three-hour measures on a roughly 30 kilometer grid. We linearly interpolate the three-hour data to convert to hourly data. Two key weather measures are used, cooling degree hours (CDH) and and heating degree hours (HDH).

To merge these temperature measures with the regional demand data, we overlaid the gridded weather data with roughly 1 km gridded population data, and calculated population-weighted averages over each region.

Results

- If half the temperature-sensitive load is shiftable (alpha = 0.5), regional daily peak load can be reduced by an average of 10.1%, daily base load increases by an average of 22.2%, daily SD falls by an average of 76.9%, and 17.9% of region/days can be flattened completely.

- Electricity demand is more strongly associated with CDH than with HDH, while the amount of CDH and HDH varies regionally, with more of both in Eastern regions and ERCOT, which helps to explain why these regions have more temperature-sensitive load and more potential flattenability.

- When shiftable load is paired with perfect transmission between regions, average daily load variability (SD) can be reduced by 84.9% when all regions within each interconnect are pooled and by 94.3% when all regions are pooled nationwide, assuming just half the temperature-sensitive load is shiftable.

- Assuming half of temperature-sensitive demand can be shifted within days (alpha = 0.5), the overall SD of demand for a typical region can be reduced by roughly 25%.

- Shifting of temperature-sensitive load can do more to reduce overall variability than perfect transmission.

- We find a 2C increase in temperature causes average daily peak demand to increase from 118.6% to 122.5% of historic daily mean and from 118.2 to 121.9% of the historic overall mean, while the 99th percentile of peak load increases from 179.4% to 191.0% of the the overall historic mean.

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How Much Does Latin America Gain from Cross-Border Electricity Trade in the Short Run?

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Abstract

Regional or cross-border trade of electricity would be beneficial for all trading partners for multiple reasons. However, cross-border electricity trade in Latic America is limited, and the potential benefits have been forfeited. This study estimates the potential savings on electricity supply costs if 20 Latin American countries allowed unrestricted trade of electricity between the borders without expanding their current electricity generation capacity. Two hypothetical electricity trade scenarios – unconstrained trade of electricity between the countries within the Andean, Central, and Mercosur subregions and full regional trade involving all 20 countries are simulated using a power system model. The study shows that the volume of cross-border electricity trade would increase by 13 and 29 percent under the subregional and regional scenarios, respectively. The region would gain US$1.5 billion annually under the subregional scenario and almost US$2 billion under the full regional scenario. More than half of this gain would be realized by the Andean subregion under both scenarios.

Methods

Regional or cross-border electricity trade entails several economic and environmental benefits, including optimal use of electricity generation resources across the borders; hourly cross-border electricity trade utilizing differing load curves between the countries; sharing peak load and reserve margins, enhancing the system reliability; facilitating clean energy trade to reduce emissions of greenhouse gases (GHGs) and local air pollutants and finally reducing the cost of electricity supply. The total benefits of the regional electricity trade could be much larger than the costs to realize it (e.g., Rogers and Rowse, 1989; Bowen et al., 1999; Yu, 2003; Pineau et al., 2004; Gnansounou et al., 2007; ESMAP, 2010; Timilsina and Toman, 2016; Timilsina and Toman, 2018; Timilsina and Curiel, 2020). Limited regional electricity trade has been exercised in Latin America (LAC region), multilaterally in Central America (SIEPAC) and multilaterally or bilaterally in other parts, such as Brazil-Uruguay-Argentina (Del Campo, 2017). However, the volume of cross-border electricity trade in the region accounts for less than 5% of the total regional generation. Several countries in the region have excess capacities; their load profiles differ significantly, indicating cross-border electricity trade opportunities without adding new capacities for electricity generation. This study estimates the gains from sub-regional and regional electricity trade in Latin America utilizing existing generation capacities (e.g., day-ahead, intra-day, and balancing services).The study first highlights cross-border trading opportunities in the region by showing (i) differences in hourly and seasonal load curves across the countries; (ii) electricity price differences between the countries; (iii) excess capacities in different countries that can be utilized; (iv) differing fuel mixes indicating the potential clean energy trade and (v) difference in average as well as marginal costs across the countries. It then uses the World Bank's electricity olanning model (EPM) to simulate hourly electricity generation and trading potential at the sub-regional and regional levels. We developed three scenarios – Baseline, Sub-Regional trade and Regional trade. Under the baseline scenario, each country dispatches its power plants following the merit-order rule and meets its demand in 2020. It also accounts for existing cross-border electricity trading facilities. The Sub-regional trade scenario assumes unconstraint cross-border electricity between the countries within three sub-regions: Andean sub-region (Bolivia, Colombia, Ecuador, Guyana, Peru, Suriname and Venezuela), Central sub-region (Belize, Costa Rica, El Salvador, Guatemala, Honduras, Mexico, Nicaragua and Panama) and Mercosur sub-region (Argentina, Brazil, Chile, Paraguay and Uruguay). The regional trade scenario considers unconstraint electricity trade across all countries in the LAC region. We collected hourly load data in 2020 (8784 hours) for 20 LAC countries to develop hourly load profiels. Other data used are fuel and electricity prices, peak loads, generation capacities by technology type (10 types of technologies) and existing cross-border interconnection capacities.

Results

The study finds that the existing volume of electricity trade (baseline scenario) in LAC is approximately 4% of the regional generation. It would increase to 13% and 29% under the sub-regional and regional scenarios, respectively. The Andean region realizes the highest increase in electricity trade volume; the traded volume of electricity in this sub-region accounts for 0.2% and 33% of the total sub-regional generation in the baseline and sub-regional scenario, respectively. The ratio of traded electricity to total generation would almost double from the baseline scenario to the sub-regional scenario in the Central and Mercosur sub-regions. In terms of trade value, the region as a whole would gain US$1.5 billion annually under the sub-regional scenario and almost US$2 billion under the full regional scenario. More than half of this gain would be realized by the Andean sub-region under both scenarios. About one-third of the total regional gains would go to the Mercosur sub-region. The Central region would gain 12% and15% of the total regional gains under the sub-regional and full regional scenarios.

Note that these are short-term benefits by utilizing existing capacities in different countries. The size of the total benefits would be larger in the long run.

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How to make money? Electricity Market Design Without Marginal Operating Costs

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Abstract

This paper examines the feasibility of current wholesale market pricing mechanisms to support a market supplied solely by intermittent and non-dispatchable sources generating with zero-marginal costs (like wind and solar), plus storage. After introducing and discussing a comprehensive list of goals an optimal market mechanism must achieve, this paper proves that current pricing mechanisms will not satisfy these goals. Using simulations based on the German and ERCOT market data, this paper proposes a modified pricing mechanism that solves some but not all the issues of spot price auctions and concludes that the perfect pricing mechanism is yet to be found.

Methods

First, I clearly define 9 goals for a sufficient market design, inspired by the literature on mechanism design. Next, I simulate the markets as a cost minimization problem with side conditions, using the market data from Germany and ERCOT/Texas. As we show, storage owners are confronted with a multi-unit sequential auction, for which equilibrium bidding strategies are not necessarily available in the game theory literature. A substantial part of the paper is to discuss a novel recursive equilibrium bidding strategy and two computationally faster approximations. Using these bidding strategies and the real life market data, we simulate the market outcomes.

Results

Spot auctions perform poorly on our 9 goals of a mechanism and do not provide sufficient revenues to solve the missing money problem. As especially storage cannot earn sufficient revenues, we use a modified version of the Energy Cum Operating reserve market initially proposed by Hogan (2005) to overcome this issue. While it certainly provides sufficient revenues for storage owners, it is not the panacea.

Energy & developing countries

Choice to Make-the Impact of Urbanization on Residential Cooking Fuel Transition in China

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Abstract

Transition of developing country households from traditional biomass fuels to clean fuels has recently received growing attention. Indoor air pollution from incomplete burning of biomass fuels has become a major driver of respiratory diseases and child mortality in developing countries. Rapid urbanization in emerging economies plays an important role in promoting fuel transition in residential energy consumption. Urbanization therefore is also strongly connected with the environmental and health problems related to the use of traditional biomass fuels. China, one of the world's largest economies, has implemented numerous regulations and policies to promote urbanization via internal migration. The consequent expansion in city administrative boundaries and associated infrastructure development has substantially changed the pattern of residential energy demand. Nevertheless, although 71.3% of the population in China have access to cleaning cooking facilities (IEA, 2020), a high percentage of households still use coal and firewood as their primary cooking fuel.

The first goal of this study is to model household cooking fuel choice in a way that will allow us conduct counterfactual experiments to predict how energy infrastructure expansion in China is likely to change household cooking fuel choices. The study also investigates how residential energy choice responds to policy-driven natural gas price changes. The last goal of the study is to investigate the effect of reform of the household registration system on residential energy choice. The Chinese government began the "reform of the household registration system" in 2014. Urbanization modifies household fuel choices through multiple channels. For instance, the household's income typically increases following internal migration. Households in urban areas also have better access to clean modern fuels due to infrastructure development. We can use our structural model to tease out these separate effects. Additionally, the structural model also allows us to predict the welfare effects of changing access to an individual product (i.e., the change in consumer surplus that would result if the biomass fuels are removed from the choice set).

Our proposed research makes a number of contributions to the substantial body of research studying the determinants of the household cooking fuel choices in developing countries (e.g., Hou et al., (2017); Komatsu et al., (2013); Alem et al., (2016); Paudel et al., (2018)). Most of these studies concentrate on the influences of household demographics or changes in the price of fuel. Furthermore, very few existing studies use a structural model or investigate the effect of urbanization on residential energy demand. This study adopts a structural estimation to facilitate study of counterfatcural situations where the use of reduced form approaches would be subject to the Lucas critique. The ultimate objective of the paper is to answer the following questions: besides the commonly examined determinants (e.g., family size, income level, household education level) of household fuel choices, can we identify some

additional explanations for residential energy consumption? How do the two policies related to urbanization mentioned above affect household fuel choices in China?

Methods

In this paper, we study household's cooking fuel choices across four categories: firewood, coal, gas (i.e., Pipeline gas and LPG), and electricity. Other types of fuels (e.g. solar energy, kerosene, methane from biological sources) are considered as the outside choice. Our panel data come from combining the China Family Panel Studies (CFPS) surveys in 2010-2018. The data contains a range of individual and household characteristics of the respondents. Most importantly for our empirical analysis, the survey contains information about consumer consumption decisions(i.e., the major fuel for cooking). To these household data on choices, we match information on the prices, the market level characteristics to each household. The complete data set is complied from four sources: China price information network, the individual level demographic variables from the CFPS survey, and province-by-year demographic information from the National Bureau of Statistics of China and the China City Statistical Yearbooks.

Given the discrete nature of household-level demand, following the model in Goolsbee and Petrin (2004), Gentzkow(2007), and Liu et al.,(2010), we choose a discrete choice demand specification. Index the variables by household (i=1,...,I), product (j=0,1,...,J), time(t=1,...,T), and province (m=1,...,M). The total number of markets is equal to M∗T. Note that household i chooses among J+1 different options for their major cooking fuel in time period t. The option 0 indicates the outside option. Define the price for fuel j in market m at time t as p_{mjt}. Use $\mathbf{x_i}$ to represent the vector of observed household characteristics (e.g. household size, migration status, income level...etc). The vector of market characteristics lm includes length of natural gas pipelines in the province as well as the percentage of built-up area in province m at time t. Note that some of the attributes of consumers and products are not observable in the data in some years. The indirect utility of household i lives in province m using cooking fuel j at time t is decomposed into the following parts:

$U_{ijmt} = V(x_{it}, l_{mt}, t) + \Phi(j \mid y_{i,t-1}) + (\gamma\ p_{mjt} + \sum^{K}_{g=2} \gamma p_{mjt} d_{git} + \sum^{K}_{g=1} \zeta_g d_{git}) + e_{ijmt}.$

The first term V(.) on the right hand side of the equation is the base line utility that consumer i obtains by choosing product j at time t, where $V(x_{it}, l_{mt}, t) = \beta'_j x_{it} + \delta t + \alpha'_j l_{mt} + v_{ij} + \eta_{imt}$. The second term $\Phi(.) = \theta 1(y_{i,t-1=}j) - \kappa\ 1(y_{i,t-1} \neq j) C\_\{y_{i,t-1} \neq j\}$ represents the state dependence effect, more specifically, it captures the potential effect of the choice of fuel in time t-1 have on consumer decision in time t due to switching cost. The last two terms corresponds to the price effect, the income effect and the mean zero stochastic term eijmt. We assume that the error term e_{ijmt} is distributed as a type I extreme value function. We then consider a random coefficient logit model, which allows heterogeneity in preference parameters. Following Gentzkow(2007), we assume v_{ij} has a J-dimensional multivariate normal distribution, and η_{imt} has a two point discrete distribution. The parameters are estimated using simulated maximum likelihood(SML).

Results

Before imposing a specific parametric form on the consumer utility function, we first look for preliminary evidence of the determinants of residential cooking fuel choices. We applied a simple multinomial logit regression on the household cooking fuel choices in 2010, 2012, 2014, 2016, 2018, respectively. Just based on this preliminary simple regression, we can see the influence agriculture household registration status (Hukou) and internal migration have on the residential choices. In general, the agriculture Hukou influences the consumer's choice on gas and electricity negatively, while internal migration and natural gas pipeline length influences consumer choice on gas positively. This is consistent with our expectation since people who hold agriculture Hukou usually live in a rural area and are more likely to have access to biomass fuels.

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Planning for a Just Renewable Energy Transition in India

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Abstract

Emerging research shows that the falling cost and widespread availability of renewable energy have great promise in economically reducing CO2 emissions. Lu et al (2020) describes how wind and solar in India could meet 80% of anticipated 2040 power demand and lead to a reduction of 85% in CO2 emissions, dramatically reducing the country's reliance on coal. However, planning for high-penetration futures of renewable energy sources in India must also consider the unique regional political constraints, socio-economic conditions, and availability of labor that might impact the future of India's clean energy transformation. Our aim is to answer pertinent questions regarding the extent to which prioritizing political suitability influences renewable energy potential in India. For instance, locations close in proximity to high-voltage transmission lines provide economic benefits to distribution companies associated with a lower cost of providing transmission access and a grid connection. We examine wind and solar capacity factors, energy potentials, and the levelized cost of energy (LCOE) with existing transmission infrastructure of Indian states under different assumptions of politically-suitable siting decisions: constrained to districts with high, medium, and low "coal incumbency." Determined by coal job share and other socio-economic factors, this coal incumbency score allows us to compare three scenarios of renewable energy deployment and determine one which most reduces dislocation associated with retiring fossil fuel infrastructure and coal job lay-offs. As a robustness measure, we compare our findings against siting locations constrained to be nearby existing energy facilities, such as coal plants and mines.

Methods

In this paper, we employ our inhouse python package geodata to examine whether different assumptions of politically-suitable siting decisions affect wind and solar capacity factors, energy potentials, and the LCOE of Indian states. We examine district level data sets for coal jobs, coal pensioners, corporate spending on coal, and district mineral funding collected by Pai (2021) to determine a coal incumbency score for Indian districts, categorizing them as high, medium and low coal incumbency. We filter out unsuitable areas from Google Earth Engine's MODIS land-use data following methods set by Lu et al (2020) and separately combine it with high, medium, and low coal incumbency district shapes. Unsuitable areas include forests, water bodies, urban and developed areas, wetlands, natural vegetation, and snow and ice environments. Agricultural land was excluded from the binary mask for solar but not for wind following methods set by Deshmukh et al (2019). We apply this fine-resolution mask onto CDS ERA5 wind and solar reanalysis weather profiles, and extract masked datasets for Indian states. We convert wind speed and solar irradiance to annually averaged capacity factors for the Siemens 3.6MW wind turbine and the KANEKA solar panel. These masked datasets were used to plot capacity supply curves alongside state capacities modeled by Spencer et al (2020) for the years 2030 and 2050. To determine the LCOE for Indian states, distances to nearest transmission line substations were calculated using QGIS. Using the same masking methodology, LCOE supply curves were plotted for different coal incumbency scenarios. As a robustness measure, the same process was repeated for locations constrained nearby existing coal plants and mines.

Results

Our early results suggest that different assumptions of politically-suitable siting decisions drastically impact wind and solar capacity factors, energy potentials, and the LCOE of Indian states. We focus on evidence from states having high and low coal incumbency districts that differ in their shares of coal jobs, pensioners, etc. We find evidence of high renewable energy potential in high coal incumbency districts, indicating efficient capacity factors and LCOE. To summarize and contrast our findings across all Indian states for the three different scenarios of high, medium, and low coal incumbency, we developed an interactive visualization dashboard for capacity and LCOE supply curves alongside state targets and statistics for the years 2030 and 2050.

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Energy, Terrorism, and Economic Growth in the Middle East and North Africa

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Abstract

This paper analyzes the relationship between terrorism, renewable energy, fossil energy, GDP per capita, trade, and income inequality for 21 Middle Eastern and North African countries: Algeria, Bahrain, Djibouti, Egypt, Iran, Iraq, Israel, Jordan, Kuwait, Lebanon, Libya, Morocco, Oman, Palestinian Territories, Qatar, Saudi Arabia, Syria, Tunisia, Turkey, United Arab Emirates, and Yemen. Autoregressive Distributed Lags (ARDL), Wald, and Granger testing approaches were utilized to examine the relationships over the period from 1980-2019. The ARDL and Granger causality tests show that international trade appears to be the strongest cause of both renewable energy and terrorism fatalities in the MENA region. Granger casualty tests did not suggest a direct effect of renewables on terrorism, or vice-versa (p-values of 0.065 and 0.055, respectively). In addition to international trade, foreign direct investment is an important determinant of terrorism fatalities. Overall, security does not seem to have been a major roadblock to renewable energy generation in the MENA region, and likewise increased independence from fossil fuel consumption domestically does appear to have stabilized the region. These results are important as policymakers grapple with energy and security policy throughout the Middle East and North Africa.

Methods

To investigate the relationship between energy consumption, terrorism, economic growth, trade, our empirical analysis compares data from the period 1980-2019. Energy consumption is separated into renewable or nuclear energies (RE) and fossil energy (FE) and is measured in quadrillion British Thermal Units (BTUs) generated per year. The RE metric is a summation of geothermal, solar, wind, tides, biomass, and hydroelectricity while the FE metric is a summation of coal, natural gas, petroleum and other liquids. Both the RE and FE data came from the Energy Information Administration (EIA). Terrorism (T) is the number of attacks perpetrated per year and the data are collected from the Global Terrorism Database (GTD). Per capita real Gross Domestic Product (GDP) is measured in real 2010 US dollars. Trade is the sum of exports and imports divided by GDP. Finally, income inequality is measured using the Gini Index and disposable income. GDP, trade, and income inequality data are collected from the World Bank. These data were then converted into natural logarithms.

The econometric modeling methodology includes three stages: unit root tests, granger causality tests, and Autoregressive Distributive Lag tests. The first step, unit root tests, analyzes the integration order of variables for the level and the first difference. If a unit root is present, essentially means that there is no correlation between two values of the dependent variable. Phillip and Perron (1988) unit root tests were utilized, with the null hypothesis being that there is a unit root and the alternate hypothesis being that there is no unit root.

Engle and Granger (1987) provide a framework for investigating the interrelationships between terrorism, renewable energy, fossil energy, trade, economic growth, and inequality. Granger causality is measured in two steps: the first is to estimate the long-term coefficients and the second consists in estimating the coefficients related to the short-run adjustment. The directions of these causalities are

The ARDL framework, originally introduced by Pesaran and Shin (1999) and Pesaran et al. (2001), is used to examine the short and long-run relationship between variables. Traditional methods require the variables that are being analyzed to be of order 1. RE needed to be differenced twice and, therefore, the ARDL approach is appropriate.

The first step of ARDL cointegration consists of determining the optimal number of lags. In this paper, the number of lags is determined by the Akaike information criterion with a maximum number of lags equal to 2. The null hypothesis for the ARDL cointegration tests states that the long-run estimation parameters are jointly insignificant, while the alternate hypothesis states that the estimated parameters of the variables are statistically significant.

Results

Table 1 shows that the impact of renewable energy on fossil energy is positive and significant, a 100% increase in renewable energy leads to a 3287% increase in fossil energy. Trade also has an impact on renewable energy, with a 100% increase in trade leading to a 10.36% decrease in renewable energy.

Terrorism seems to be drastically impacted by trade and FDI. A 100% increase in trade increases terrorism by 238.4% and 100% increase in FDI causes a 65.4% decrease in terrorism. Additionally, terrorism has a positive, but not statistically significant impact on renewable energy. Increasing terrorism by 100% leads to a 59.1% increase in renewable energy with a p-value of 0.060.

Fossil energy is impacted by trade and terrorism. A 100% increase in fossil energy consumption leads to a 13.6% increase in terrorism. Similarly, a 100% increase in fossil energy leads to a 117.3% decrease in trade.

