Montreal Special Issue 2019

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IAEE Energy Forum

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Editor: David L. Williams

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INTERNATIONAL ASSOCIATION *for* ENERGY ECONOMICS

PRESIDENT'S MESSAGE

The 42nd IAEE International Conference has just concluded. It brought together energy economists from around the world in Montreal, Canada.

This country is composed of provinces which all bring to energy economists typical real scale case studies: all energies are represented, all configurations of energy markets, all profiles of consumers are present. Montreal was also in 2005 the place where the 11th session of COP on Climate Change happened. I would like to sincerely thank HEC Montreal for the organization of this event, and in particular Pierre-Olivier Pineau and Johanne Whitmore.

After recent international conferences in Perth, Daegu, New York, Antalya, Bergen, Singapore, Groningen and before Paris, Tokyo, Riyadh and Izmir, setting the international energy economics conference in Montreal was a real must!

I would like to thank the Prime Minister of Canada, Justin Trudeau, the Prime Minister of Québec, François Legault and the Mayor of Montréal, Valérie Plante for their high patronage.

Our Association, present in 110 countries, is willing to share the economic science with as many people as possible. As we have seen from yellow jacket demonstrations in Paris, our challenge is to disseminate academic knowledge more widely to the public because people do not always understand the rationality of political choices. We are ready to contribute to this. We are ready to support the transformations necessary for environmentally friendly economic development and to guarantee access to energy for all.

Oil, nuclear and renewable energy, electricity networks, new trends for residential and industrial consumers, energy and environmental policies, emerging technologies, commercialization of new services, energy poverty... All these areas of energy economics are major concerns for all world economies and were addressed in Montreal.

A pre-conference seminar was organized in Montreal on Equilibrium Methods for Analysis of Environmental Policy in the Power Sector. Students and other members had the opportunity to present their research during concurrent and poster sessions.

I am pleased to announce that Montreal conference proceedings and videos are now accessible on the IAEE website. I have decided to share our visions with the international community by using social media. I invite all of you visit #IAEE2019MTL hashtag on Twitter.

In Montreal it was a pleasure for me to present the Outstanding Contributions to IAEE Award to John Jimison. I also presented the Energy Journal Best Paper Award to Elbert Dijkgraaf, Tom P. van Dorp, and Emiel Maasland for their paper entitled: "On the Effectiveness of Feed-in Tariffs in the Development of Solar Photovoltaics". The Winner of the IAEE poster competition was Nicolas Thie with "Evaluating the Business Case For Flexibilities as Risk Management in Direct Marketing of Renewable Energies".

Just 50 years ago, two Americans, stepped on the moon. Beyond the sheer magnitude of this event, this mission allowed Humanity to see the Earth from space. Neil Armstrong compared the Earth to a lost oasis in the middle of a huge black

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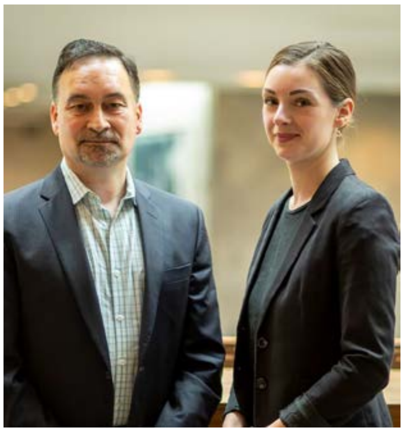
EDITOR'S NOTES

We would like to thank Pierre-Olivier Pineau and David Williams for providing us the opportunity to act as joint editors for this year's Energy Forum Special Issue. The Special Issue showcases a selection of papers presented at the 42nd IAEE International Conference held in Montreal, Canada from May 29 to June 1, 2019. As joint editors, our task was to select approximately 20 extended abstracts, based on papers to be presented at the conference, and to guide the authors through the publication process for this year's Special Issue. This was certainly a challenge, as there were nearly 500 quality papers from which to choose.

This year's Special Issue includes 17 articles from among the 262 papers presented at the conference. In selecting the articles, we tried to represent the diversity of issues that were discussed in the 60 concurrent sessions held over 3 days. We also tried to reflect the geographical dispersion of topics and authors participating at the conference. We were impressed by both the papers submitted and the broad international representation among attendees of the conference.