Gini is impacted by renewable energy, terrorism, and, while FE is not statistically significant, it is important. A 100% increase in gini leads to a 33.9% decrease in renewable energy. A 100% in gini increases the terrorism by 11.4% and decreases fossil energy by 113.7%.

GDP is impacted by renewable energy, total attacks, gini, trade, and FDI. A 100% increase in renewable energy increases GDP by 17.5%. A 100% increase in terrorism increases GDP by 2.9%. A 100% increase in gini decreases GDP by 16.1%. A 100% increase in trade increases GDP by 15.3%. A 100% increase in FDI increases GDP by 3.46%.

FDI is impacted by RE, terrorism, Gini, trade, and GDP. A 100% increase in renewable energy increases FDI by 134%. A 100% increase in terrorism increases FDI by 53.2%. A 100% increase in gini decreases FDI by -258.8%. A 100% in GDP decreases FDI by -831%.

Conclusions

From a practicality perspective, the link between renewable and fossil energy makes sense as renewable energy makes up a minute amount of the total energy mix in the countries studied. Renewable and fossil energy seems to be complimentary in the case of the MENA region which is contrary to a study by Apergis and Payne (2010). They found, with a panel of 80 countries, a negative bidirectional causality between renewable and non-renewable energy consumption suggesting substitutability between these two types of energy resources (Apergis and Payne, 2010).

Trade seems to have a positive relationship with terrorism. This makes sense as more economic transfers involve the movement of people and goods, and that these things could be used for terrorist acts. The result opposes that of Li and Schaub (2004) who found that trade has an indirect negative effect on transnational terrorism.

The increase in terrorism as fossil energy increases makes sense in regards to the MENA region as many of the conflicts in the area can be attributed to control of the oil fields (Yergin, 2016). The increase in fossil energy leading to a decrease in trade can be attributed to the fact that fossil fuels, such as oil, are needed for domestic consumption but also comprise much of the region’s exports. For example, oil and natural gas make up 82% of Iran’s export revenues. When Iran consumes more oil, it has less to export and trade falls.

The link between GDP, renewable energy, terrorism, gini, and FDI is interesting. GDP and energy have long been interconnected, as an increase in energy leads to an increase in production of goods and services that boost the economy. Shahbaz (2013) found a variety of reasons for GDP and terrorism to increase: political instability, poor implementation of economic policies, high regional income inequality, high unemployment, corruption and law & order situation. In particular, if FDI falls economic growth slows and terrorism increases.

FDI is impacted by a wide variety of metrics. The link between FDI and renewable energy seem to follow that of Bildrici (2021) as countries are adapting their energy needs to run on cleaner energy. These countries can attract FDI for high-cost green technology provided that they establish political stability and democratic institutions such as the rule of law and the prevention of corruption.

Economic Models of Photovoltaic Power Generation in Rural Areas of China

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Abstract

Due to the support of government and large investment from solar firms, China has made great achievements in photovoltaic solar energy. However, in rural areas of China where population and land are the majority of the country, the use of energy is still traditional fossil fuels, and the renewable energy industry is still at a very early stage. With the further reduction of the cost of the photovoltaic industry and the implementation of the government's accurate poverty alleviation policies, it has become possible to promote household photovoltaic systems in rural areas of China. At the same time, solar energy as a zero-cost and unlimited resource can lead the photovoltaic system to become an effective economic model to generate extra long-term fixed income for local farmers. Moreover, the participation of the majority of rural households in photovoltaic engineering as a development strategy can also enlarge Chinese photovoltaic industry market, which will help stabilize the whole new energy industry, expand rural employment, reduce urban-rural income gaps and digest the stock of domestic photovoltaic productions which caused by EU and US trade ban of solar products. This paper establishes an economic model for the profit analysis of promoting roof-top photovoltaic systems in rural areas of China, and use panel data modeling approach, namely the fixed effect model, to explore the impact of policy factors (e.g., subsidy) to photovoltaic solar energy’s market share and discusses the possibility to enlarge solar energy industry without subsidy.

Methods

Economic Modeling: We have established an economic model of the rooftop photovoltaic power generation system to measure the return on investment of the entire system. In order to make the model more accurate, we have taken into account all variables that may cause changes in returns. In terms of natural resources, we use the solar intensity and geographic location changes as variables to calculate the power generation potential of different regions. In our opinion, this model is very likely to be the result of quantitative changes leading to qualitative changes. Therefore, population and roof area will become important factors in increasing total income. Therefore, we calculate the proportion of roofs occupied by rural individuals as potential capacity. From the perspective of photovoltaic equipment, we take the ratio of photovoltaic equipment cost reduction, the power generation efficiency of different equipment and the different materials used as cost variables. At the same time, we also consider the labor maintenance cost and the depreciation rate of photovoltaic equipment in our cost model. Combined with the current global photovoltaic power generation policy, we have divided into two small income methods under the large total income model. One is to sell the power generation, and the other is to consume the electricity as a household, and then sell the electricity surplus. We also combine government subsidies, the price of electricity purchased in different regions and the amount of electricity generated to calculate the total revenue and total cost, and finally obtain the overall equipment yield rate. After the return on investment model, we use all the variables in the model and combine the current Chinese photovoltaic data to predict the feasibility of photovoltaic equipment development in rural China in the next ten years and the return on investment for rural individuals. We also established an incremental photovoltaic investment method for rural individuals. By increasing investment year by year to reduce the pressure of total investment to make the project more feasible and we also use 10 years forecast calculation to prove this method.

Econometrics: The fixed effect model uses data collected from the National Energy Administration and China Electricity Council in a time span of 10 years, from 2010 to 2020. The data include the changes of the policy factors over the time span, which will be used as the explanatory variables, ranging between regions, and the corresponding share of photovoltaic solar energy to the total energy usage for each region.

Results

- According to the modeling and calculation results, as the area where photovoltaic systems are installed increases, power generation also increases proportionally, but due to the decreasing trend of photovoltaic costs, the annual increase in investment also decreases proportionally.
- Starting from the third year, the income of the current year exceeds the investment required for the year, which means that the farmers can get cash back from the third year, and it also means that the farmers can install photovoltaic systems without spending money from the third year.
- By the fourth year, the total revenue of the photovoltaic system is higher than the total investment, achieving a 100% cost recovery and a surplus. After the fourth year, the investment return rate for the year is still rising, and the income continues to rise.
- According to the calculation results, it is very reasonable for a single rural household in this area to install photovoltaic systems by 5 square meters each year. This is mainly reflected in the low initial investment, high first-year rate of return, and short time to achieve full balance of expenditures, which can greatly stimulate farmers' enthusiasm for investment.
- From the perspective of national policy, through calculations, it can be found that the investment in the first three years take up more than a half accounted for the total investment in ten years so different electricity price can be designed or subsidies can be increased for the first three years to speed up farmers' balance of payments and people's enthusiasm for investment in the farmers' balance of payments and people's enthusiasm for investment in the first three years.

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Energy & environmental issues

The Energy Transition and Shifts in Fossil Fuel Use: The Study of International Energy Trade and Energy Security Dynamics

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Abstract

The global energy mix is undergoing an accelerating transformation driven by new resources, novel technologies, and climate change-related commitments. Changes in the use and availability of energy resources have affected fossil fuels (coal, oil, and natural gas) trade patterns. Some economies enjoy increasing energy independence, whereas others become more dependent on imports to satisfy their energy needs. Using 2000-2018 United Nations Commodity Trade and International Energy Agency energy- and monetary-flow data, we examine the evolution of the international network of energy flows to reveal new patterns and understand their energy security implications.

The fast-growing body of literature focuses on the energy transition and energy trade dynamics, addressing an extensive list of relevant questions. The key findings and several drawbacks in the existing studies, however, call for further analysis. First, the revealed structural shifts and non-linear dynamics in the trade and security of supply measures suggest that the analysis should be regularly updated to provide valuable insights and development directions. Second, the majority of complex network models, employed in the trade evolution studies, rely solely on the energy flow data neglecting the monetary flows. As a result, the insights about economic implications and rationale are limited, raising the question of trade volumes and trade value linkages. Third, with a few exceptions, the existing research is focused on a single fuel, e.g., natural gas, coal, or oil, whereas the energy transition context and inter-fuel substitution models imply that the trade of the fossil fuels is interconnected and hence, the primary energy sources shall be combined.

Our work explores how the growth in the U.S. unconventional resources, European Union renewable energy, China's natural gas consumption, and changes in other country energy flows affect economies positions and trade-network connectivity. Testing the small-world property helps us understand the diffusion of new technologies, including energy-demand electrification and renewable energy adoption. A modified energy-security index is introduced to highlight the interplay between fuel type and trade partner diversification and domestic supply and consumption balance. The results provide insights into the energy transition and its effect on the international network of energy flows and energy security.

Methods

We have studied the evolution of the international network of energy flows (INEF) for coal, natural gas, oil, individually and in aggregation, for a period of 2000-2018. A set of directed weighted networks for every fuel kind and for every year has been constructed based on United Nations Commodity Trade database. The following characteristics have been used to describe and analyze the networks: the distributions of node degrees and strengths, and the small-world quotient.

Focusing on the trade evolution effect on all the trade participants, we have developed and applied the energy security index to evaluate the effect of the transition on the energy importers and exporters separately. We have compared Hirschman-Herfindahl Index (HHI), energy security index employed by International Energy Agency (ESI), and our own production security index (PSI) and consumption security index (CSI). PSI is based on the share of the traded fuel in the total production, while CSI is based on the share of individual fuel trade flow in the total consumption

Results

We provide insights about the evolution of individual fuel and altogether fossil energy trade, paying particular attention to the changes associated with the production and consumption energy mix changes accompanying the energy transition and adoption of new technologies. Based on the analysis of INEF, the following results were observed:

- Total volume of both: energy and monetary flows have grown over the considered period by almost 50% and 300% respectively.
- Total number of nodes in INEF was growing, driven by growth in the natural gas trade.
- Even though the number of nodes for coal remained fairly stable, the percent of links responsible for the 95% of flows dramatically decreased, suggesting the market concentration related to the changes in China's and India's consumption.
- Small-worldness for fossil fuels network is decreasing over the considered time. This decrease is primarily driven by the developments in the coal trade.
- LNG trade has turned the natural gas trading network into a small-world network with an increasing number of destinations and links.

For energy security issues, the following conclusions may be made:

- CSI has a longer distribution tail and features of a log-normal distribution. It implies that a larger number of consumers have supply-related concerns. In contrast, the smaller number of net exporters tend to be reasonably well secured with much lower exposure to supply risk. That suggests other than environmental reasons for the energy transition by the net energy importers.
- We confirm that HHI has low sensitivity to the ongoing developments associated with the energy transition and changes in energy use.
- On the example of China, we have shown that ESI may move in the opposite direction with CSI if a country is in the energy transition phase.

Looking into the U.S. security and energy trade dynamics, we must analyze its importer and exporter positions in parallel, since the net import of energy was steadily decreasing together with the growth of energy export, starting from 2005. Those developments are reflected in CSI and PSI. The increase in imports in the early 2000s is captured by the increasing aggregate and individual fuel CSI. At that time, PSI has been negligible. The rise in energy-sufficiency has dropped CSI, whereas PSI has been slowly growing, reflecting the export developments.

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An innovative Method for Water Resources Carrying Capacity Evaluation : A Case Study of Qingjiang River Basin

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Abstract

The protection of water resources ecological environment is one of the most important task in watershed in China. The evaluation of water resources carrying capacity (WRCC) is the foundation of suitability of territorial space development. It is necessary to further analyze the weaknesses of coordinated development of various dimensions of WRCC and explore the basis of territorial space development and optimization. This paper considers 中国特有的政策任务， namely, "three water management together ", the types of development priority zones, "red lines" control, and national spatial suitability evaluation, to construct the evaluation index system of WRCC. Monomial evaluation, integrated evaluation and coupling coordination analysis method are used separately to evaluate the

carrying index, comprehensive carrying index and coupling coordination degree of WRCC in Qingjiang River Basin.The results show that :(1) as far as monomial evaluation is concerned, water resources supply is often overloaded on the overall economy, industrial and agricultural development;(2)the comprehensive index of WRCC of the counties in the southwest is obviously better than that of the counties in the northeast;(3) the degree of coupling coordination of water resources carrying in the Qingjiang River basin is not high, which is basically in the primary coordination or barely coordination;(4) the short board of water resources in the Qingjiang River basin presents obvious spatial characteristics, which from west to east are respectively water environment, water resources and water ecology lagging. This paper measures WRCC for industry, agriculture, life and ecology, which is helpful to promote the suitability evaluation of land space development. Meanwhile, the case study of Qingjiang River Basin provides reference for other regions to implement the "double evaluation".

Methods

The data in this paper mainly comes from the public data such as Enshi Tujia and Miao Autonomous Prefecture, Yichang Water Resources Bulletin, Economic and Social Development Bulletin and China Urban Statistical Yearbook in 2018, and some data come from the investigation of Enshi Tujia and Miao Autonomous Prefecture, Yichang Ecological Environment Bureau and Water Resources and Lakes Bureau. Part of the quota standard data refer to GB50137-2011 for urban land classification and planning and construction land, Hubei Water Resources Bulletin, etc. In Table 1 for the reference value and source of "red line".

Results

(1) Carrying capacity of water supply to the overall economy

Only Enshi City and Badong County belong to the bearable area of water resources for the overall economy, while eight counties and cities, including Lichuan City, Jianshi County, Xuanen County, Xianfeng County, Hefeng County, Yidu City, Changyang County and Wufeng County, are overloaded areas, i.e.

(2) Carrying status of water resources for industrial development

Badong County, Yidu City, Changyang County and Wufeng County belong to the bearable area of water resources for industrial development, while five counties and cities, including Enshi City, Lichuan City, Jianshi County, Xuanen County, Xianfeng County and Hefeng County, belong to the overload area of water resources for industrial development, i.e.

Conclusions

(1) In terms of the individual indicators of each dimension, in the water resources dimension, more than half of the areas in the Qingjiang River Basin are in a state of overload, among which Yidu City has the lowest water resources carrying capacity potential and is in an overdraft state, while Lichuan City has the highest water resources carrying potential;
(3) The coordination degree of water resources carrying coupling of ten counties and cities in Qingjiang River Basin is not high, basically in the primary coordination or barely coordination level.

Sustained cost declines in solar PV and battery storage needed to eliminate coal generation in India

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Abstract

Unabated coal power in India must be phased out by mid-century to achieve global climate targets under the Paris Agreement. Here we estimate the costs of hybrid power plants - lithium-ion battery storage with wind and solar PV - to replace coal generation. We design least cost mixes of these technologies to supply baseload and load-following generation profiles in three Indian states - Karnataka, Gujarat, and Tamil Nadu. Our analysis shows that availability of low cost capital, solar PV installation costs of <$300/kW, and battery storage capacity costs of <$75/kWh will be required to phase out existing coal power plants. Phaseout by 2040 requires a 5% annual decline in the cost of hybrid systems over the next two decades. Solar PV is more suited to pairing with short duration storage than wind power. Our results describe the challenging technological and policy advances needed to achieve the goals of the Paris Agreement.

Methods

We draw on multiple years of wind and solar energy data for three Indian states - Karnataka, Tamil Nadu and Rajasthan - to model least cost mixes of wind, solar and lithium-ion batteries that can replace coal generation. Our model is a Mixed-Integer Non-linear Programming (MINLP) optimization problem. In each hour, the hybrid power plant must meet the target coal output profile, subject to operating constraints for the battery and subject to renewable energy production profiles.

Results

We estimate the levelized costs of systems that fully replace flexible or baseload generation from coal power plants are currently in the range of Rs 7-10/kWh, assuming a lower cost of capital. These translate to an abatement cost of between $100-150/tCO2. To be competitive with currently operating coal power plants, installation costs of solar PV and capacity costs of battery storage must fall by at least 60%. An annual cost decline of 5% in both technologies could enable phase out coal power by 2040 in India, consistent with the power sector decarbonization goals necessary to limit global average temperature rise to 1.5 degrees C. This pace of cost decline can also avoid the construction of new coal power plants beginning 2030.

Using Robust Optimization Techniques to Inform US Climate Policy

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Abstract

US energy system development consistent with the Paris Agreement will depend in part on realized fuel prices and technology costs in the future. Energy system optimization models (ESOMs) represent a critical tool to examine future energy system development under different assumptions. While many approaches exist to examine future sensitivity and uncertainty in such models, most assume that uncertainty is resolved prior to the model run. This work focuses on extending and applying robust optimization methods to an open-source ESOM called 'Temoa,' to derive insights about low carbon pathways in the United States. The robust technology deployment strategy entails more diversified technology mixes across all of the energy sectors modeled.

Methods

We apply Robust Optimization (RO) to develop insights about robust future technology pathways that achieve an emissions target consistent with the nationally determined contribution under the Paris Agreement and the Mid-Century Strategy (MCS) released under the Obama Administration. The RO formulation is implemented in an open source ESOM called Tools for Energy Model Optimization and Analysis (Temoa), in conjunction with a US input dataset to explore robust technology development pathways that result in deep decarbonization. This word also makes several methodological contributions. First, we introduce a systematic methodology to form the RO uncertainty set. Second, we provide a methodology to account for the autocorrelation in Temoa's input cost parameters. For example, the range in solar PV capital cost in a given time period will be correlated with the cost in the previous time period. This correlated RO methodology (CR-ESOM) is applied to an ESOM for the first time. Third, this work is the first application of the RO methodology to a large scale representation of US energy system. The RO formulation presented here is generalized for ESOMs, and can be applied to similar models and data sets.

Results

The results indicate that pursuing a robust strategy can save money relative to pursuing a naive strategy that ignores future uncertainty. The degree of realized cost savings from the robust strategy depends on how uncertainty is resolved in the real world. Our analysis indicates that more than 7% of the input parameters assuming their worst-case value has a negligible probability. At such a budget of uncertainty, the robust pathway entails diversifying fuel supply and demand devices. US climate policy should focus on diversifying fuel and technology pathways across the energy system to make it more robust to future uncertainty. At the same time, the future climate is likely to include a carbon price or cap as a central feature, other elements such as regulatory reform, research and development, job training, and social justice and equity present the opportunity to incentivize a more diverse energy system.

Heeding the Call: Office and Retail Building Operator Preferences regarding Load Flexibility

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Abstract

Load flexibility has traditionally addressed the challenges posed to the nation's electrical grid by excessively high peak demand, for example, on a hot summer afternoon when many air conditioners are turned on at roughly the same time. Today, load flexibility is expected to support the grid in the face of challenges posed, in particular, by the need to transition to a more sustainable world while maintaining reasonable electricity costs.

One barrier to commercial electricity customer uptake of programs like demand response (DR), which encourage load flexibility, is the perceived unwillingness of building operators to act when called on to reduce electricity consumption. The purpose of this project is to learn about the tradeoffs commercial building operators confront with respect to building conditions under load flexibility. The paper reports the results of discrete choice experiments delivered through an online survey of office building and standalone retail building operators. Coefficient estimates from stated preferences inform the development of an open-source decision tool for commercial building operators (FlexAssist) designed to facilitate broader and more effective DR participation.

Note that this presentation is part of a group of presentations for a dedicated concurrent session on demand response. The other papers are "Willingness to Participate in Demand Response in the US Midwest: A Market with Great Potential?" and "Changes in Hourly Electricity Consumption under COVID-Mandates: A Glance to Future Hourly Power Consumption Pattern with Remote Work."

Methods

The survey reported on in the paper was informed by extensive interviews with 14 industry experts from a range of organizations including aggregators, consultants, large office and retail energy customer participants in DR programs, and others.

The survey has five main sections: (1) occupation questions, including the personal DR experience of operators; (2) building attribute questions for a building the operator knows well, including any DR program characteristics; (3) details on the equipment and energy bills of the well-known building; (4) two discrete choice experiments (DCEs); and (5) an open-ended question requesting any final thoughts for the project.

The first of the two DCEs presents a current scenario on a hot July afternoon, while the second presents a scenario ten years in the future, when the building is more controllable and has electric heat. For the future scenario, half the sample confronts a hot July afternoon and the other half a cold January day, either from 6-9 am for office buildings or 5-8 pm for retail buildings; this reflects the bimodal distribution of peak electricity use on winter days, but is purposely allocated to the different building types to create harder respondent tradeoffs. In each DCE, the prompt is for respondents to choose eight times between two alternative sets of building conditions if their organization is offered varying amounts of money to reduce energy demand during a DR event. In the current scenario DCE, respondents choose between alternatives comprised of four attributes – economic benefit, reduction in artificial lighting, pre-cooling of the building before the event, and increased temperature during the event. In the future scenario DCE, the alternatives comprise these four attributes plus two additional ones: reduced airflow from the building ventilation system and reduced plug-loads.

Results

Results show that respondents are most sensitive to, in order: (1) during-event temperature change (disfavor); (2) economic benefit (favor); (3) pre-cooling (favor) and (4) artificial lighting reductions (disfavor). Interaction effects are significant. Most importantly, building daylighting matters considerably for preferences respecting artificial lighting reduction. Respondents are also less sensitive to economic benefit if the building they control is large, and they particularly value pre-cooling if during-event temperature change is >2 degrees. Although analysis is not yet complete, there are indications that operator preferences differ between the office and retail building contexts.

The Economics of Natural Gas Flaring and Methane Emissions in U.S. Shale: An Agenda for Research and Policy

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Mark Agerton

Abstract

Natural gas flaring and methane emissions (F&M) are closely intertwined environmental policy issues for U.S. shale oil and gas (O&G) operations. In this paper, we lay out an agenda for researchers and policymakers. We describe why F&M are closely related, both physically and in terms of policy. We perform an interdisciplinary literature review on measurement of F&M. We marshal granular industry data to identify constraints in the natural gas system correlated with upstream F&M. Motivated by this descriptive analysis, we discuss the economic reasons for F&M and the market distortions that could exacerbate it. We then discuss the external cost; we calculate that reported 2015 and 2019 flaring and venting imposed climate costs of $0.9–1.8 billion and $1.7–3.4 billion. We calculate that climate costs of 2015 upstream U.S. methane emissions estimated by Alvarez et al. (2018) were $16.8 billion. Finally, we discuss both existing policy and economic insights relevant to future policy.

Methods

This is a review paper targeted to both researchers and policy makers. We focus on several subtopics in the paper.

1. We survey the scientific literature on measuring methane emissions and flaring. We describe available measurement technology and data that would be suitable for regulation or economic research, and we summarize what is known about the distribution of methane emissions. We

then describe the policy implications of both the distribution of emissions and measurement technologies.
2. We assemble data from several public and private sources on the Texas Permian Basin and North Dakota's Bakken shale. We generate descriptive statistics and graphs that provide suggestive evidence that flaring is caused by intermittent congestion throughout the midstream value chain.
3. We analyze how production characteristics and market structure generate economic incentives to flare. We pay particular attention to the potential for market power and contracting frictions to generate excess flaring, and emphasize the way in which these market inefficiencies could be exacerbated by flaring.
4. We summarize the local and global external costs of flaring and methane emissions. We take off-the-shelf estimates from the scientific literature and US government policy to calculate the climate costs associated with US upstream flaring and methane emissions. We use engineering methods to calculate climate costs of flaring methane as well as associated gas into units that can be compared to market prices.
5. We summarize existing flaring and methane policy in Texas, North Dakota, and at the US Federal level. We discuss ways in which standard market-based policies could be applied to flaring. Because methane is difficult to measure, we spend much of this section summarizing how ideas from the non-point-source pollution literature could be implemented to reduce methane emissions.

Results

The paper has many useful insights for industry, policy, and research. However, there are a few points we think are worth emphasizing in a presentation.

1. Quantifying methane emissions: measuring methane is challenging, but critical for regulation. Emissions happen at many different scales and require a portfolio of technologies to measure well.
2. Well level flaring is intermittent, and many wells both flare and sell gas in the same month. Constraints and congestion arising throughout the entire midstream value chain—gathering, processing, and transmission—and all lead to flaring.
3. Market structure and inefficiencies in gathering and processing can lead to sub-optimal investment in the pipelines and plants needed to reduce flaring. These market distortions could interact with flaring and methane policy in unhelpful ways.
4. Climate costs from upstream US methane emissions are roughly tenfold the climate costs of upstream methane emissions. However, flaring is itself a meaningful source of methane emissions. Flaring and methane emissions can also have localized health impacts.
5. Current policy Texas and North Dakota policy does little to incentivize flaring and methane abatement. Standard market-based instruments may help for flaring, and current satellite-based technology could provide a check on flaring self-reports. However, methane emissions need alternative policies that account for issues in measurement.

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Air quality gains and employment losses from decreasing coal-sourced power production in the United States

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Abstract

While the U.S. continues to rely on fossil fuels for electricity production, coal-sourced power has decreased substantially over the past decade as part of a shift towards a less-polluting energy economy. This movement has led to benefits, as the reduction in coal-sourced emissions yields gains for public health and the environment. But it has also led to costs, as declining plant activity and demand for coal results in losses for displaced workers. Understanding how these outcomes compare to one another, as well as who has won and who has lost, is crucial for policy makers as they work to ensure a just transition while continuing to clean the power sector. Our research evaluates the environmental gains and the employment losses from the declining use of coal-fired power plants in the U.S. from 2014 to 2017. We use quantitative methods to monetize air quality benefits and labor market costs in an effort to compare them dollar-to-dollar. We first use the AP3 integrated assessment model and a social cost of carbon to estimate avoided damages of SO_2, NO_x, primary $PM_{2.5}$, and CO_2 emissions from the coal fleet in 2017 compared to a 2014 counterfactual. We then use panel data regression modeling and present value of expected future earnings calculations to approximate lost jobs and career compensation in the utility and mining sectors from 2014 to 2017 associated with variables that characterize declining coal plant activity.

We find that the public health benefits from reduced coal-sourced air pollution were $88 billion (from $160 billion to $72 billion), associated with 9,500 lives saved. GHG-induced climate impacts fell by $9 billion (from $69 billion to $60 billion). Observable coal-based employment losses were 5,600 in the utility sector and 13,000 in the mining sector. The expected future value of these jobs was $9 billion and $18 billion, respectively. Therefore, air quality benefits outweighed labor market costs by more than 3:1. Spatially, the greatest net benefits accrued in highly populated cities, while the highest net costs were in coal mining counties. Moreover, through a supplemental within-year analysis, we find that 2017 emissions damages from coal outweighed total industry wages by more than 7:1.

There is a clear role for federal public policy to ensure a more equitable transition for coal-dependent employees and communities. The large national net benefits associated with coal's continued removal suggest financial resource reallocation in pursuit of distributional justice has the potential to greatly improve social welfare. It is overwhelmingly beneficial for the U.S. population to move away from coal, but the gains should be recognized and put towards policies helping those most negatively impacted by the energy transition.

Methods

We estimate criteria air pollution emissions damages using the AP3 integrated assessment model [1]. The model first uses atmospheric dispersion and chemistry to link coal plant emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and fine particulate matter less than 2.5 microns in diameter (primary $PM_{2.5}$) to ambient $PM_{2.5}$, which accounts for the majority of air pollution damages in the United States (U.S.) [2]. We evaluate contributions on the margin against an economy-wide baseline, determined using National Emissions Inventory data from the Environmental Protection Agency [3]. Then, AP3 employs peer-reviewed dose-response functions to associate mortality risk with $PM_{2.5}$ exposure [4]. We use county-level age-specific population inventories and associated background mortality rates provided by the Centers for Disease Control and Prevention [5]. Lastly, the model uses the value of a statistical life for mortality risk valuation [6]. We also use the federal government's social cost of carbon to estimate environmental damages from carbon dioxide (CO_2), a greenhouse gas (GHG) [7].

We use regression modeling to explore the associations between coal plants and employment at the county level from 2013 to 2018. Our models account for time-invariant heterogeneity across counties and group-invariant heterogeneity over the years to control for potential omitted variable bias confounding our observed effects [8]. We regress utility sector jobs on coal net generation and coal generator counts, and we regress mining sector jobs on coal quantity sold and mining contracts. We use Bureau of Economic Analysis (BEA) regional data for employment by county and by industry and Energy Information Administration (EIA) sources for power plant operations and fuel data [9]–[11]. We also control for other factors likely influencing employment. We use our regression-derived employment factors (p-value < 0.5) to estimate job losses at coal plants (i.e., jobs/TWh and jobs/generator) and at coal mines (e.g., jobs/short ton of coal and jobs/contract). To monetize employment changes, we calculate the expected present value of the average coal worker's future career financial compensation considering annual wages for plant and mining economic activities, remaining years of work, a real salary growth rate (projected using BEA per capita gross domestic product data), and a discount rate [12]–[14]. Finally, for the supplemental within-year 2017 analysis comparing damages to wages, we extract power generation and fuel extraction coal jobs by state from the U.S. Energy and Employment Report and monetize via annual compensation [12], [15].

Results

We find that premature mortality associated with ambient $PM_{2.5}$ induced by the coal fleet's emissions of SO_2, NO_x, and $PM_{2.5}$ decreased from nearly 17,000 to about 7,300 deaths from 2014 to 2017. The corresponding health damages dropped from \$160 billion to \$72 billion (-55%). Climate damages from CO_2 fell from \$69 billion to \$60 billion (-13%). Total avoided damages from coal's emissions in 2017 as compared to 2014 amounted to \$97 billion. Alternative modeling assumptions result in benefits having been between \$38 billion and \$210 billion.

Our labor market regression models reveal positive, significant associations between jobs and coal plant-related activity. With the utility sector model, we report 8.5 (95% CI 3.4-13) jobs/coal-sourced TWh and 9.5 (95% CI 3.7-15) jobs/coal generator. The mining sector model suggests 45 (95% CI 19-75) jobs/million short ton of coal and 9.9 (95% CI 4.7-17) jobs/contract. Given changes at coal plants from 2014 to 2017, we estimate 5,600 (95% CI 2,200-8,700) jobs lost in the utility sector and 13,000 (95% CI 6,100-22,000) jobs lost in the mining sector. The expected present value of future earnings lost with these jobs was $9.3 billion and $18 billion, respectively, for a total of $27 billion. An uncertainty analysis provides a lower bound of $2.6 billion and an upper bound of $190 billion.

In the base case scenario, total benefits from reduced emissions outweighed employment losses by 3.6:1, and the ratio was 3.3:1 considering only health benefits experienced locally. A critical consideration, however, is where these costs and benefits were experienced. Avoided deaths manifested primarily throughout the eastern U.S. The most substantial gains were in highly populated urban centers. Utility sector costs were experienced where coal plants retired, converted fuel sources, or otherwise cut production. Nearly 40% of mining sector costs were incurred in just nine counties in Kentucky, Montana, Pennsylvania, Texas, West Virginia, and Wyoming. These coal mining counties were also the nine counties with the greatest net losses – they gained $200 million in air quality health benefits but lost $8.1 billion in future employee income.

A supplemental analysis, comparing total compensation to damages in 2017, suggests $17 billion in annual compensation for nearly 170,000 coal workers in the U.S. coal industry. Therefore, populations in the U.S. incurred $4.1 in health damages for every $1 in wages earned by a coal worker. This ratio increases to more than 7.6:1 when including climate impacts. We find that only six states saw income greater than the health damages suffered by their populations in 2017, five being in the less coal-polluted western U.S. Most states, however, had a ratio greater than 1:1. Illinois, Indiana, Ohio, Pennsylvania, and Texas were all within the top ten states for total earnings from the coal industry but also for damages suffered. Together these states generated $5.6 billion in wages, but their populations incurred $25 billion in health damages.

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Leveraging industry as energy storage for a decarbonized grid

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Abstract

Achieving a net-zero emissions economy will require substantial changes to our electricity systems and to the ways that we manufacture the raw materials that become the products we use every day. These zero-carbon electricity systems will also require new, low-cost energy storage solutions to manage both daily and seasonal variability of renewable electricity resources. At the same time, we must also take steps to decarbonize resource-intensive industrial processes. While batteries are well-positioned to provide intra-daily load shifting, and intermediate fuel storage in the form of hydrogen or ammonia is possible, we have not fully investigated the role that industrial commodities can play in a decarbonized energy system. Although industrial output in the US has continued to grow, we see that capacity utilization of manufacturing facilities has remained at approximately 75% since the 1970s, indicating that there is some flexibility within the system to accommodate seasonal trends in electricity production. Here we examine the emissions benefits of converting a metal refining process to use renewable sources of electricity, and the costs associated with using the produced materials as a source for infrequent, but extreme demands for stored energy. Beyond capital costs, the analysis also considers factors like changes in labor demand necessary for manufacturing processes to adapt to renewable sources of electricity, and serve as backup reserves of stored energy, and the policy challenges of implementing embodied energy storage systems.

Methods

We implement a two-stage optimization model to construct and dispatch electricity generation resources in parallel with a zinc refinery. Zinc was chosen as a case study because it is the third most common metal product behind steel and aluminium, and because zinc oxidation, which can be induced using acid solutions, will also produce hydrogen that could be used to power a fuel cell. The case study uses a simplified Texas electricity grid, with increasing renewable electricity requirements. Our objective functions include capital costs and fixed operation and maintenance expenses (for the construction decision) and variable operating costs, including labor costs associated with operating the zinc facility outside of normal business hours to accommodate changes to electricity availability (for the dispatch decision).

Results

We find that in scenarios without stringent zero-carbon electricity requirements, the grid system uses combinations of battery energy storage, curtailment, and natural gas generation to meet electricity demand. In scenarios with high zero-carbon electricity requirements, we found that some zinc storage was selected over hydrogen storage.

Energy efficiency

Seed for Progress

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Abstract

Nitrogen-fixing organisms are usually associated with bacteria and fungi colonies, which are generally located in nodules of Fabales roots. Frankia spp. allow soil degradation and in turn develop a plant-microorganism association.

This mutualism development has a great capacity as a biological control agent, since it can regulate and prevent pathogens. Actinomycetes can contribute greatly to supplant fungicides and can improve crop yield. For the field phase, roots of Coriaria microphylla were collected by scraping nodules on the roots. This medium was heated for 1 minute and Murashige and Skoog medium (MS) 1% was dissolved in this medium, this result was placed in previously sanitized Petri dishes. The plants were placed in cotton and water with diluted MS medium was placed after 4 days.

As results, in the first control phase: from week 1 to week 5 of registration, there was a stagnation in the development of the outbreak. However, increased leaf size and phototropism was noted in plants inoculated with Frankia spp., this is due to a possible immune response from phytocytokines. In the generation of nodular primordium, it was observed that the development of hairy roots from the inoculated area has the same response than specialized agar cultures such as Hoagland medium, that's a signal of plasticity. In plants without actinomycetes, galls were presented, this is due to the following factors: Immunological deficiency and pattern of susceptibility to parasitic infections, and stimulation of cytokines, and resistance to biotic or abiotic stress are seen in arbuscular mycorrhizae.

Methods

Materials and methods:

Field Phase

For the field phase *coriaria microphylla*roots were collected, later According to the methodology of Dávila Medina *et al.,*(2013) the fungi were collected by means of scraping of nodules in the roots.

Laboratory phase

In the same way after the collection, the sample was washed 3 times with 70% ethyl alcohol and to avoid contamination of the samples they were heated with the handle on the lighter. Likewise, according to Billault-Penneteau *et al.,* (2021) *Phaseolis vulgaris* seeds bred under germinator were used. Then agar with a phosphate medium was used. This medium was heated for 1 minute and the agar was dissolved in this medium, this result was placed in previously sanitized petri boxes.

As evidence of the project a timelapse was made, which was done for 1 month, in turn more than 5000 photos were taken. 1 photo was taken per minute from 6 am to 6 pm. The camera was placed on a tripod. Photos were taken with a Sony alpha 7III camera, later Sony's Imaging Edge program was used for the realization of the timelapse. The plants were put in cotton and water with diluted MS medium was placed spending 4 days.

The average temperature at the photo site was 20 degrees Celsius. As part of the Physiological Background: all plants were *phaseolus vulgaris,* the size of the plants was taken at the beginning with imageJ and at the end of the experiment as well. Three plants were inoculated with actinomycetes on the third day of seeing root growth (root bud), while another 3 were not inoculated.

Electrodes installation

After the displacement, two copper cables (cathode and anode) were installed in the organic medium and hydroponic medium to be connected with a set of 10 lights from 60 W lights bulbs (Vural et al. 2012). The Cathode was covered by tarpaulin fibres to isolate the water from cables and the electrodes were installed around the roots and hairy roots around the Frankia nodules.

Data Analysis

Data were obtained in one month of experiment. The data processed correspond to the changes in initial and final size of the stem of *Phaseolus vulgaris* in the presence and absence of actinomycetes with respect to the control and experimental group.

Results

Extraction of C. thymifolia nodules

The fungi were collected by scraping nodules on the roots of ***Coriaria thymifolia***

Conservation of nodules in alcohol at 70%

The sample of nodules with 70% ethyl alcohol was preserved. For the inoculation of actinomycetes a nutritive agar with an M&S medium was used. Germinated and sterilized seeds were transferred to 1% agar-water plates and incubated in the dark at 22 ° C for 3 days. This medium was heated for 1 minute and the agar was dissolved in this medium. Germination trials occurred in the dark as germination rates increased (Bliss 1958). The result was placed in previously sanitized petri dishes .

Colony and root formation

Once the colonies with germinated roots were formed, the roots were inoculated with the Actinomycetes.

After one month, the black coloration of the root is observed as part of the presence of actinomycetes

Nodular primordians

The presence of absorbent hairs was observed from a symbiotic reaction of Actinomycetes (brown color)

Presence and absence of actinomecetes

Excess of roots was observed from symbiotic area in experimental group

(black roots) and the absence of this fungus in the control group.

Stem growth in control and experimental group

Stem growth was observed in the presence of actinomycetes and root growth in areas with mycorrhizae.

Initial and final stem growth in control and experimental group

High stem growth was evidenced when *Phaseolus vulgaris* was in symbiotic interaction with the actinomycete

Energy supply generated by photosynthesis and Nodules nitrogen fixation from Nitrates to Nitrogen ions.

The comparisson was succesful and we could use ANOVA 2 way we could see higher p-values than $\alpha=0.05$ ($p=0.25$) in the hypothesis of the Root Nodules enhance the electroconductivity and electrons release to medium for generate a current that is conducted through cables to Lights in the resistance and turned on 5 lof 10 lights. However, non-treatment plants (NT) we could see a slow effect in the current creation and a lower voltage than Treatment plants (T) (T=120W vs NT=73W). This data were measured by voltmeter.

Conclusions

In the first phase of control: from week 1 to week 5 of registration there was a stagnation in the development of the outbreak. However, vigor was noted in plants inoculated with Actinomycetes, this is due to a possible immune response from phytocytokines in inoculation (Pusztahelyi T., Holb I.J., Pócsi I. 2017). The remarkable plasticity in the generation of colonies in MS agar is uncommon in this type of crops where BAP (Biotin) cultivation is usually required. Likewise, in the generation of nodular primordium, it can be observed that the development of absorbent hairs from the inoculated area has the same response that can be considered as an expression of plasticity and even a character of resistance to the development of competition and selective pressure by not requiring specialized agar cultures such as the Hoagland medium (Zhao, Y., Liu, X., Tong, C. *et al.* 2020). Plants in the Neotropics and even more so with the niche pressures at the microbial and plant level provided by Andean habitats have been able to adapt to favorable conditions for these fungi. In plants without actinomycetes, galls were presented, this should be due to the following factors: Immunological deficiency and pattern of susceptibility to parasitic infections, stimulation of cytokines, resistance to biotic or abiotic stress seen in arbuscular mycorrhizae and, induction to protection from bacterial, fungal or viral infections in mycorrhizal symbioses at the arbuscular level and in survival in the environment (Hao, Z., Xie, W., & Chen, B. 2019). We could see the

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Willingness to Participate in Demand Response in the US Midwest: A Market with Great Potential?

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Abstract

Demand response has great potential to balance renewables by providing ramping and flexibility services to the electricity market. This capacity is increasingly important to electrical grids, as is the integration of more renewable energy. This study assesses the potential demand response resources that utilities can harness from residential customers. We use a contingent valuation method survey to discover residential customers' willingness to accept demand response programs offered by utilities. Data from valid survey responses suggests that 50% of the respondents are willing to enroll in a demand response program. This rate suggests great potential for utilities to harness demand response resources to curb residential peak load in summer, as half of surveyed Midwest residents are willing to participate in one of the programs for a less-than-$50 annual incentive or no incentive. Respondents' participation intention differs significantly when offered no incentive versus a certain level of incentive. When offered a random annual rebate of $10, $20, $30, $40, or $50, on average 47% are willing to participate. However, when the question was asked without mentioning any incentive, 63% of respondents are still willing, which suggests that a low level of incentive decreases willingness to participate. A regression analysis suggests the small token offered by utilities actually decreases the participation intention by about 15%. This result is consistent with the motivation crowding theory. Thus, offering the demand response program without incentives is more efficient at recruiting customers than offering an annual incentive of less than $50. Alternatively, the incentive has to be high enough, probably higher than $50/year, to effectively recruit customers.

Methods

A survey using contingent valuation method was designed to estimate residential customers' willingness to participate in demand response. Three utility direct load control programs were tested – air-conditioner cycling, smart thermostats, and automated real time pricing. Air-conditioner cycling uses switch controls to turn on/off customers' air conditioning units for a short period. Smart thermostats allow utilities to adjust the setting point of customers' thermostats to reduce peak load. Automated real-time pricing is a hypothetical program that allows changing load in response to real-time electricity prices. Respondents were randomly assigned to one of the three DR programs. The survey describes how the program works and solicit participation intention using a binary discrete choice question. Respondents were also randomly assigned to the control group, or a treatment group with incentive provided for enrolling to the DR program. Incentive vehicle is a one-time annual rebate of a randomly assigned value of $$10, $20, $30, $40, or $50.

From July to October 2020, we distributed the survey to a random sample of 3,165 Midwest residents both online and by mail. We received a total of 417 responses (60% online and 40% mail responses), a 13.1% response rate. Data entry and cleaning was done by two people to ensure accuracy and quality. Responses are removed if they are repetitions, using too short time, or from individuals who are not responsible for paying utility bills. A total of 376 valid responses from both online and mail responses are used in multivariate logistic regressions to estimate the willingness to acceptance direct load control programs.

Results

Data suggests that 50% of the respondents are willing to enroll in a demand response program. Overall, respondents show a varied degree of intention to participate for the three types of programs: 54% for air conditioner cycling, 50% for smart thermostats, and 46% for automated real-time pricing. This result indicates that customer participation rate drops when the demand response technology is less mature.

Respondents' participation intention differs significantly when offered no incentive versus a certain level of incentive. When offered a random annual rebate of $10, $20, $30, $40, or $50, on average 47% are willing to participate. However, when the question was asked without mentioning any incentive, 63% of respondents are still willing, which suggests that a low level of incentive decreases willingness to participate. A regression analysis suggests the small token offered by utilities actually decreases the participation intention by about 15%. This result is consistent with the motivation crowding theory.

Energy taxation

Regulation changes and auction performance: Oil and gas leases in Brazil

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Abstract

Governments across the world usually need to balance competing considerations when setting contractual terms for their resource sector. On the one hand, they want to obtain revenues from the resource activities. On the other hand, countries also need to attract investment and associated technology to develop their resource base, so contracts need to offer competitive profits given the risks involved. In this paper, I compare two different auction and contractual designs used for oil and gas leases in Brazil to show how the execution of projects and government revenues was affected by the introduction of a new type of contract for blocks located offshore.

Initially, the government chose a scoring auction for the allocation of oil and gas leases. A scoring auction uses a choice rule (scoring rule) to transform multiple bid dimensions into a single score. Then the firm with the highest score wins the auction. After the auction, winning companies signed contracts under a concession regime, where payments to the government were in the form of royalties, income taxes and special taxes with rates based on production thresholds.

After companies discovered significant reserves of high-quality oil and natural gas in what is now known as the Pre-Salt fields, policymakers saw an opportunity to change the hydrocarbons legislation to introduce a new auction design and a new form of contract for any future auctions in these newly discovered fields. The motivation was to ensure a larger government share in the higher oil and gas revenues expected from these discoveries. The allocation rule changed from a scoring auction to a one-dimensional auction with the sole criterion being the share of profits accruing to the government, but also requiring minimal investments and signature bonus, which were chosen by firms under the scoring auction format. In addition, the new contractual arrangement for the Pre-Salt fields was a Production Sharing Contract. In the process, the government halted auctions until Congress approved the new legislation, which reduced opportunities for firms to keep exploring in the country.

While some authors consider the legal reforms were necessary to allow the government to capture higher rent, others believe the initial contractual and fiscal regime would have delivered similar high rents even in the context of massive discoveries. Moreover, cost recovery mechanisms in both contracts introduce incentives for investment, but the scoring auction format gives more flexibility to firms in their investment commitments and the cash bonus they will pay. This comparison of contracts and auction formats, and its effects on bids and project execution, is not only of interest for oil and gas projects but also for other projects such as those in mining, renewables or infrastructure.

Methods

My methodology integrates a model of optimal development of exploratory blocks into a scoring auction model (see Sant'Anna, 2018 for an application of the scoring auction model to the Brazilian oil and gas case). I use information about discoveries and reserve estimates in the pre-salt area for projects auctioned since 1999. This information allows me to estimate the spatial distribution of reserves, to account for the geological uncertainty firms face. Using data on bid dimensions and forecasts of oil and gas production and prices, several distributions for the operational and investment costs, I estimate the distribution of firms' operational and investment costs.

From these estimated distributions, I simulate the optimal bids and optimal extraction rates under the Concession and Production Sharing regimes. Under different price and geological risk assumptions, the model allows me to simulate government revenues under each regime. Most of existing literature on auctions for oil and gas leases assumes that the value of a block is exogenous. By introducing a stage of exploration and development of a field (following Smith, 2014), I can show how bidding decisions affect the profitability of a project. It also extends the work on contingent payment auctions, applied to the oil and gas case, since it allows the study of extraction adjustments at the intensive margin. In the case of Brazil, the model allows me to simulate the geological uncertainty in the Pre-Salt discoveries, different oil and gas price trajectories, but also the different types of contracts, so I can isolate the effect of contract design from other factors affecting firms' valuation of the block.

Preliminary analysis of the data not only suggests spatial correlation of bids, but also that for bidding rounds made after the large discoveries in pre-salt (Rounds 14-16), cash bonuses are higher than those observed for the PSC blocks in neighboring areas. This suggests that at least from the comparison of bonuses, the concession regime allows for higher revenue collection. However, a more comprehensive comparison requires an estimation of tax collection under each contract, accounting for project execution.

Results

Preliminary results show that on average, after controlling for geological and price uncertainty, the existing concession contracts have an execution rate that is 6.3% higher than that of the production sharing contracts Cost recovery assumptions and the expected level of competition are critical determinants of this, as well as the timing in which development investments are made. Results also show that setting bonus and investment commitments in advance for the PSC auctions reduces available cash flow relative to the scoring auction allocation mechanism, where bidders set the bonus and investment. This leads to lower execution of projects in the PSC case, and lower revenues for the PSC relative to the scoring auction with concession contracts. However, lowering the bonus and investment requirements in the PSC auctions could lead to a different ranking of the two mechanisms in terms of government revenues.

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Market power issues

Determining whether fracking technology has altered market power in the U.S. petroleum industry

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Yousef Nazer

Alan Love

Abstract

This paper measures the potential impact of increasing use of fracking technology on market power exertion in the United States (U.S.) petroleum industry using New Empirical Industrial Organization (NEIO) techniques. Unlike many previous works in the literature, where imperfectly competitive behavior by firms is assumed on one side of the market, our study estimates market power exertion when firms have potential market power on both sides of the market. Using Generalized Methods of Moments estimation applied to equilibrium conditions from profit maximization we jointly estimate market power parameters and technology/supply and demand parameters for both upstream and downstream firms. We find evidence that in the domestic market, both crude oil and refinery firms exerted substantial monopolistic power in U.S. crude oil and petroleum industries. In addition, results indicate that downstream firms exert some monopsony power in the intermediate crude oil market. Moreover, the results show evidence that foreign firms also have a significant degree of monopolistic

power over U.S. import crude oil. However, results indicate that fracking technology has reduced market power in U.S. import crude oil industry but increased market power in the domestic crude industry suggesting a gain in economic rents in U.S. crude oil industry.

Methods

Generalized Methods of Moments estimation applied to equilibrium conditions from profit maximization, and New Empirical Industrial Organization (NEIO) techniques

Results

We find evidence that in the domestic market, both crude oil and refinery firms exerted substantial monopolistic power in U.S. crude oil and petroleum industries. In addition, results indicate that downstream firms exert some monopsony power in the intermediate crude oil market. Moreover, the results show evidence that foreign firms also have a significant degree of monopolistic power over U.S. import crude oil. However, results indicate that fracking technology has reduced market power in U.S. import crude oil industry but increased market power in the domestic crude industry suggesting a gain in economic rents in U.S. crude oil industry.

Do firms use gas markets to raise rivals' electricity costs?

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Abstract

Australia's domestic market for natural gas is deregulated, and daily auctions are used to facilitate wholesale spot trade inside major hubs. These auctions are similar to electricity auctions, except that they are cleared less frequently. Large firms operate in both the gas and electricity markets. When firms submit bids for the day-ahead gas market, the electricity market outcomes are not yet known. It is possible that firms may benefit from strategic bidding in the gas market; since a higher gas price flows through to higher costs for gas-fired electricity and higher electricity prices. I specify an equilibrium model of bidding behavior in the gas market, and use it to empirically analyze bids submitted by the three large firms. Preliminary analysis indicates that a firm's net position in the electricity market is an important determinant of their gas market bids, suggesting that such strategic behavior may be present.

Methods

I model bidding behavior in the natural gas auctions as a linear Bayesian supply function equilibrium. Uncertainty about electricity market outcomes is key to ensuring that a unique equilibrium exists. I follow Bergemann, Heumann and Morris (2021) and Heumann (2021) to solve for equilibrium bids.

Net sales in the spot electricity market are important determinants of the strategic incentives of each firm. I estimate the net position based on observed electricity market bids and estimated generation costs, following Hortacsu and Puller (2008). Net sales by each firm in the spot gas markets are estimated in a separate paper, Neill (2021).

Results

Preliminary results suggest that net spot electricity sales are an important determinant of bidding behavior in the natural gas markets. This suggests that higher expected net sales of spot electricity give firms incentive to raise the electricity price by means of a higher natural gas price. Similarly, expected net purchases of electricity give incentive to lower the gas and electricity price.

The large firms' gas-fired generation and net electricity sales are correlated. This introduces an adverse selection problem in the gas market, similar to the winner's curse, since a high gas price informs bidders that their rivals expect the value of electricity generation to be high.

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Natural gas topics

On the Determinants of Trade in Natural Gas: A Political Economy Approach

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Markos Farag

Abstract

This paper aims to analyze the determinants of trade in natural gas through a political economy lens. Indeed, in addition to the economic determinants of trading in natural gas, the latter could be affected by political determinants such as the economic sanctions and the institutional gap between the trading partners. Moreover, while the literature considers the effect of tariffs, less attention has been attributed to non-tariff measures (NTMs) that might also be imposed for political reasons. To quantify the impact of these different determinants on natural gas trade, we use a gravity model that explains bilateral trade for pipeline natural gas (PNG) and liquefied natural gas (LNG) over the period 2000-2017. In this context, our contribution to the literature is threefold. First, we combine different political factors and quantify their effect on the global trade in natural gas using a comprehensive dataset. Second, from a methodological perspective, we control for zero natural gas trade flows given their importance in the data. These values indeed reflect information on high transportation costs, political-economic factors between the trading partners, and/or domestic market conditions that prevent trading natural gas. Hence, zero trade flows should not be excluded when analyzing the global natural gas market. To do this, we employ the Poisson Pseudo-Maximum Likelihood Estimator (PPML) to estimate our gravity model. Third, we attempt to distinguish between the two commodities in this market, namely PNG and LNG, to see how they are affected by the aforementioned factors. This heterogeneity is accounted for by estimating separate regressions for each commodity. Our results show that economic sanctions have reduced bilateral LNG trade by 24%. We also find that the institutional gap between trading partners exerts a significant negative effect on bilateral PNG and LNG trade, pointing out the fact that institutions

could be considered as fixed export costs in the natural gas market. Moreover, our results indicate that, in addition to tariffs, non-tariff measures have a significant negative effect on trade in natural gas.

Methods

This study combines data from different sources. We use annual data during 2000-2017 for a panel of 54 exporters and 77 importers of natural gas. The main dependent variable is the volume of natural gas trade flows in billion cubic meters (BCM). We use a comprehensive dataset on bilateral PNG and LNG trade flows. We have three variables of interest. The first one is the existence of economic sanctions between the trading partners, and it comes from the newly created database of Kirilakha et al. (2021). The second variable is the institutional quality gap between the trading partners. We rely on the World Governance Indicators (WGI) to measure the quality of institutions (Kaufmann et al., 1999). The third set of variables relates to trade policy, including bilateral import tariffs and non-tariff measures (NTMs) imposed on PNG and LNG imports. We construct the dataset on tariffs and NTMs using the 6-digit harmonized system (H.S. codes: 271121 for PNG and 271111 for LNG). We obtain data on bilateral import tariffs from the World Trade Organization (WTO) [1], whereas we have data on NTMs as ad valorem equivalent (AVE) estimated by Niu et al. (2018). NTMs consist of quantitative restrictions in price control measures, quantity restrictions, and monopolistic measures that natural gas importers can apply.

The methodology used in this paper relies on the gravity model of international trade. This model assumes that bilateral trade volume is directly related to the economic size of the trading partners and inversely related to the geographical distance between them. Yet, to get accurate estimates of the effect of our variables of interest on trade flows of natural gas, we need to extend the basic trade gravity model to control for the domestic market conditions of both exporting and importing countries. Also, we control for the heating/cooling degree days and the renewable energy policies in the importing countries. The heating/cooling degree days is an essential factor in the natural gas market because natural gas prices are affected by extraordinary temperatures.

We implement the empirical analysis in five steps. First, we start with estimating the effect of our main variables of interest on the bilateral natural gas trade. Second, we focus on two alternative measures for the impact of institutional quality, namely the difference in institutional quality and the levels of institutional quality of both the exporter and the importer. Also, we estimate the effect of the six dimensions of the WGI separately on the bilateral natural gas trade. Third, we examine the impact of all types of economic sanctions that are covered by Kirilakha et al. (2021). Fourth, we measure the effect of the interaction between our variables of interest on the natural gas trade. Finally, our empirical analysis reproduces the estimated results obtained in the first step with two different specifications. The first specification measures the domestic market of natural gas differently using the residual demand of natural gas. The second specification, which follows previous studies, uses the OLS estimator instead of the PPML estimator.

Results

For the bilateral LNG trade, we find that economic sanctions could reduce bilateral trade volume in LNG between the sanctioning and sanctioned countries by 24%, on average. The institutional gap between trading partners exerts a significant negative effect on bilateral LNG trade, pointing out the fact that trading partners with similar institutional structures might trade more LNG because this will decrease the associated transaction costs (e.g., Australia's LNG exports to Japan and South Korea vs. Yemen's LNG exports to Japan and South Korea). Moreover, from a trade policy perspective, bilateral tariffs have an adverse effect on bilateral LNG trade. This result is consistent with what happened in the LNG market in 2019. Indeed, in September 2018, China imposed a 10% tariff on US LNG imports, raising it to 25% in June 2019. As a result, US LNG imports to China dropped significantly from 3 BCM in 2018 to 0.4 BCM in 2019 (British Petroleum statistical report, 2020).

For the bilateral PNG trade, our findings indicate that the coefficient of economic sanctions is fairly small and insignificant. This means that economic sanctions do not affect bilateral PNG trade, on average. One explanation could be that high costs are associated with the loss of substantial capital investments in fixed infrastructure with high specificity to transport only natural gas. Moreover, the trading partners' institutional gap has a negative impact on bilateral trade in PNG, leading to an increase in the transaction costs associated with this market. This is in line with the fact that PNG is mainly traded between trading partners with a relatively high gap in their institutional quality (e.g., PNG trade between Libya and Italy; Russia and EU countries; Algeria and Spain; Algeria and Italy; USA and Mexico).

The heterogeneous finding of the effect of economic sanctions on bilateral PNG and LNG trade reinforces the conclusion that LNG is globally traded, reducing the dependence of the trading partners on each other. In contrast, PNG is regionally traded with fixed infrastructure, increasing the interdependence between the trading partners. Also, the effect of the institutional gap is economically smaller on bilateral LNG trade than that on bilateral PNG trade. Our explanation is that most of the suppliers in the PNG market are countries with relatively low levels of institutional quality, making the institutional gap in the PNG market relatively high.

The Economic Consequences of Local Natural Gas Leaks: Evidence from Massachusetts Housing Market

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Xingchi Shen

Abstract

Methane emissions contribute a lot to global warming since methane is 86 times more powerful as a greenhouse gas than is carbon dioxide over a 20-year period (IPCC, 2013). Researchers and policymakers are increasingly focused on methane emissions where primary attention is paid to natural gas production, processing, and transmutation segments. Urban methane emissions from local distribution and end users (gas leaks from pipes) received relatively less attention. In Massachusetts (MA), the leaks from local natural gas pipes account for 10% of the total greenhouse gas emissions (McKain et al., 2015). At the end of 2018, utilities in MA reported more than 16,000 local gas leaks. Although a MA law requires fixing big leaks, the majority is unrepaired. The key obstacle is the high repairing cost. The benefit of requiring the non-hazardous leaks is little known. An optimal environmental policy/regulation depends on the extent to which consumers/citizens value environmental improvements (Greenstone and Jack, 2013; Ito and Zhang, 2020). Estimating the benefits of repairing gas leaks, including avoided greenhouse gas emission, avoided damage to urban greenery, avoided gas explosions risk, and avoided bill loss, is a challenging question with great policy relevance.

This study aims to estimate individuals' Willingness to Pay (WTP) for repairing the gas leaks using a hedonic pricing method based on the housing market in MA. We merge two unique datasets (the Zillow's Real Estate Database and a publicly-available dataset of gas leaks) and develop a Difference in differences (DID) method to estimate the impact of local urban gas leaks on nearby housing value. The surrounding features of a property, including the impact of gas leaks, would be reflected in house prices. Since not every homebuyer can notice the gas leak, our estimated impact can be interpreted as the lower bound of the average population's WTP for repairing the gas leaks.

We find that gas leaks significantly reduce nearby house prices by 2.61% ($11,700) on average in MA. Our estimation is robust to the different boundary definitions of the control group. More importantly, the estimated benefits of fixing gas leaks are larger than the average costs per repair reported by utilities in MA.

Methods

We combined two unique datasets. First, we obtained the utility-reported, state-wide data on gas leaks from two environmental organizations, HEET and Gas Leak Allies. The gas leak dataset in our study records around 80,000 gas leaks reported by seven natural gas utilities in MA from 2014 to 2019. The data provides four important variables: the gas leak's location (full address, latitude, and longitude), leak grade (1, 2, and 3), date discovered, and date repaired. Second, we obtained the Zillow's Assessor and Real Estate Database (ZTRAX) from Zillow group, an online real estate database company. The ZTRAX database records the detailed individual building features via ten independent assessments from 03/22/2016 to 01/02/2020, as well as all the property transaction records since 1900s in MA.

We use the DID method to estimate the impact of nearby gas leaks on house sales prices. Treatment group consists of houses with a nearby gas leak. For each gas leak, we apply a fuzzy matching algorithm based on longitudes and latitudes to find all the residential buildings within a 20-meter radius. In our baseline analysis, the houses closest to the leak enter the treatment group. Houses within 20 meters to 500 meters of the leak are the control group. The treated houses were sold at least once before the occurrence of a gas leak and once within the occurrence of a gas leak. The control houses were also sold at least twice during a similar time window of treated houses. A two-way fixed effects model controlling building age, month-of-year fixed effect, city-year fixed effects is applied to estimate the gas leak's impact on house prices. We also conduct a robustness check by changing the boundary of control group and find that our estimations are insensitive to the change.

Results

Our results suggest that the local gas leaks (including all grades) significantly reduce nearby house prices by 2.61% ($11,700) on average in MA. Grade 2 leaks can significantly reduce the house prices by about 11% on average while grade 3 leaks decrease the house prices by 1.97% with many estimation noises. Grade 2 leaks are potentially hazardous and need to be repaired within one year. Grade 3 leaks are temporarily non-hazardous and not required to be repaired. Since not every homebuyer can notice the gas leak, our estimated impact can be interpreted as the lower bound of the average population's WTP for repairing the gas leaks.

Whether fixing gas leaks is warranted is determined by comparing the costs with the benefits. We conduct a back-of-envelope analysis to estimate the fixing cost. Based on utility-reported data from the federal Pipeline and Hazardous Materials Safety Administration (Morgan et al., 2021), a total of 17,533 unrepaired leaks were reported in MA at the end of 2018, with an estimated cost of repair of $59,260,458. Thus, the average cost per repair is $3,380. Based on our estimations, the repairing benefits are larger than the repairing costs.

Option Value of Becoming Independent: Investment Decisions of Power Generators in South Korea

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Abstract

This paper studies the option value of becoming an independent power generator in South Korea. After natural gas industry was deregulated in 2001, power generators have an option to invest in their own LNG terminals and storage tanks to import liquefied natural gas (LNG) for self-consumption. This option allows them to procure natural gas without relying on the wholesale domestic provider. We argue that there is a sizable option value of becoming an independent power generator. To measure this value, we model power generators' investment decision problem using dynamic discrete choice econometric following the seminal work of Rust (1987). Using the estimates from this model, we simulate counterfactual policy scenarios to analyze the impact of more strict or more loose regulations for LNG import.

Methods

1

Results

2

Conclusions

3

The Mixed Impact of Prorationing: The Results of a Natural Experiment

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Abstract

While prorationing of oil and natural gas wells is often viewed as a pro-efficiency response to a common pool program, there is very little empirical work on its actual effects. We take advantage of a recent natural experiment in Oklahoma to determine the impact of more stringent prorationing rules on natural gas production. Prorationing is shown to have a limited impact on the production of gas by larger companies, less than half the amount that would be implied by the context of the rules. Prorationing does not appear to have any impact on the production of gas by smaller companies. Prorationing in Oklahoma does not serve to address any common pool problems.

Methods

We obtain data on natural gas production by well from the state of Oklahoma. We tested to see the impact of prorationing on production on a well-by-well basis. We are able to test for geological features, company attributes, and the expected natural decline of production from wells.

Results

Prorationing does result in reductions in production, but less than have of the reduction that the law implies. Further, the data indicates that smaller companies are not effected by prorationing rules. This result applies whether the smaller companies are based in Oklahoma or elsewhere.

Quantifying the Role of Midstream Congestion and Market Structure in Permian Flaring

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Abstract

Flaring from oil or natural gas wells occurs when producers burn the natural gas rather than capturing and selling it. In 2019, the U.S. flared over 600 billion cubic feet of natural gas—enough to power 7.9 million households for a year (World Bank 2020). This represented 11.5% of global flaring and was the third-highest total globally.

Flaring gas, while preferable to simply venting it, is a significant, visible source of pollution. Flaring is easily identifiable from low-resolution “night light” maps. Efficient flares release both greenhouse gases and EPA-designated criteria pollutants. Under real world conditions, flares are not fully efficient and can become entirely unlit, venting methane directly into the atmosphere. Recent scientific studies estimate significantly larger methane emissions factors for flaring compared to EPA emissions estimates (Gvakharia et al. 2017; Environmental Defense Fund 2020).

The causes, external costs, and policy solutions for flaring are not well understood, though the topic has become increasingly important as U.S. shale oil and gas production has boomed over the last two decades (Agerton, Gilbert and Upton 2020). While U.S. oil production and flaring have fallen during the pandemic, flaring may rise as oil demand recovers.

In this paper, we investigate the role of constraints in the supply chain of natural gas production on flaring. First, we estimate the causal impact of limited transmission pipeline capacity on flaring. Second, we estimate the short-run relationship between variation in natural gas processing capacity and flaring. Third, we estimate the correlation between changes in gathering line density on local flaring levels.

The relative effect of each of these supply chain factors has significant implications for the understanding of optimal flaring policy. For example, a finding that processing capacity has a larger impact on flaring as compared to transmission capacity would indicate the relative effectiveness of policies which favor expanding processing infrastructure.

Therefore our article makes several contributions, both specific to flaring and more broadly to economists’ understanding of market structures and environmental externalities. We provide new stylized facts about flaring, which highlight questions for environmental economists and policy makers about the implications of market structure for flaring policy. In addition, our article contributes to the broader literature on spatial competition and externalities (Fowlie, Reguant, and Ryan 2016; Lerner and Singer 1937; Salop 1979). Finally, the results of this article are timely and policy relevant by helping to address the important question of how to reduce flaring.

Methods

We construct a novel dataset on shale development activity in West Texas' Permian Basin, the heart of unconventional U.S. oil production. Our data correspond to the 2009 to 2021 time period and contain comprehensive spatial information on upstream well activities, including drilling, extraction, and flaring. Flaring information is based on both self-reported flaring levels from the Texas Railroad Commission and nighttime Visible Infrared Imaging Radiometer Suit (VIIRS) data. Our data also incorporate midstream pipeline networks, including information on pipeline capacity, spatial location, maintenance events, and the midstream operator. Finally, we further supplement our data on downstream processes in the supply chain with information on natural gas processing plant location, throughput, and capacity.

Using this data, we first employ event study and simple regression designs to investigate the role of transmission capacity in the determination of flaring. Specifically, we compare flaring in the Permian on days before or after pipeline capacity is reached. The event study design allows us to distinguish the role of transmission capacity separate from processing capacity and other factors. To examine the possibility of a non-linear relationship between transmission capacity and flaring, we supplement this analysis with a high frequency regression design that separately estimates the impact of different degrees of transmission shortage on flaring. We investigate causal impacts using an IV strategy based on transmission outages.

Similarly, we investigate the impact of natural gas processing capacity through an event study framework. We use an event study design to examine changes in regional flaring following days where a processing plant is subject to an unscheduled shutdown or has scheduled imports in excess of capacity. This allows us to isolate the specific role processing capacity has on flaring separate from gathering lines or pipelines, which historically have increased with processing capacity.

Finally, to examine the potential role of gathering systems on flaring we estimate the correlation between local gathering line density and local well level flaring using a high-density fixed effects regression design. Specifically, we incorporate field by year and operator by year fixed effects along with various distance metrics to isolate the impact of contemporaneous shifts in gathering system availability separate from variation in transmission or processing capacity. We also explore causal impacts using an IV strategy using partial data on pre-shale gathering infrastructure.

Results

First, we highlight stylized facts consistent with market power leading to flaring. For example, the majority of flaring happens at locations which both flare and sell gas in the same month. This indicates the presence of capacity constraints—a hallmark of Cournot competition.

Second, our event study results indicate that on the specific day where scheduled exports exceed transmission capacity, there is a positive and statistically significant increase in flaring. In addition, for days preceding or following events where scheduled exports exceed operational capacity, there is no evidence of excess flaring. These results indicate that lack of transmission capacity explains a significant portion of flaring in the Permian.

Finally, we find that an increase in both gas processing capacity and gathering line density within 25km of a well (measured along the pipeline network) is associated with increased gas prices at the wellhead and decreased flaring. These results motivate discussions on the relative economic efficiency of market-based environmental policies in the flaring context and highlight possible challenges for implementation.

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Are we building too many natural gas pipelines?

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Abstract

Natural gas has been considered as a bridge fuel in the ongoing energy transition because it is cleaner and more efficient than coal. In the market context, along with increases in U.S. natural gas production and demand in electricity generation and industrial sectors in recent decades, new transmission pipelines have been constructed to link the expanded and new production sources to more consumers around the country. These shifts in demand and supply will require gas flows in the U.S. to change significantly, therefore, require infrastructure investments in new gas pipelines and storage. On the regulatory side, to get approval from Federal Energy Regulatory Commission (FERC) to build a new interstate pipeline or expand a pipeline's capacity, a company demonstrates market needs for capacity expansion by showing long-term contracts between pipeline companies and gas shippers for gas transportation. This simplicity of the regulation has greatly encouraged pipeline investments and has contributed to the speed of natural gas infrastructure development after the fracking boom. However, this practice has been criticized where both pipeline companies and shippers are affiliated entities. The reason is the inherent risk-shifting in such transactions, whereby pipeline developers earn a return above risk while captive customers are imposed with substantial reservation costs regardless of whether their gas utility uses the pipeline capacity. In Feb 2021, FERC issued a note of inquiry seeking suggestions on what methodology and types of additional or alternative evidence FERC should examine to determine pipeline project need. This paper aims to contribute to the ongoing regulatory debate by examining the efficiency of the current natural gas pipelines in the contiguous U.S. In addition, the paper provides a model-based project evaluation method that will be useful to assess the need for a new interstate pipeline in the context of ongoing energy transition and decarbonization policies. Taking into account the predicted future demand and supply, the substitution and/or complementation between new pipelines and new storage or between multiple pipeline projects is crucial to examine whether a company should build more pipelines. In this study, we build a linear programming model that objects to

minimize the total cost of natural gas production, pipeline, and storage to meet the predicted U.S. domestic demand. The model determines the need for additional storage and pipeline capacity to accommodate the gas flow between supply and demand regions. By contrasting the optimal outcomes with the observed outcomes and comparing the total cost in each case, we discuss the efficiency of the current natural gas pipeline system.

Methods

This paper focuses on providing a model-based project evaluation method to determine the need for pipeline and storage projects in the context of decarbonization with long-term insight. We illustrate the model by examining the efficiency of pipelines that had been built during the 2002-2018 period given the projections of demand and supply up to 2050. For this purpose, we create an optimization model that minimizes total capital and operational cost to meet demand at each state in the contiguous U.S. For comparison purposes, we keep gas demand, supply, and cross-border imports and exports exogenous at the observed or predicted quantity when we compute the optimal storage and pipeline capacity. We then solve the model to define the necessary additional capacity of storage and pipeline. The model input is daily data at the state level. We obtain the natural gas data, including historical and projected data, mainly from the U.S. Energy Information Administration (EIA). Since EIA data is monthly frequency, we estimate daily demand, supply data using daily weather data from the PRISM climate database. We then select a representative year for every five years and account for every day in the selected year in the model to reflect between day variation of gas supply-demand and interstate movement. Solving the model gives us the optimal additional pipeline and storage capacity built each year. Finally, we contrast optimal outcomes versus observed pipeline and storage capacity to evaluate whether pipeline companies overinvest in historical pipeline projects in 2002-2018 given the decarbonization pathway to 2050.

Results

The preliminary results show that generally, we are building too many pipelines and less storage than necessary. However, this is the case for all contiguous states. Pipelines had been overbuilt in some regions while under-invested in others. Most of the states in gas consumption areas need to build more storage. The total capital cost spent on historical pipeline and storage projects in 2002-2018 was way higher than it should be in the optimal model.

Nuclear power issues

Production costs uncertainties of SMR-concepts - A model-based Monte Carlo analysis

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Abstract

The role of nuclear power in a future low-carbon electricity system is still debated intensively. In this debate, supposedly new reactor technologies are gaining more attention, especially the so-called small modular reactors (SMR) (Chu 2010). SMR concepts are nuclear power plants with relatively low power ratings (e.g., up to 300 MW_{el}, see Pistner and Englert (2017), Pistner et.al. (2021), Mignacca and Locatelli (2020), Boarin et. al. (2021)). They are currently re-emerging in the debate about large scale decarbonization of the energy sector because of the failure of nuclear power plants with higher power output (e.g., 1,000 – 1,600 MW_{el}) to become cost-competitive (Lloyd, Lyons, and Roulstone 2020; Wealer et al. 2021). The value proposition of SMR developers and national energy and defense administrations is that SMR concepts could overcome their disadvantage of size through increased productivity by – among others – mass production, learning, or co-siting (Rothwell 2016; Boarin et al. 2021). In this paper we analyze the competitiveness of SMR concepts by combining investment and production theory with Monte Carlo simulations of uncertain parameters.

Methods

We analyze the costs of SMR concepts deploying publicly available costs and recent cost theory, to evaluate an investment decision with the help of Monte Carlo simulation of economic indicators (Wealer et al. 2021). First, we collected a unique economic dataset for SMR concepts from different manufacturers (Pistner et al. 2021). Following Lloyd et.al. (2020), we computed cost in respect to a possible range of scaling effects between [0.1;0.85] with:

$Cost_{SMR}=(Cost_{LR}* (Size_{SMR}/Size_{LR})^{n})* (1-x)^{d}$ and for the approach of Rothwell (2016) with:

$Cost_{SMR}=(Cost_{LR}* (Size_{SMR}/Size_{LR}))*n^{(\ln(Size(SMR))-\ln(Size(LR)/\ln(2))}*(1-x)$

with LR for values for high capcity reactors (Nuclear power plants > 300 MWe), SMR respresenting values associated with low capacity reactors (nuclear powerplants < 300 MWe), n representing the scaling effects, x representing learning rates. Unit for “costs” is USD/MWe, and “Size” is in MWe. For the calculation of costs we assumed a “best case” learning rate of 10% as described by Mignacca and Locatelli (2020) and asumme d=1, for each doubling of number of units. We identify investment intervals subject to both scaling factors driving cost and learning effects reducing cost. Calculations are based on public available costs of the Vogtle AP1000 nuclear power plant (for the pressurized water reactor type) described by Wealer et.al (2021) and the Superphénix prototype (for the sodium cooled

fast reactor type) described by Butler (1997). As a second step, in order to incorporate uncertainty, we simulate certain economic parameters, namely electricity wholesale market prices, investment costs, load factor, within the previously calculated cost ranges. Lastly, we determine the net present value (NPV) and the leverage cost of electricity by Mont Carlo simulations and evaluate current theory for available manufacturer costs.

Results

Our results for unified distributed investments in SMR concepts with wholesale electricity spot prices for 2020, suggest that the lack of competitiveness attributed to large nuclear reactors with their uncertainties shown by Wealer et. al. (2021), also applies to current SMR concepts. Furthermore, we can assume through recalculation that it would take a quantity of more than 1000 SMR reactors to reach a breakeven with currently in use high-capacity power plants (Figure-1). This is in contrast to a previous, much lower, estimation from Litvag (2014). Figure-2 additionally shows a preliminary best case scenario for one production doubling of SMRs, which is actually a negative NPV (Mignacca and Locatelli (2020), Pannier and Skoda (2014), EEX (2021) , Cooper (2014)).

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Investigation of Small Modular Reactor Power Plants in Cogeneration Applications

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Abstract

Small modular reactors (SMRs) could help society reduce greenhouse gas emissions associated with energy supply, while still providing reliable power. The purpose of this study is to investigate the economic feasibility of using an SMR-based power plant in comparison to a natural gas-based system.

Two technical scenarios were devised for the comparison. In the first scenario, the electrical output of the SMR is used for industrial or commercial purposes (relatively stable demand for power), as well as for hydrogen production. In the second scenario,the electrical output is directed to residential consumers (varying demand throughout the day), while excess power is used for hydrogen production through high-temperature electrolysis. Terrestrial Energy's IMSR 400 is compared against a natural gas power plant with a steam methane reformer for hydrogen production.

A high-level Net Present Value (NPV) analysis is used to estimate the cost per kiloWatt-hour of the two types of power plants in each scenario.

It should be noted that the uncertainty in the SMR cost data, in particular, is high given SMRs' stage of development. However, results of analyses such as these can be of use to SMR developers, as well as to

decision makers in government and industry who may be considering the implementation of SMR technologies.

Methods

Small Modular Reactors (SMRs) could be the future of Canada's nuclear industry and one of the solutions to the country's commitment of achieving net-zero emissions by 2050 [1]. As a low-emitting source of energy with a wide range of applications, SMRs may fill in the niche left behind by the decommissioning of CANDU reactors starting in 2025 [2][3]. While expected to be less capital-intensive than traditional nuclear plants, there is still considerable uncertainty around their eventual economic performance.

In addition to power generation, SMRs are often designed with load following capabilities (e.g., [4][5]). Load following is the ability for a power plant to adjust its power output according to the demand and electricity price fluctuation throughout the day. However, in nuclear power plants, lowering the power output does not significantly reduce operating expenses and may stress the reactor thermo-mechanically. The preferred option is to have the primary circuit at full power and use the excess electricity for cogeneration [6].

The purpose of this study is to investigate the economic feasibility of using an SMR-based power plant in two scenarios, one meeting a fairly steady electrical demand, and the other a load following application, in comparison to a natural gas-based system.

This study comprises two main steps:

1. Establishment of two energy system scenarios for SMR- and natural gas-based power plants. This is achieved through identifying the electricity consumers and their demand, then specifying the producers.
2. Estimation of the costs of the SMR- and natural gas-based systems through a high-level NPV analysis.

General Framework of the Energy System Scenarios

Two scenarios apply to both the SMR- and natural gas-based systems. The first serves industrial and commercial consumers entirely where electricity demand is relatively stable [7]. The second serves residential users whose electricity consumption varies throughout the day [8]. In both cases, "excess" electricity is used to cogenerate hydrogen; the difference is that for the industrial consumers, the excess is at a constant level whereas for residential consumers, the surplus is mainly from periods of low demand. The power generating systems have been scaled to meet the demands of both types of consumers.

The annual average demand by consumer type is determined based on data from the Durham Community Energy Plan Baseline Energy Study of 2015 [7]. Similarly, the IESO [9] provides the trends of hourly energy consumption in Ontario each day, which was applied to model the residential consumers' demand.

Economic Analysis

The NPV analysis is conducted to investigate the economic feasibility of both types of power plants as independent electricity producers. This study uses a top-down approach to estimate the costs of the IMSR-400 and natural gas systems in Durham Region. Informed by the guidelines provided by GIF/EMWG (2007), this method is selected due to the lack of data available for a bottom-up approach [10][11].

Results

The results of this study are based on several simplifying assumptions and commodity prices that can fluctuate significantly (namely natural gas). In addition, the IMSR-400, along with many other Gen IV SMRs, is in the design and development phase, hence there is not a significant amount of publicly available, accurate data for modelling. Consequently, a large uncertainty is expected for this study and the results should be considered preliminary and indicative of relative performances.

Further areas to explore with regards to SMR deployment may include regulatory, environmental, and social aspects of power generation and power plant construction. Another potential prospect is to expand the current model to encompass the fluctuations in natural gas prices.

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OPEC and oil markets

OPEC and the Oil Market

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Abstract

This article evaluates the importance of OPEC on oil price fluctuations, including whether its role and credibility changed over time. Using an event-study and a text-analysis approach, we identify the effects of OPEC announcements on oil price fluctuations. We find that price volatility is relatively higher than usual around OPEC meetings. Also, members' compliance, a proxy for credibility, has strongly fluctuated over time. Using an ordered multinomial logit framework, we identify some of the factors that explain OPEC's decisions to cut, maintain, or boost members' oil production. The model can successfully predict OPEC meeting outcomes 66 percent of the time, based on meetings between 1989 and 2018. The most relevant factor explaining OPEC's decision is the cyclical fluctuation in oil prices suggesting that OPEC's objective is to stabilize the price around its medium-term equilibrium rather than inflate it. Finally, the transparency of OPEC's statements has modestly improved between 2002 and 2019.

Methods

An event-study, an ordered multinomial logit framework and text-analysis approach

Results

our results are built on four main components: an analysis of 101 meeting announcements between 1989 – 2020; OPEC's adjustment mechanism; OPEC's communication with the oil market; and the future of OPEC+. We conclude OPEC still matters. Its role is essential to ensure stability and resilience over short and medium terms. In addition, our framework illustrates 66% of OPEC's meeting decisions relied on IMF core variables as well as other macroeconomic indicators. The most relevant factor is the cyclical fluctuation in oil prices suggesting that OPEC's objective is to stabilize the price around its medium-term equilibrium rather than inflate it.

Petroleum (upstream & downstream)

Effects of the Shale Boom on Self-Employment in the U.S.

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Abstract

This paper exploits new oil and gas activity generated by recent technological advancements to understand the effect of localized boom and busts on self-employment. We find a positive and contemporaneous impact on self-employment in non-mining sectors, mainly stemming from unincorporated self-employed individuals. The impact is short-lived, i.e. once the boom subsides, the self-employment adjusts closer to pre-boom levels. Point estimates suggest that a large part of the employment adjustment comes from unincorporated self-employed individuals - a group that makes up about 6% of total employment.

Methods

We aggregate the value of oil and gas production into commuting zones in the U.S. We then regress self employment at the CZ level on the value of production and lagged value of production. We conduct the same exercise for total employment, and then calculate the share of the employment adjustment that comes from self employed workers.

Results

Current results suggested that unincorporated self employment accounts for approximately 20 percent of the employment adjustment, yet this group only makes up about 6 percent of aggregate employment.

We note, though, that we are currently making several improvements to data construction. Updated results (after significant data improvements) provide results that are empirically more robust, but also impact the point estimates. Specifically, new results (coming soon) suggest that about 10 percent of the employment adjustment comes from unincorporated self employed workers, again a group that makes up just 6 percent of aggregate employment.

USAEE Working Paper can be found here:

https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3656373

Optimization model for crude oil allocation in Nigeria

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Abstract

This paper examines the end use of Nigeria's oil production and proposes a framework within which the produced oil can be optimally deployed to meet the objective of maximizing the total producer and consumer surplus. The imperative of this paper is derived against the backdrop that while the oil industry contributes more than 90% of the foreign exchange revenues to the country, it is not clear that the allocation of more oil to export than domestic utilization is an optimal pathway. The profile of Nigeria's refinery capacity build-up versus oil exports ratio indicates that the most aggressive refining capacity ramp-up occurred between 1979 and 1989. In that decade Nigeria increased her refining capacity from 160kbpd (1979) to 445kbpd (1989), even as the Country's oil exports as a percentage of her production increased rapidly from 76% to 89%. By 2009, 99% of Nigeria's production was dedicated for export at the expense of domestic utilization which plunged to 7% with the consequence that >80% of domestically consumed refined products was imported. Furthermore, a comparison of refinery utilization between Nigeria and OPEC shows that Nigeria refinery utilization declined from 70% (2000) to 0% (2018) while OPEC utilization declined from 95% (2000) to 63% (2018).

Methods

We developed the Reference Energy System which in this case is a transshipment framework of crude oil utilization through a network of possible end-uses. This is then the basis for the development of a mathematical programme for the optimal allocation of crude oil. The objective function is developed which is to maximize net benefits which is the difference between "Inflows" and "Outflows". Our "Inflows" are the sum of receipts from export crude oil sales, refined products and domestic sales of refined products. The "Outflows" are constituted of upstream costs, refining costs, distribution costs and "loss" costs. Constraints are identified as the total domestic refining capacity, offshore refining capacity, upstream oil production, and refined petroleum product demand. Within this framework, we carried out a "Backcast" to determine what historical optimum oil allocation would have been by using metrics such as Oil Export/Production ratio, and Import/Demand Ratio.

Results

The mathematical programme which we developed has twenty-four (24) decision variables in the objective function and forty-four (44) constraints. The decision variables are the (quantity of oil for export), (quantity of oil for offshore refining), (quantity of oil for domestic refining), (quantity of oil imported), as well as quantity of products as follows: (list of product quantities for export), (list of product quantities imported), (list of product quantities supplied to domestic from local refineries), and (list of product quantities swapped from offshore refineries). Our preliminary results indicate that keeping historical refining utilization as-is (to mirror actual refinery performance), the optimum product import/demand ratio ought to have ranged from 70% (2010) to 85% (2014) instead of the actual 82% (2010) to 89% (2014). Additionally, we noted that in the years 2015, and 2016, the optimum import/demand ratio could have resulted in higher product imports than the actual. However, our model suggests that from 2018 to 2020, actual imports have been consistent with the optimized import/demand ratio.

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What Drives Returns on the Corporate Bonds of Oil and Gas Companies?

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Abstract

This paper investigates what drives corporate bond returns for a large cross-section of oil and gas companies. Despite the corporate bond market being an important source of financing for many oil and gas firms, there is a dearth of research on this subject at such a disaggregated level. Prior work in the corporate bond literature has generally focused on aggregate corporate bond indexes, which cover wide segments of the economy. We use micro-level bond price data from the TRACE database to focus specifically on oil and gas companies.

Our work focuses on the ability of three broad sets of variables to explain the returns. The first group are factors previously identified in the finance literature as having predictive ability for returns in the bond market at large. The second are popular measures of global economic activity, such as the shipping index of Kilian (2009). The last set is of energy prices, many of which are tightly connected with earnings and profitability of oil and gas companies.

Methods

Our data comes from the TRACE database, which provides high quality information on transactions in the corporate bond market for all sectors of the U.S. economy starting from 2002. Individual bonds are linked to their issuing company and each company is assigned a six-digit NAICS code by TRACE.

Our analysis focuses on upstream oil and gas companies, which are mainly found in NAICS codes 211 and 213. Upstream oil and gas firms are an ideal subset of the energy sector to study bond returns because they often rely on debt to finance high levels of capital expenditures. We divide the upstream firms into oil majors (such as Exxon and BP) and another group that includes the remaining firms, hereafter simply the upstream group. Our data also let us consider the midstream, downstream, and coal sectors, but those groupings are not the primary focus of this work.

The TRACE database provides monthly return measures for each corporate bond along with a host of information related to the bond itself, such as maturity, coupon rates, and callable status. Our total sample includes almost 60,000 return observations spanning the period from 2002 to 2019.

We pool returns across bonds and firms into the majors and upstream categories. We run panel regressions where we include different explanatory variables to determine which have the best explanatory power for bond returns. The explanatory variables include financial factors, global activity indicators, and commodity prices. The financial indicators are market returns and downside, credit, and liquidity risk from Bai, Bali, and Wen (2021). The global activity indicators include world industrial production, global steel production, the Kilian index of international shipping costs, a real commodity price factor, and the global economic conditions indicator of Baumeister, Korobilis and Lee (2020). The commodity price variables are the change in West Texas Intermediate crude, Brent crude, Henry Hub natural gas prices, and the price of coal.

Results

Broadly speaking, we find the results are quite different between the upstream group and the majors. The market factor, and to a lesser extent, the liquidity risk factor best explain the variation in bond returns for the majors. The other financial factors, the global activity indexes, and commodity prices add little explanatory value. Interestingly, the coefficient on the liquidity risk factor points to the bonds of the majors as being "safe-haven" bonds in a particular sense: their returns tend to rise when liquidity concerns rise in the market. About 34 percent of the variation in the returns of this group are explained by the market and liquidity risk factors.

On the other hand, we find bond returns for upstream firms are particularly sensitive to downside risk and credit risk. We also find that including the change in WTI or Brent crude prices offers a notable increase in explanatory power for these bond returns. This also holds for the real commodity price factor, to a lesser extent. Consistent with the oil majors, little is gained from including any of the other activity indicators in the regression.

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Is the cake a chimera? Trade-offs between productivity and costs in unconventional oil and gas production

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Abstract

The production of unconventional resources in the U.S. affects the domestic and global supply of crude oil and natural gas, and consequently, the supply of its derivatives, domestic and global energy prices, and the environment. However, little we know about how economic variables affect, endogenously, choices regarding drilling and completion strategies, upstream production, and hence, oil and gas supply. When the oil price is low, some upstream companies seem to focus their attention on maximizing the first-year production. This strategy might entail larger completion costs and well interference, being cost-inefficient in the long-term. We propose production and costs functions that reflect unconventional production and estimate optimal development strategies. We use the distance

between stages and well interference as novel factors that determine productivity. This model is useful as stand-alone or as part of an energy system not only to analyze the effects in the supply of unconventional oil and gas due to changes in economic variables, but also to measure policy effects, such as environmental taxes or other regulations that aim to cut carbon emissions.

Methods

We developed a production model for unconventional oil and gas. The production and completion cost are a function of the distance between stages, or completion unit, and represent the intensity of completion. Hence, the inputs used for the well completion are proppant and water per completion unit, which normalize the completion process with respect to lateral length and number of stages. Furthermore, we also include the effects of well interference, found when the distance between stages is too close. In that case, the fractures and extraction of oil and gas interferes between completion units, reducing their productivity. The drilling cost function that includes economies (dis-economies of scale) with respect to lateral length. We also use a constant elasticity of substitution production function to account for the large complementary found between proppant and water used in the completion of wells.

We used the data of drilling and completion costs from unconventional wells in the Delaware basin, made publicly available by University Lands, and production data from IHS Markit to estimate long-term cost functions in the Delaware Basin, and motivate the proposed costs and production model. Moreover, we use the data to calibrate and simulate different scenarios of prices and relevant parameters.

Results

The optimal solutions for proppant, water, lateral length, and the number of stages are responsive to different strategic objectives, prices, economies of scale, and subsurface characteristics. The theoretical results show that companies that focus only on completion's productivity have larger short-term production, but also larger well interference, and larger costs. The model is also coherent with the drilling, completion and production data from the Delaware basin.

Adapting Hotelling to Microeconomic Empirical Work in Oil and Gas Extraction

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Abstract

How useful is economic theory model in explaining the decisions of fracking firms in the oil and gas industry? Anderson, Kellogg, and Salant (2018) (AKS) was successful in understanding the observed facts that for oil and gas extraction, drilling activity covaries with oil prices, while production from existing wells does not respond to price shocks. They reframe the Hotelling model of the optimal extraction of a nonrenewable resource as a drilling problem. However, the model is limited in its ability to rationalize

why firms extract simultaneously from low and high quality deposits. In this research project, we rationalize observed behavior by reformulating the Hotelling/AKS model to 1) incorporate resource quality and 2) combine it with Rust-style discrete choice dynamic programming (DCDP). We then use data from North Dakota to empirically test our model.

Methods

The two main goals of this research project are:

- to construct a model of drilling behavior for how geological features affect which wells and how fast wells are developed, as well as how wells are operated
- to study the model's predictions; and
- to validate the model empirically

We modify AKS in two ways. First, we introduce heterogeneity in resource quality. Second, we allow firms to experience deposit-specific cost shocks. These modifications lend themselves to a Rust-style DCDP framework. Cost shocks serve to rationalize empirical behavior without the need to explicitly model capacity constraints or unrealistic cost functions to my model. We show how to the model accommodates both exogenous and endogenous prices. The model predicts that:

1. firms will drill high and low quality resources at the same time, but
2. the probability of a particular location being drilled is increasing in resource quality.
3. Negative price shocks like one during the second half of 2014, will cause firms to halt drilling of low-quality resources

It is essential to estimate the geological characteristics of each well site to validate the theory- based predictions. Yet, in general, such properties are unobservable. To overcome this obstacle, we employ Robinson's partially linear model that deals with the spatial distribution of geological properties non-parametrically. Finally, we estimate the DCDP model of extraction conditional on resource quality and prices. To validate it, we explore its out-of-sample prediction properties in both the time series and cross-sectional dimensions.

Results

Data on drilling and production in North Dakota’s Bakken shale reveals two things. First, firms have not drilled their wells in decreasing order of geological quality as theory predicts. Instead, they have drilled high and low quality resources simultaneously. Second, the probability of a deposit being drilled is increasing in resource quality. Third, drilling of low quality resources responded more to the negative price shock in 2014. We show analytically that the first prediction cannot be rationalized in the AKS framework without resorting to capacity constraints or unrealistic cost functions. To rationalize this behavior, we cast the AKS model as a DCDP problem, and we demonstrate the model’s properties using simulation. We explore how the cost shocks we introduce rationalize the empirical behavior we see.

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Policy issues

Exploring the Role of Foreign Aid in Southeast Asia's Energy Transition

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Abstract

The rapid deployment of modern renewable energy generation capacity in the fast growing Southeast Asian countries will be crucial to ensure that the region can meet its increasing future energy demand in a sustainable way. However, many countries will need assistance through international cooperation and official development assistance to develop their sustainable energy sources. The three East Asian donor states Japan, South Korea and China are particularly crucial because they account for a large share of aid disbursements to the region and also serve as development role models for many of the recipient countries. All three donors are signatories of the Paris Agreement and the 2030 Agenda and thus committed to the global goals of climate protection and sustainable energy development. This paper is based on an analysis of official aid databases and second-party data to explore the details of energy-related aid contributions of the three East Asian donor states to Southeast Asia during the last decade. The findings indicate that all three states contradicted their own international pledges by financing fossil fuel power generation projects in many countries in the region. Although recent policy changes in Japan give cause for optimism, the opacity of China's energy-related aid contribution in combination with its renewed support for domestic coal power are worrying signs for the future energy development in Southeast Asia and beyond.

Methods

This paper is based on an analysis of official aid databases and second-party data.

Results

The findings indicate that all three states contradicted their own international pledges by financing fossil fuel power generation projects in many countries in the region.

Capacity at Risk: A Metric for Robust Planning Decisions under Uncertainty in the Electric Sector

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Abstract

Many decision contexts are characterized by deep uncertainty where there is disagreement about values and probabilities such as energy sector investments under policy and technological uncertainty. Although there are emerging methods for decision analysis in these contexts, many approaches are computationally burdensome, and there are few simple metrics to guide analysts and decision-makers on whether more sophisticated methods are appropriate and to prioritize information gathering on uncertainties. Here we introduce a screening metric called "capacity at risk" for identifying the most decision-relevant uncertainties and for understanding which investments could be robust and which are more uncertain across a range of different futures. This metric is applied to an illustrative example of electric sector decarbonization in the United States using a detailed capacity planning and dispatch model. Scenario results demonstrate the importance of climate policy targets and timing on decisions, while uncertainties such as natural gas prices and renewable costs have more moderate impacts on planning. We also apply the capacity at risk framework to other prominent U.S. electric sector scenario analysis. These comparisons suggest that commonly used scenarios may understate uncertainty, giving decision-makers a misleading sense of portfolio risk and understating the value of frameworks that explicitly assess decisions under uncertainty.

Methods

Many decision contexts are characterized by deep uncertainty where there is disagreement about values, system dynamics, and probabilities such as energy sector investments under policy and technological uncertainty. Although there are emerging methods for decision analysis in these contexts (Baker, Bosetti, & Salo, 2020), many approaches are computationally burdensome, and there are few simple metrics to guide decision-makers, analysts, and other stakeholders on whether more sophisticated methods are appropriate and to prioritize information gathering on uncertain variables. Existing metrics such as the expected value of information and the value of the stochastic solution typically assume the availability of a stochastic model (Bistline, 2015). Given the high computational costs of stochastic models, the framework developed in this paper uses deterministic sensitivity analysis to help stakeholders think about which uncertainties materially impact decisions and to prioritize model development, more detailed analysis, and probability assessments. These deterministic outputs can be used to convey which uncertainties matter, which capacity investments seem robust across different, and which capacity could be at risk. This metric and proof-of-concept analysis are first steps toward systematically exploring uncertainty in decarbonized energy systems and determining which uncertainties require additional effort to quantify (and the value of using frameworks that explicitly evaluate decisions under uncertainty such as stochastic planning or robust portfolio analysis).

For each uncertain variable and its realizations (i.e., all outcomes or states-of-the-world), "capacity at risk" is defined as the technology-specific difference between investment in that state and the minimum investment across all states (or scenarios). The minimum investment provides a conservative lower bound on "robust capacity" for that particular uncertainty. The maximum capacity at risk for a given uncertainty is the maximum technology-specific variation across all states, which again provides a conservative upper bound on capacity risk. Comparing the maximum capacity at risk and minimum robust capacity across uncertainties provides a screening tool for identifying decision-relevant uncertainties that have the largest effects on robust decisions and at-risk capacity. This metric is analogous to the commonly used "value at risk" metric for understanding the risk of loss for investments under uncertainty, though a key difference is that capacity at risk does not require probabilistic information or analysis (only to enumerate possible outcomes without attaching likelihoods to these states).

To provide an illustrative example of capacity at risk in a decision-relevant domain, a numerical analysis is conducted for electric sector decarbonization in the U.S. This analysis uses a model of end-use adoption linked to a power sector capacity planning and dispatch model with technological, temporal, and spatial detail. The model—EPRI's Regional Economy, Greenhouse Gas, and Energy (REGEN)—is fully documented in EPRI (2020). We examine the following sensitivities in this analysis: climate policy target definition (i.e., eligible technologies), climate policy timing, renewable/storage costs, natural gas prices, and other technological costs.

Results

REGEN Results

The results from the capacity expansion suggest that climate policy target definitions and timing matter more for near-term investments than uncertainties related to technological cost and gas prices.

Across all zero emissions scenarios, there is a significant acceleration of investments and dependence on emerging technologies. The "Net-Zero" scenario (i.e., net CO_2 emissions in the power sector are zero so that any emissions produced are balanced by an equivalent amount of removals), has the broadest technological portfolio by construction with high wind and solar deployment combined with negative emissions from bioenergy with carbon capture to enable gas to balance renewable variability. The "Carbon-Free" scenario (i.e., electricity generation does not use fossil fuels and does not emit CO_2), entails a rapid build out of nuclear and storage (including batteries and hydrogen) to balance larger solar and wind expansions. The "100% Renewables" scenario has nearly double the capacity investment requirements of the "Net-Zero" scenario.

Capacity at Risk Metrics

The technology portfolio for minimum robust capacity encompasses wind, solar, and storage technologies. Henceforth, these technologies are the "robust investments," irrespective of the climate policy timing. The highest capacities at risk are solar and wind technologies, because of significant investments in near-term "Carbon-Free" and "100% Renewables" scenarios. The overall risk-ratio—the maximum capacity divided by minimum robust additions—is 83, which indicates higher levels of risk associated with climate policy target definitions and timing.

The minimum robust capacity is higher and capacity at risk lower for other sensitivities considered in this analysis, including renewable costs and natural gas prices. Renewables become the largest producer under many scenarios, and shares depend on policy and technology assumptions and vary by region.

Application to Other Analyses

We apply capacity at risk metrics to the commonly used U.S. EIA's *Annual Energy Outlook 2021* and NREL's *2020 Standard Scenarios*. These comparisons suggest that the selected uncertainties for the analyses do not lead to significant variation in investment-related outputs. This result indicates that these assessments may be underestimating risk by omitting uncertainties such as climate policy design and timing and instead focusing on uncertainties related to fuel prices, technology costs, and demand growth.

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Renewable Energy Policies and Innovation in Complementary Technologies

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Abstract

Renewable energy sources, such as solar and wind, provide substantial environmental benefits by reducing carbon emissions and other pollutants from the electricity sector. Despite technological innovation and impressive growth rates over the last decade, solar and wind energy are inherently variable, which challenges more wide-scale use of these technologies. Complementary technologies that address the intermittent nature of solar and wind, but are not considered renewable themselves, can help boost renewable energy use. For example, energy storage technologies can store solar energy generated during the day to supply power after the sun has set (Lazkano et al., 2017). Natural gas combined cycle plants can ramp up and down quickly to offset fluctuations from renewables (Verdolini et al., 2018).

Previous research has shown that environmental policies targeting renewable energy can drive innovation in solar and wind technology (Johnstone et al., 2010). However, there has been little research exploring whether such policies have the positive side effect of spurring innovation in complementary technologies as well. This study aims to evaluate if renewable policies also induce innovation in complementary technologies that support renewable integration.

Methods

We use patent application data from the European Patent Office's PATSTAT as a measure of innovation in complementary renewable technology fields. We identified innovation in two specific technology fields: 1. enabling storage technologies, such as energy storage using batteries or capacitors, thermal or mechanical energy storage, as well as hydrogen technology and fuel cells; and 2. combustion technology with mitigation potential, such as natural gas combined cycle with fast-start capabilities. We identified relevant patents in these two technology fields using Cooperative Patent Classification (CPC) codes.

In order to measure renewable policy stringency, we used data drawn from the Environmental Policy Stringency (EPS) dataset gathered by OECD. The EPS is based on quantitative measures of relative environmental policy stringency across space and time. The measures we looked at for renewable energy policies include both market and non-market policies, including feed-in-tariffs for solar and wind power, tradable certificates for carbon dioxide, renewable energy certificates, carbon and other environmental taxes, as well as government research and development (R&D) subsidies.

For this study we use a negative binomial to model the relationship between renewable policies and complementary renewable technology innovation in OECD countries from 1992-2014. Where *i* denotes country, and *t* denotes year, we ran the following regressions for each technology field (*Patents*) and a vector of policy variables (*Policy):*

$$\textit{Storage Patents}_{i,t} = \boldsymbol{\beta_n(Policy_{n,i,t})} + \boldsymbol{\beta_y(Controls_{y,i,t})} + \alpha_i + \sigma_t + \varepsilon_{i,t} \quad \text{(eq. 1)}$$

$$\textit{Combustion Patents}_{i,t} = \boldsymbol{\beta_n(Policy_{n,i,t})} + \boldsymbol{\beta_y(Controls_{y,i,t})} + \alpha_i + \sigma_t + \varepsilon_{i,t} \quad \text{(eq. 2)}$$

We include a vector of relevant controls for each technology (*Controls)*, including energy consumption, electricity prices, as well as coal and natural gas prices. We also include country dummies (α) to control for all time-invariant characteristics as well as year-dummies (σ) to address attrition.

Results

Our preliminary results find that more stringent renewable policies in OECD countries are sometimes associated with increased innovation in complementary technologies, as measured by patents. The policies with the greatest impact include public research and development (R&D) spending and renewable energy certificates, such as Renewable Portfolio Standards (RPS) in the United States. A one-unit increase in R&D spending for renewable technologies leads to about a 15% increase in combustion and storage technologies. Renewable energy certificates lead to statistically significant increases in combustion technology as well as energy storage technologies, but to a smaller extent. We also find environmental taxes drive innovation in storage technologies, but not in combustion technologies.

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Renewable energy

Feasibility Analysis of Green Energy Community According to Sufficiency Philosophy: Ayutthaya Elephant Palace and Royal Kraal Model

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Abstract

With a view to reduction of global warming, the United Nations and the Thai government recognize the importance of renewable energy for moving forward to a sustainable green society. This paper considers the implementation of a project of Ayutthaya Elephant Palace and Royal Kraal, focusing on the feasibility study of green energy generation from community waste. Such generation involves changing the waste material from dung and discarded food of elephants (which incorporates a cost in management, as well as pollution problems, and fire risk from methane) into biological energy and soil conditioner with feasibility analysis involving economic, technical engineering, legal and environmental, and operational considerations. The result shows that under financial analysis, the system should cost USD 130,735.23 with a payback period of 2.19 years. However, under economic analysis which includes financial and social analysis, the payback period of this project should be significantly shorter due to a number of positive environmental side effects. Looking forward, we anticipate that Ayutthaya Elephant Palace and Royal Kraal will become the model for net zero-energy communities according to Sufficiency Economy Philosophy (SEP). We recognize that green energy communities are the next step in renewable energy efficiency to meet stability, wealth and sustainability.

Methods

The research in Ayutthaya Elephant Palace and Royal Kraal, in the middle region of Thailand, was conducted from April 1, 2020 to March 31, 2021. Data collection was done using the methods of in-depth interviews and documentary research to determine the transcriptionally active part of the biogas energy and soil conditioner with engineering, environmental and economic value.

1. Location

Phra Nakhon Si Ayutthaya Province was one of the world's largest urban areas and, as a result of an extension of the World Heritage property listings is under restoration which will cover the complete footprint of the city as it existed in the 18th century (UNESCO, 2021). As a result, this project plant cannot be set at Ayutthaya Elephant Palace and Royal Kraal, and Chang Phaniat Luang Village. However, to save cost of transportation, the project location is nearby on the opposite side of Chang Phaniat Luang Village, with Lop Buri Pa Sak River in the middle.

2. Data

The data for financial analysis, including energy prices, interest rates, and costs of investment, are collected from the National Statistical Office (NSO), Ministry of Energy of Thailand, PTT Public Company Limited (PTT), Bank of Thailand (BOT) and Energy Research and Development Institute - Nakornping, Chiangmai University. Google map is used to prepare the geo-synchronized layout for the proposed land and water body. In-depth interviews include the representatives of Ayutthaya Elephant Palace Royal Kraal, Co., Ltd. (1 person), Chang Phaniat Luang Village (3 persons), engineering expert (1 person), environmental expert (1 person), economics expert (1 person), government officer (1 person), and tourist (3 persons).

3. Feasibility Analysis

This paper applies the feasibility study model of Mahatgroup (2021) to involve the following: 1) economic feasibility, 2) technical feasibility, 3) legal (and environmental) feasibility, 4) operational feasibility, and 5) schedule feasibility (see Figure 4). However, the paper employs an economic feasibility study (EFS) to demonstrate the net benefit of 500 cubic meters (m^3) of biogas and fermented manure from the biogas plant process project with a view to accepting or rejecting. EFS as the method for determining the efficiency of this project, which helps in identifying profit against investment in relation to the project. The EFS in this study focuses on cost-benefit analysis (CBA), which summarizes the revenues and costs involved with the project, with cost and time being the most essential factors.

CBA involves two widely used frameworks for evaluating policy and action projects. Alternatives are evaluated based on the net present benefits, or total benefits more than total costs, and typically involve estimation of the financial and social analyses. However, this paper focuses on financial analysis. Therefore, the project's results will be presented in three forms for CBA: Payback Period (PP) or Break-Even, Net Present Value (NPV), and Internal Rate of Return (IRR) (Boardman et al., 2004; Yanga, 2012; Department of Alternative Energy Development and Efficiency, 2021).

Results

From documentary research, the production of biogas from renewable resources or organic waste can grow in importance as a sustainable process for energy production (Weiland, 2003; Yadvika et al., 2004). We plan to create an innovation of biogas production using a CMU-Hybrid Anaerobic Reactor which employs modern innovative technology through Thai craftsmanship in the conversion of elephant dung and food waste into biogas. The technology from Energy Research and Development Institute - Nakornping has been proven to effectively convert pig manure into biogas by way of a 500 cubic metre

(m^3) biogas plant project.
According to literature review and in-depth interviews of people involved, the output of the biological energy and soil conditioner operation system has value in economic terms. The feasibility analysis involves these assumptions: 1) biogas of one cubic metre has a heating value equivalent to 0.46 kg of LPG (Kamiluddin et al., 2018), 2) the price of LPG from biogas is 17.28 baht/litre which is the average price in April 2021 (Energy Policy and Planning Office of Thailand, 2021), 3) the price of soil conditioner from biogas production is 5 baht/kg, 4) depreciation is four years, 5) the Weighted Average Cost of Capital (WACC) or interest rate is 6%, 6) the Corporate Income Tax (CIT) rate is 15% for Small and Medium Enterprises (SME), 7) Cash Conversion Cycle (CCC) is 15 days, and 8) the currency unit of this analysis is baht, with the exchange rate of 32.13 THB = 1.00 USD.
The cost of the system can be estimated at around 4,200,000 baht to produce around 300 cubic metres/day of biological energy and 1.7 tons/day of soil conditioner from 10 tons/day of elephant dung and discarded food. The results show that the payback period, which is the time span in which the cost of the yield becomes equal to the capital invested in installation, is expected to be about 2.19 years. Net Present Value (NPV), which is the difference between the present value of cash inflows and the present value of cash outflows over a period of time, will be 30,610,759 baht. The Internal Rate of Return (IRR), which is the discount rate that makes the NPV zero, will be 53%. Therefore, we should invest in this eco-friendly project.
However, the Energy Policy Administrative Committee (EPAC) expects the use of 248 million baht monthly from the Oil Fuel Fund Administration Office to cap the price at 318 baht per standard LPG cylinder (15 kg), down from 363 baht per cylinder, or a subsidy of three baht per kg (Praiwant, 2020). Hence, the LPG price in the country is lower than the equilibrium price. If this policy is changed, this energy community project will sell higher and the simulation results will be changed. The payback period will be around 2.13 years, NPV will be 32,690,229 baht, and IRR will be 55%. Therefore, without the government subsidy, more project value is created.

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Decomposing the Effects of Renewables on the Electricity Sector

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Abstract

Renewables in the United States electricity sector have experienced rapid growth over the last decade, increasing from roughly 4% of the generation mix in 2010 to more than 10% in 2019 [1]. This trend is poised to continue with renewables accounting for a majority of planned capacity expansions in 2021 [2]. Renewables offer the potential for a dramatic reduction in electricity sector pollution, and continued cost reductions in these technologies may provide lower electricity prices. Yet, the growth of renewables is not without concern. Predominant renewable resources—wind and solar energy—possess unique characteristics that may pose both technical and economic challenges to the operation of electricity grids.

In this paper, we decompose the overall effects of these renewable resources on the electricity grid by estimating how each of these characteristics—zero marginal cost, intermittency, and uncertainty—impacts electricity market prices and outcomes [3]. While previous work has estimated the overall effect of renewable resources on prices and volatility,[4] in this paper, we decompose the impact of each of these characteristics.

First, we study the grid impacts from renewable energy's zero marginal cost. Because of this, renewable energy is always dispatched first. When electricity markets experience greater levels of renewable energy generation, less conventional generation is dispatched, yielding a lower market- clearing price all else equal. The size of this price reduction depends on the slope of the conventional supply curve in the region where the demand curve would have intersected the supply curve absent the renewable energy generation. We call this a residual demand effect, where residual demand refers to total electricity demanded less renewable energy.

Second, we examine the impacts of intermittency. Conditional on built capacity, renewable production is determined by exogenous weather-related factors, such as wind speed and solar irradiation, which are highly variable across hours and seasons. As a result, the residual demand for conventional resources is also variable throughout the day and season. The intermittency in renewable generation and residual demand for conventional generation would be expected to increase volatility in the market-clearing price, even when holding conventional generation supply curves constant.

Third, we study uncertainty. Because renewable production is driven by exogenous weather-related factors that are uncertain, renewables possess unique forecasting challenges. That is, forecasting renewable production arguably includes more forecast error than forecasting conventional production. An electricity portfolio with a larger share of wind and solar may be expected to come with a larger amount of uncertainty in production and forecast error. Yet, the ability of grid operators to forecast renewable energy generation is expected to improve with experience. Additionally, because wind and solar availability are highly location-specific, aggregate forecasting errors are expected to be dampened with expanded geographic deployment of renewable capacity. While more forecast error would be expected to increase price volatility, the impact of more renewable energy on total forecast error is unclear.

Methods

We use econometric models and hourly and sub-hourly data from the Texas electricity market for the year 2012–2019 to study each of these anticipated impacts of renewable wind energy. This market has one of the highest penetrations of wind energy among US electricity markets, growing from roughly 10% in 2010 to nearly 23% in 2020.[5] Additionally, the Texas electricity grid has little capacity for trade with adjacent electricity markets, making it well-suited to use as an isolated laboratory in which to study these effects. The scope and time series of data available from ERCOT allow for straightforward causal identification strategies.

Results

In preliminary results, we find that higher levels of wind generation lead to lower wholesale electricity prices, which we attribute to the residual demand effect. We also estimate hour-specific impacts of wind generation and find that this residual demand price effect is strongest during the morning around

7:00am, and in the afternoon and evening from 2:00pm to 6:00pm. Both of these periods correspond to hours in which residual demand is increasing, due to an increase in demand and/or a decrease in wind generation. These estimates are consistent with our expectation of a hockey-stick shaped conventional-fuel electricity supply curve.

We then regress several measures of price volatility on hourly wind generation. When controlling for prices, wind energy increases price volatility on average. However, unconditional on prices, more wind generation is associated with lower price volatility, since wind energy decreases prices, and lower prices decrease volatility. Again we find heterogeneous effects across the hours of the day, in levels consistent with our expectation of a hockey-stick shaped conventional-fuel electricity supply curve. That is, wind energy increases volatility more when residual demand is higher, around 7:00am and from 2:00pm to 6:00pm. This finding is consistent with our expectation that small changes in residual demand lead to larger price changes and higher levels of volatility when the residual demand curve is higher and intersects the supply curve along its steeper regions.

Finally, we estimate the impact of forecast uncertainty on prices and volatility. To do so, we develop a measure of forecast error by comparing day-ahead predictions of wind generation from the Texas grid operator to actual wind generation. We regress prices and volatility on this measure of forecast error. As expected, more wind than the grid operator expected decreases prices and less wind than expected increases prices. We also find that a unit of realized wind has a smaller impact on prices than a unit of un-forecasted wind. This result suggests that conventional resources that grid operators commit to in advance are lower cost than conventional resources called upon in the short term to address forecast error.

References

FOOTNOTES

[1] U.S. Energy Information Administration's Electric Power Monthly

[2] U.S. Energy Information Administration's Today in Energy, January 11, 2021.

[3] The term intermittent refers to solar and wind energy, as renewable resources such as hydropower and geothermal power are not intermittent. We will use the term 'conventional' to refer to fossil-based resources.

[4] See Woo et al (2011), Ketterer (2014), and Bushnell and Novan (2018), among many other. Wurzburg, Labandeira, and Linares (2013) provides a comprehensive review of the early literature on this topic.

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Reducing transmission expansion by co-optimizing sizing of wind, solar, storage and grid connection capacity

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Abstract

With recent cost declines in variable renewable energy (VRE) resources - particularly wind and solar technologies - and the need for increasing VRE penetration to reduce carbon dioxide emissions, VRE technologies have become more popular and more widely deployed. However, with the variability of VREs, the growing integration of VREs in the electricity grid will require significant flexibility. Energy storage resources, particularly lithium-ion batteries, have been cited as a possible technology to balance VRE flexibility on the grid. With declining costs, batteries are of growing interest in a low-carbon future for energy system planning [1, 2, 3]. Utility, grid-scale batteries can be deployed in two manners: 1) standalone and independently sited, and 2) co-located with other generators. There has been increasing interest in co-located VRE-storage generators, both PV and battery and wind and battery resources, due to lower systems costs, policy incentives, and system value.

Traditional power system models fix the grid capacity equal to the capacity of new solar PV or wind. Generally, PV capacity is oversized 1.3 times the amount of grid capacity (including inverter capacity), and wind capacity is sized at the fixed ratio of 1 MW grid capacity built for 1 MW of wind capacity built [3]. However, the optimal ratios or grid sizing may vary significantly from the standard values, particularly with the ability to co-locate resources and in different regions.

Thus, the objectives of this study were 1) to determine the impact of grid co-optimization on the new-build capacity of VRE resources, and 2) to model co-located DC-coupled VRE and storage resources (both co-located PV-battery and wind-battery resources) in long-term electricity system capacity expansion models.

Methods

In the first part of this study, a novel formulation for modeling variable renewable energy (VRE) resources with 1) co-optimized grid connection, and 2) co-located VRE and storage resources was implemented in GenX, an open-source, least-cost optimization, power system capacity expansion model [4]. The module enables users to optimize grid capacity built for various VRE sites and to enable developing DC-coupled storage and VRE sites.

The second part of this study analyzes the impacts of grid co-optimization and co-location on the variation in total system cost, new VRE capacity, and new grid capacity using the novel formulation. We study the impacts using a six-region Western Interconnection model for 2030. The six regions included northern California, southern California, New Mexico and Arizona, the Pacific Northwest, Wyoming and Colorado, and Idaho, Montana, Utah, and Nevada. This model utilizes interregional power flow transmission constraints, hourly resolution of resource capacity factors, linearized unit commitment decisions for thermal generators, capacity reserve margins, current tax credit policies, and time domain reduction methods for the number of weeks modeled of a full year.

The real-world input dataset for the Western Interconnection was created using PowerGenome, an open-source model that pulls data from numerous sources, including EIA, NREL, and EPA, for electricity system modeling [5]. Additionally, cost analysis for co-located resources and grid connections was conducted based on recent NREL reports to determine the bottom-up costs for resources (VRE and storage modules, inverter, and other substation costs) [3, 6].

The novel formulation was tested on 12 scenarios considering various renewable policies and cost trajectories of VREs in 2030. Three scenarios were run to compare the effects of modeling VREs with co-optimized grid connection and co-location of storage on cost-optimal system composition. The fixed ratio scenario assumes that there is 1.3 MW of PV built for every 1 MW of grid connection built and 1 MW of wind built for every 1 MW of grid connection built. These scenarios align with the current DC-to-AC ratios and grid connections built in traditional power system models. Additionally, the fixed ratio scenario models only standalone options to build batteries, PV, and wind. The second scenario, the co-optimized ratio scenario, does not constrain the capacity of grid connection built in comparison to the capacity of PV or wind built to enable grid connection capacity co-optimization. This scenario only enables standalone options for technologies to compare the effect of co-optimizing grid connection on capacity expansion of VREs. The third scenario, the new co-located model scenario, assumes the co-optimized scenario with the ability to co-locate PV and storage or wind and storage resources. Two different policies were additionally run: 1) current policies, and 2) 80% clean energy standard (CES) to showcase short-term decarbonization pathways inclusive of VRE and storage technology options. Using NREL's 2020 ATB scenarios, two different VRE cost projections were utilized. Moderate and low cost sensitivity analyses were run as different scenarios [6].

Results

The objectives of the results were to determine 1) how co-optimizing the grid to VRE capacity would compare to the current scenario with a fixed ratio between the two capacities, and 2) how offering the option to build hybrid systems would impact the quantity and rate of new-build of VRE and storage technologies. Preliminary results indicate that co-optimizing the grid capacity enables more battery capacity to be built with little to no changes in the capacity of VREs built. Co-locating VRE and battery resources enables significantly more battery capacity to be built with slight changes in the capacity of VREs built. We hypothesize that the ability to co-optimize co-located resources will reduce the need for inter-regional transmission expansion and increase co-located capacity built.

Further analysis on incorporating capacity reserve margins, policy incentives (both investment tax credits and production tax credits), and quantitative impacts on the changing network and resource capacities will be conducted.

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Retire, repair, or repower? Wind investments in a maturing industry

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Abstract

In the two decades 2000-2020, U.S. wind generation capacity grew nearly fiftyfold—from about 2,600 to approximately 126,000 MW (DOE). This creates a novel problem for the “new” technology of wind: nearly a third of wind capacity is 10 years old or older. As this capital stock ages, the timing of replacement of turbines presents an interesting and important economic question. Turbine productivity declines over time (Staffell and Green 2014, Hamilton et al., 2020), and as capital gets older the chance of failure may also increase. These types of depreciation are common to other types of capital and have been the subject of optimal replacement studies in the past (Rust 1987). Wind generation presents a novel set of issues as well, because as more capacity has been added, the dynamics of the underlying electricity market have changed. Lower prices attributable to both increased renewable generation and switching to low-cost natural gas have eroded turbine value. This has an ambiguous effect on

replacement timing, depending heavily on the rate of technical improvement for wind turbines and associated infrastructure. A second important factor is the shifting policy environment for wind investment, as investment and production tax credits have been altered, expired, retroactively applied, and discontinued. These policy levers directly affect the value of existing and replacement capital.

Reliable long-term wind project are critical inputs into energy policy analysis, long-run resource adequacy assessments, and project investment analysis. Prominent existing analyses mostly neglect the role of physical depreciation and the potential for retirement or repowering decisions. Staffell and Green (2014) found a 1.6 percent decline in output per year on average for UK wind projects, a decline that boosts the estimated levelized cost of energy by nearly 10 percent. More recently, working with data on U.S. wind power projects, Hamilton et al. (2020) found an age-related performance decline ranging from 0.53 percent per year for older projects to 0.17 percent per year for newer projects. We conduct a similar study focused on the Texas wind power fleet. We then extend the analysis in order to make it more useful for long-term planning efforts, both policy and commercial, by adding a model of optimal wind generation replacement. That replacement explicitly accounts for physical depreciation of capital, heterogeneous site value, and the changing market and policy environments that affect investment returns.

Methods

Focusing on the Texas wind fleet, we begin with publicly-available data and the analytical techniques used in earlier studies of wind project depreciation with age. Texas has been a leading state in wind investment, and detailed data are available from the grid operator (ERCOT). We exploit rich data from ERCOT since 2011 to further understand the operational choices that are made by operators under changing weather, grid, and policy conditions. The narrower focus, as compared to national focus of Hamilton et al. (2020), allows a closer look at individual project and turbine characteristics. It also permits a more relevant incorporation of policy and grid environments in ways that potentially aid causal interpretation from the data. The data and analysis allow us to present calibrated simulations and offer causal interpretation of operational choices.

Empirical work is currently ongoing. Preliminary analysis offers support for the stylized facts emerging from earlier studies: Wind projects in Texas show a decline in performance with age, projects supported by the Production Tax Credit show a sharper decline after the production subsidy ends, and newer projects appear to decline with age at a slower rate than newer projects. The analysis continues with an optimal replacement model similar to Muehlenbachs (2015), calibrated to predict project retire/repair/repower decisions and produce sounder forecasts of energy production from existing wind projects.

Results

As the wind energy industry in the United States matures, wind farm operators will increasingly find capital ageing and replacement decisions central to their operations. Other parties also have an interest in those decisions, including lenders and system operators seeking to forecast future capacity and generation. Policymakers are also vested in this decision model as incentive to promote further penetration of renewable electricity generation.

Many states, localities, and corporations have committed themselves to renewable energy standards or carbon-free energy sources, with the stringency of such standards increasing steadily over time. (Barbose, 2019) Wind energy industry performance over the next three decades is critical to attaining these policy goals. Current models fail to reflect the ageing of wind infrastructure and maturation of the wind energy industry is a realistic manner, and we explicitly address that failing.

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State-Level Trends in Renewable Energy Procurement via Solar Installation versus Green Electricity

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Abstract

Today, residential consumers have many more options for procuring renewable energy beyond installing distributed solar. There is an emerging market for "virtual" options ranging from opt-in utility products (utility green pricing) to opt-out municipal aggregation (community choice aggregation or CCA), which can increase the renewable content of grid electricity. However, it is unclear how this increased choice affects consumer preferences for procuring renewable energy. This paper investigates the relationship between green electricity (virtual) and distributed solar (physical) options aggregated at the state level. We propose that these options can be considered complements, where there is joint demand, or as substitutes, where consumers satisfy their demand with one option. Via panel data from 2016 to 2019 for all US states, we estimate the relationship between virtual green electricity procurement and distributed solar generation while controlling for policy, resource availability, and demographics. Preliminary results suggest that although there is no observed relationship between green electricity and solar installation across all states, there is a negative relationship between these two types of procurement in states with renewable portfolio standards, indicating they act as substitutes in those states. This effect may be driven by differences in utility-level programs and challenges measuring a relationship in states with fewer renewables. Consumer preferences are likely to evolve as more choices are available and defaults change. This work has implications for how these options are marketed and long-term grid planning.

Methods

We use a regression model with interaction terms and robust standard errors to estimate how virtual procurement options influence physical procurement (i.e., residential solar installation). This model controls for policy, resource availability, and demographics as well as time fixed effects. In this state-level analysis, data are available for all 50 states as well as Washington DC with one observation per year for three years from 2016-2019 (N = 204).

To estimate physical procurement per state per year, we use Energy Information Administration (EIA) data on small-scale PV generation to estimate residential solar generation in MWhs. To make comparisons across states, we calculate the percent of total energy generation that is residential solar per state per year. The data are highly skewed toward zero, so a log transformation with a log-linear correction is used to normalize the data.

To estimate virtual procurement per state per year, we use National Renewable Energy Laboratory (NREL) data on voluntary renewable energy procurement (Heeter & O'Shaughnessy, 2019). Virtual procurement is the sum in MWhs per state per year of Utility Green Pricing, Competitive Suppliers, Unbundled Renewable Energy Credits (REC), Community Choice Aggregation (CCA), and Power Purchase Agreements (PPA). Similar to the physical procurement measure, we calculate the percent of total energy that is virtual renewable procurement per state per year and use a log transformation with a log-linear correction.

In addition, we control for (1) policy, (2) resource availability, and (3) demographics. For policy, we use binary variables from the Database of State Incentives for Renewables & Efficiency (DSIRE) for Renewable Portfolio Standards (RPS), CCA-enabling legislation, electric sector restructuring, state-wide rebates for distributed solar, and state-wide tax credits for distributed solar. To account for resource availability, we include solar insolation per state from NREL and average electricity price per state from the EIA. We also control for other demographic variables from U.S. Census including average household income, percent female population, percentage non-white population, and the average age in the state. The model includes Democrat-lean and the political party each state voted for in the 2016 elections from the National Archives. In addition, we include an interaction term between RPS and virtual procurement to account for different trends in states with an RPS.

Results

In a Pearson correlation analysis, we find that the proportion of residential distributed solar (physical procurement) tended to be higher in states with rebates ($r(203) = 0.54$, $p < .001$), higher household incomes ($r(203) = 0.45$, $p < .001$), and higher electricity costs ($r(203) = 0.39$, $p < .001$). The proportion of green electricity purchases (virtual procurement) tended to be higher in states with an RPS ($r(203) = 0.27$, $p < .001$) and higher solar insolation ($r(203) = 0.18$, $p = .011$). Between 2016 and 2019, virtual procurement nearly tripled, increasing by 173% across the four years studied. The vast majority of virtual procurement was from PPAs, followed by Competitive Suppliers. States with higher populations, such as California and Texas, tend to have higher amounts of both virtual and physical procurement.

The regression model suggests that, when controlling for policy, resource availability, and socio-economic variables, $R^2 = .59$, $F(18, 185) = 17.27$, $p < .001$, the virtual option has no observable impact on the physical option. However, when an RPS is present, the relationship between virtual and physical procurement is negative in an interaction term, $B = -0.19$, $SE = 0.11$, $p = .044$, suggesting that when an RPS is in place, virtual and physical options are substitutes. This may be because in states with an RPS (such as Maine, Colorado, and New Mexico), utilities employ more marketing, which may frame choices as substitutes.

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Development in long-duration energy storage technologies

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Abstract

We review candidate long duration energy storage technologies that are commercially mature or under commercialization. We then compare relevant technical and economic characteristics including land area, idle loss rate and average capital cost with varied durations. The technology landscape may allow for a diverse range of storage applications based on land availability and duration need, which may be location dependent. These insights are valuable to guide the development of long-duration energy storage projects and inspire potential use cases for different long-duration energy storage technologies. This analysis also lays the foundation for future relevant modeling and decision-making studies that implement emerging long-duration energy storage.

Methods

In selecting which technologies to compare, electricity-in-electricity-out technologies were prioritized. We chose to focus on technologies applicable to diurnal and cross-day storage, that can exceed an 8-hour discharge duration at rated power. We review technologies that are commercially viable or in the commercialization process. Lithium-ion storage represents a benchmark of "standard" battery technology, which is commonly used for short-duration storage.

Surveys were sent to companies identified as actively developing relevant technologies, asking for estimates of costs and performance metrics typical of a system marketed to customers. We also requested minimum and maximum deliverable sizes and the associated marginal costs. Companies agreed to meet and provide additional details through correspondence. These survey data were supplemented by a literature search that prioritized recent publications (2015 or later) to provide a more complete view of the current state of technologies and focused on real-world examples of operational projects rather than theoretical simulations, specifying current costs and performance rather than future projections. To be comprehensive in our data-capturing process, land footprint data of some projects (e.g., compressed air and concentrated solar) were estimated using Google Earth on locatable projects, ignoring underground infrastructure.

. To gauge the effectiveness of storage on the scale of days or weeks, we compute the equivalent efficiency, a value that considers both roundtrip efficiency and idle losses. Some companies also provided information about their reference systems which are either typical, nominal, or useful configurations in demonstrating their technologies. Based on the reference system, we calculate how the project average capital cost, evolves with different energy ratings for a power rating. To be comparable among different systems, we normalized the cost by dividing the four-hour system.

Results

Traditional LDES technologies, as represented by pumped hydropower storage and CAES, are characterized by their geographic limitations and environmental impacts.

Our figure (not able to shown through the submission system) highlights the land use footprint of multiple LDES technologies as a function of energy rating – ranging from several square meters to thousands square kilometers, depending on application and use, and compared with reference values in terms of area and energy needs in California.

Having smaller footprints for emerging technologies may inspire new business models (e.g., modular distributed storage) for long-duration energy storage to enter the market. For example, small TPV storage options such as those developed by Antora Energy are likely to support more flexible sizing and siting with smaller minimum footprints. Other storage options, such as small flow batteries could provide back-up power to commercial buildings or residences next to a single-car garage, enabling a distributive capability for this technology.

The siting location of storage technologies also varies depending on physical power plant infrastructure needed to complement installations. The smaller scale of thermal storage comparing with thermal power plants provide a potentially profitable retrofit option where carbon-intensive thermal generation that may be costly to operate can be phased-out by replacing silos and powering turbines with steam from particle thermal storage. These thermal technologies may offer relief to power plant owners who fear operating future stranded assets or could provide employment opportunities for workers trained in operating thermal power plants. Liquid-air energy storage can also utilize waste heat with a similar footprint. Liquid-air overcomes the geographic constraints of conventional compressed air technology, which needs underground caverns.

In addition to retrofits near power plants, tower gravity technology can also be deployed near demand centers as the manufacturing and operation is similar to building construction. A place the size of Union Square plaza in San Francisco (~10,000m^2) could hold a 70MWh Energy Vault project. The underwater PSH technology seems to fit the size of a farm pond but it has an additional requirement related to water depth. Yet, the modularity of underwater PSH adds flexibility in the location and installed capacity of new projects. For example, it is possible to deploy in larger water bodies such as Lake Tahoe, CA. When comparing technologies, as shown in Figure, one can also identify both the advantages for economies-of-scale with larger energy footprint plants such as PSH or advanced rail storage, and the disadvantages related to limitations in the available land-area for deployment.

The land footprint uniquely describes a less-commonly discussed aspect of the energy transition. Geographic requirements, especially in states or countries with limited land availability and protected natural and cultural territories, present constraints and opportunities for long-duration storage technologies. The co-location flexibility and modularity in arrangements could be an advantage for siting new projects and reducing overall system costs due to land, while simultaneously reducing area-related environmental and social impacts. Alternatively, the footprint graph also presents market entry opportunities at different scales in the power grid, whether in the distribution system, transmission system, or as a replacement/complement to existing generation.

(more results not shown due to text limitation)

Economics and the Potential Role of Expanding Geologic Energy Storage in the United States

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Abstract

U.S. energy production is undergoing a transition to increase the incorporation of renewable sources. The efficient utilization of the nation's evolving energy mix will require an expansion of energy storage. Currently, wind and solar power are being curtailed during periods of lower demand, which is a market failure that can lead to zero or even negative pricing of electricity. Expanding energy storage capacity could foster greater integration of renewable energy sources and reduce their curtailment (Kintner-Meyer et al., 2012; Palchak et al., 2017; Newbery, 2020). Geologic energy storage options include those for natural gas, hydrogen, compressed air, pumped hydroelectric, gravity and geothermal. Non-geology-based energy storage methods are mostly focused on a variety of battery technologies. Economic comparisons of these energy storage options could rely on the proportion of upfront sunk costs of investment to operating costs; performance measures, including rate and duration of discharge, number of cycles per year, expected downtime, and round-trip efficiency; and potentially some other characteristics, such as siting limitations, estimated risks, and dependence on supply of exceedingly scarce or costly critical minerals and materials (Mongird et al., 2019, 2020). The "Characterization of domestic subsurface energy storage resources" task of the "Utilization of Carbon and other Energy Gases—Geologic Research and Assessments" project (funded by the U.S. Geological Survey Energy Resources Program and based in the Geology, Energy & Minerals Science Center) was tasked to develop a white paper on the potential assessment of geologic energy storage resources in the United States, including a comparison of the costs and benefits of developing them. This is a presentation of some preliminary findings of the research for the economics section of that white paper.

Methods

The U.S. Geological Survey (USGS) has conducted resource evaluations for technically recoverable undiscovered hydrocarbons, for buoyant and residual geologic carbon dioxide (CO_2) sequestration, and for potential for undiscovered domestic and global deposits of minerals, amongst others. If approved, the assessment of geologic energy storage resources will endeavor to leverage data on depleted oil and gas fields that might become geologic energy storage targets, salt isopach maps and oil and gas assessment studies in the U.S. that could be repurposed to identify locations for salt-hosted energy storage caverns for gases such as compressed air or hydrogen, and previously developed geologic assessment methodologies. The economic analysis could involve adaptation of previously developed models and methods for evaluating the economics of basin-scale deployment of geologic CO_2 storage, the relative feasibility of CO_2 mineralization, and other USGS resource evaluations.

Results

For grid-scale deployment, currently available battery technologies could occupy a very large surface area, whereas geologic energy storage could require a relatively small surface footprint to provide the same energy storage capacity. However, there is greater flexibility in where even large battery arrays could be sited compared with geologic energy storage (where the site location will be constrained by the availability of amenable geologies). Geologic energy storage could be more economic than batteries for long-duration energy storage (beyond 6–10 hours), and it has the capacity to mitigate the impacts of seasonal fluctuations in energy supply and demand or extended shortages caused by severe weather or other unexpected events. However, if geologic energy storage is unused for long periods of time (awaiting an extreme but rare event) it could increase risk (of blowouts, other leakage, or induced seismicity), and there would be no flow of revenue to the energy storage operator. During these times, costly subsurface and surface monitoring and risk management protocols would have to be maintained, and an appropriate public financing arrangement could be necessary to maintain the geologic energy storage operation in a safe state of readiness. In order to directly provide a short-term infusion of electricity to support the grid, some forms of geologic energy storage could be more costly and require more ramp time than batteries while the energy (such as hydrogen or compressed air) is converted to the electricity demanded. Given a greater number of cycles over the project lifetime, geologic energy storage resources could have greater reusability and may not degrade as much or as rapidly as battery storage. Geologic energy storage sites require costly characterization of the subsurface, and the upfront costs of investment could be prohibitive. Mining and refining of critical minerals and raw materials could constrain expansion of battery storage. For grid-scale deployment, batteries can require large volumes of critical minerals that may need to be imported, and technologies and infrastructure to enable profitable recycling of these minerals and materials are still being developed and are not widely available.

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A methodology for evaluating the future value of utility-scale PV-plus-battery hybrid systems

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Abstract

Systems comprising solar photovoltaics (PV) coupled with lithium-ion battery storage, or PV-plus-battery hybrid systems, are of growing interest because of recent technology cost and performance improvements and state and federal policies. It is estimated that approximately 40 utility-scale PV-plus-battery projects were installed on the bulk power system before 2020, and over 25% of PV capacity in U.S. interconnection queues in 2020 was paired with battery systems. It is expected that more than half of all battery capacity in interconnection queues will be paired with PV by 2023. However, there is uncertainty around these systems' design and operations and how these aspects affect long-term deployment potential. Few electricity sector modeling tools currently include representations of PV-plus-battery systems, and those that do include only simple representations that do not reflect the range of possible configurations or are limited in their temporal resolution.

In this work, we develop a technoeconomic methodology for exploring how the value of PV-plus-battery hybrid systems could evolve over time and across locations through the combination of several existing electricity sector modeling tools with different temporal and geographic scales. We use this methodology to analyze and quantify the future operations and value of PV-plus-battery systems based on simulated electricity prices that reflect evolving grid conditions projected through 2050 using a capacity expansion model. We evaluate and compare the economic performance of PV, battery, and PV-plus-battery systems across many years and locations, with consideration of different architectures (i.e., how the PV and battery systems are coupled) and component sizes, including PV inverter loading ratio (ILR; i.e., the DC-to-AC ratio of the PV array to the inverter), battery power capacity, and storage duration. The goal of this work is to understand the factors that influence the performance and economics of various PV-plus-battery systems in order to evaluate the potential benefits of these hybrid resources to future power systems.

Methods

The methodology developed for our analysis is to use a price-taker optimization tool to dispatch PV-plus-battery hybrid systems against simulated future hourly electricity prices. These hourly prices come from a process that involves the (1) optimization of the generation and transmission buildout through 2050 using a capacity expansion model, (2) optimization of the hourly operations of the resulting bulk power system using a production cost model, and (3) processing of the resulting hourly data to create combined energy and capacity prices for future years.

The modeling tools we used to obtain price signals were the National Renewable Energy Laboratory's (NREL's) Regional Energy Deployment Systems (ReEDS) capacity expansion model and Energy Examplar's PLEXOS production cost model. The outputs of these tools can be found at the Cambium website (cambium.nrel.gov). Hourly PV generation profiles were obtained from NREL's System Advisor Model, a tool that uses location-specific weather and solar resource data to simulate PV system operation.

The hourly price and generation profiles were used as inputs to a price-taker tool to determine each PV-plus-battery system's revenue-maximizing dispatch—accounting for configuration-specific energy pathways and efficiencies—which ultimately determines the system's value to the bulk power system. The price-taker tool we used was the Revenue, Operations, and Device Optimization model. Our methodology can be applied to any location, depending on data availability, and different tools can be substituted into the workflow. For this analysis, we focused on locations in California, Texas, and New York.

The first part of our analysis compared the two PV-plus-battery system architectures that are commonly discussed in the literature: AC-coupled systems, in which the battery and PV components each have their own inverter, and DC-coupled systems, in which the battery and PV components share a single inverter. DC-coupled systems were further divided into loosely coupled systems, which can charge from either the coupled PV or the grid, and tightly coupled systems, which can charge from the coupled PV only. For this part, component sizes of each configuration were held constant, with a 77-MW_{AC} PV (AC-coupled) or bidirectional (DC-coupled) inverter, a 100-MW_{DC} PV array (for an ILR of 1.3), and a 60-MW_{AC} battery with four hours of storage.

In the second part of our analysis, we focused on loosely DC-coupled systems so that we could explore the interactions of the PV ILR and the batter-inverter capacity ratio (BIR), or the ratio of the battery power capacity to the inverter capacity. We compared configurations with ILRs from 1.4 to 2.6 in increments of 0.2 and with BIRs from 0.25 to 1.0 in increments of 0.25, for a total of 28 unique configurations in each location.

The value streams analyzed were energy value and capacity value, where the latter is the product of the capacity credit and the avoided cost of new capacity (the annualized cost of a new natural gas combustion turbine). For PV-plus-battery systems with available capital cost information, we determined the benefit-cost ratio. For systems without capital cost information, we determined marginal breakeven costs.

Results

In the first part of our analysis, we found that the highest-value PV-plus-battery architecture differs by region, depending on solar resource and the effect of grid conditions on electricity price patterns and magnitudes. AC-coupled systems provide higher value to the bulk power system when it is valuable to discharge the battery simultaneously with PV generation. Tightly coupled systems provide the lowest value because the battery cannot arbitrage between low- and high-price hours. However, as PV penetration increases, the different architectures converge in value: their capacity value converges to the battery's capacity value, and their energy value converges toward that of tightly DC-coupled systems. This convergence in value happens because a growing fraction of the coupled PV energy is sent to the battery instead of the grid.

In the second part of our analysis, we found that DC-coupled PV-plus-battery systems with higher ILRs will experience greater amounts of clipping due to both power limitations (i.e., the limited total power rating of the shared inverter and the battery) and energy limitations (i.e., the limited duration of the battery). Regardless of component sizing, curtailment increases in each location as shares of VRE generation grow in future years. Eliminating curtailment requires both longer duration storage and a battery power rating closer to that of the PV array so that the battery can absorb the full instantaneous output of the PV array in any given hour. However, eliminating all clipped and curtailed energy is not necessary for higher-ILR PV-plus-battery systems to be cost-effective. In a future with low-cost renewable energy technologies, ILRs could likely be economically increased to 2.0–2.4 at a BIR of 1.0, depending on solar resource (e.g., higher in areas with lower solar resource).

These results contribute to the growing body of literature demonstrating the synergies between PV and battery systems: battery storage mitigates the value decline of PV as the share of PV generation on the grid grows, and PV capacity provides the battery with energy at zero (or very low) marginal cost, displacing more expensive energy. It is likely that, in a future with higher shares of PV generation, PV-plus-battery systems will evolve toward increasingly higher BIRs to make up for declining PV capacity credit. In the case of DC-coupled systems, higher BIRs will enable increasingly higher ILRs to further increase net energy value. Similar trends are already occurring in locations (e.g., Hawaii and California) with relatively high shares of PV generation.

Transportation

Trade-offs between automation and light vehicle electrification

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Abstract

Weight, computing load, sensor load, and possibly higher drag may increase the energy use of automated electric vehicles (AEVs) relative to human-driven electric vehicles (EVs), although this increase may be offset by smoother driving. Here, we use a vehicle dynamics model to evaluate the trade-off between automation and EV range and battery longevity. We find that automation will likely reduce EV range by 5-10% for suburban driving and by 10-15% for city driving. The effect on range is strongly influenced by sensor drag for suburban driving and computing loads for city driving. The impact of automation on battery longevity is negligible. While some commentators have suggested that the power and energy requirements of automation mean that the first automated vehicles (AVs) will be gas-electric hybrids, our results suggest that this need not be the case if automakers can implement energy-efficient computing and aerodynamic sensor stacks.

Methods

We use a high fidelity vehicle dynamics model to determine the range of automated electric vehicles (AEVs). We do this by adding the weight of the different components to the mass of an electric vehicle (EV) and battery pack, increasing the drag coefficient for automated solutions with a roof-based spinning LiDAR. If no LiDAR is used, or if solid-state LiDAR that is incorporated into the aerodynamic profile of the vehicle is used, the increase in drag is zero. We also modify the velocity profile of the vehicle to account for potentially smoother driving and add the computing and sensor loads for the automation stack at each second. Keeping track of the total energy used, we repeat the driving profile until the battery is fully depleted. This gives us an estimate of the AEV range for a given battery capacity. We then compare this AEV range to the EV to understand how automation affects vehicle range. We run this simulation for two types of velocity profiles: the California Unified Cycle Driving Schedule which is a composite profile i.e. a city-highway mix, and the Urban Dynamometer Driving Schedule which is a city-only profile.

We also model the longevity of the battery for each type of vehicle; that is, to estimate the number of total miles for which the vehicle can be driven until the battery is unable to charge to more than 80% of its original capacity. To realistically assess battery degradation, we model a series of a 24-hour periods in each of which the vehicle drives for 50 miles for the composite profile (or 30 miles for the city profile), charges until the battery is full, and then rests until it is driven again the following day.

Results

We find that automation is likely to reduce EV range; and that the aerodynamic impact of LiDAR is a significant driver of this reduction in suburban driving, while computing loads have a greater effect for city driving. Across different EVs, we find a median reduction in the range of 3-5% for a suburban drive profile and no drag impacts from LiDAR. Including LiDAR increases the median range reduction to between 8-12%. A reduction in range will lead to more frequent charging speeding up battery degradation but we find that this impact on battery longevity is negligible.

A Systematic Review of GIS-Based Methods and Criteria Used for Electric Vehicle Charging Station Site Selection

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Abstract

A multitude of studies have incorporated particular models with various methods and algorithms to resolve the site selection problem for Electric Vehicle Charging Stations (EVCS). This paper systematically reviews research that evaluates Geographic Information Systems (GIS) based EVCS location techniques and the variables used for decision making. We classify and characterize those techniques and variables to determine important linkages within the literature. A variety of databases were referenced to extract research published from 2014 to 2021 pertinent to this specific location problem and 40 papers were selected after thorough evaluation. The models used in each paper were examined along with the methods for selecting variables and ranking alternate locations. Site selection for EVCS requires a Multi-Criteria Decision Making (MCDM) approach to meet the sustainability, efficiency, and performance goals of communities that are adopting EV technology. Our results indicate that map algebra and data overlay methods have been used more frequently with GIS-based analysis than other techniques, while geographic and demographic variables are commonly the most significant site selection factors. The reviewed methods have most often been applied to urban locations; however, the transfer of these techniques to a rural EVCS site selection problem has been rarely explored in the current literature. This

research assessment contributes relevant guidance for the application of methodologies useful in policy making, and provides recommendations for future research based on these findings.

Methods

Solutions for the EVCS site selection problem require the incorporation of data from an expansive array of sources and can be spatial or non-spatial, qualitative or quantitative in character, and discrete or hardly quantifiable. A tool that is well suited for analysis of a complex collection of data is the MCDM Method because it allows the consistent analysis of different quantitative and qualitative elements in a decision-making process. Holistic GIS aided MCDM methods for solving the multivariable location problem will benefit EVCS infrastructure expansion and utilization of EV transportation. This study systematically reviews literature on EV CS site selection methods that employ geospatial analysis through GIS software combined with various modeling schemes, criteria selection techniques, and location algorithms. The present study attempts to answer the following research questions.

1. How has the frequency of published articles specifically using GIS-based methods for EV CS site selection progressed over the time frame of 2014 to 2021?

2. Which MCDM models and methods are most frequently applied when undertaking GIS-based EV CS location selection research?

3. What variables are most frequently used as decision elements to resolve the EV CS site selection problem?

Results

Many GIS-based approaches to solving the EVCS location selection problem exist and each of the reviewed papers use a methodology that attempts to balance the interests of various stakeholders. These methods utilize variables that have been processed in order to optimize the type, size and location of EV CS infrastructure in a community, however, a prime difficulty in the site selection problem is that spatially detailed complex models can be temporally, computationally, and financially costly to solve. Due to the complexity of this problem a solution framework must use heuristic approaches, algorithms, and geospatial analysis collectively while limitations are considered.