We invited the selected authors to write an extended abstract version of their papers, limited to approximately 1500 words, taking into account the space for tables and figures that might be included. We would like to thank all of the authors for their professionalism and cooperation in responding to our invitations, and for their efforts in preparing excellent extended abstracts for the Energy Forum Special Issue. We would also like to give special thanks to Olga Pushkash for guiding two rookie editors through the process.



We hope that Energy Forum readers will find the collection of articles in this issue as interesting and thought-provoking as we did. The articles appear in the order in which they were presented at the conference; the ordering does not in any way reflect a preference around the quality of the articles. There are many important and challenging issues that policy-makers and society are grappling with as we build towards an affordable and sustainable energy future. We believe these articles offer evidence that energy economists across the world have plenty to offer to the conversation.

Laura McLeod and Brian Rivard

President's Message (continued)

and hostile space. It encouraged the protection of our environment long before the debates on climate change demonstrated the urgency for action.

IAEE works in particular within its international conferences to promote economic rationality and in our field of competence, energy economics. This is what we will continue to do at the next IAEE International Conference on the theme: "Energy and Climate, Working Hand in Hand". Préparez cet évènement sur iaee2020paris.org et #IAEE2020PARIS.

Christophe Bonnery

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NEWSLETTER DISCLAIMER

Interview with Prof. Pierre-Olivier Pineau, General Conference Chair, 42nd IAEE International Conference

Mr. Pineau started attending IAEE conferences as a PhD student. Attendance to the conference was useful in order to show his work and interact with peers. IAEE was the best option, as it is the Association which allows us to share and discuss our work within Energy Economics. Mr. Pineau says that attending IAEE conferences was a career-changer. Once he became a professor, he continued to attend IAEE conferences where, progressively, he created a network of colleagues. This is how he came to be a Concurrent Sessions' chair for the New York City and Calgary conferences.

The 42nd IAEE International Conference project started four years ago. This would be the first time that the international IAEE conference would take place in Montreal, Canada. Mr. Pineau thought it would be an interesting and rewarding project, and accepted the offer to chair this conference. Having enjoyed many IAEE conferences as a delegate, he thought this would be a nice way to give back to the IAEE community.

Additionally, he felt that it would be valuable to bring the energy economics community to Canada, as he feels that Canada deserves a place in the international debate.

The title of this year's conference was, "Local Energy, Global Markets" and the goal was to emphasize the need to bring energy to markets. Energy by definition is starting from a local place and it is not easy to bring it to global markets. There are many needs when you look at the largest consumers of energy in the world, who are very often not producing energy locally. With renewable energy, the problem becomes even bigger because the renewable energy sites are not close to the consumption sites. Therefore, you need to interconnect markets efficiently. The academic goal of the conference in general is to have a deeper discussion on these topics. Additionally, the aim is to create a meeting place for people to create networks, especially for young researchers to meet more senior researchers, and to get advice and inspiration. There are not many international conferences where you have more than 40 countries represented; therefore, the IAEE conference has immense value.

Being a General Conference Chair for this type of conference carries many responsibilities. Finding sponsors and organizing the academic program are two of the biggest challenges. Additionally, managing logistics around the conference is complex and time consuming. Mr. Pineau emphasizes that a calm demeanor and strong organizational skills are the keys to a successful conference. It is important not to delay things and to work constantly on the project. Communication is also very important; a good website is important to provide delegates with the necessary information. Being grateful for all the support that we receive for the conference must also be mentioned. All contributors, including sponsors and the organizational team, should be proud.

One of Mr. Pineau's key pieces of advice for future organizers is to find the right team. He mentions that if the team is too small, then you cannot deliver on the project. If the team is too big, then coordination becomes a challenge. Only the right equilibrium will lead to success. In any case, there will be challenges related to communication or coordination, which is why it is so important to stay calm and be solution-oriented.

Mr. Pineau's favourite moment of each conference comes with seeing the smiling faces of the attendees. This conference represents a great deal of hard work for the whole team. He loves to hear that delegates had an insightful conference and that they are leaving with new ideas and projects to work on.

Montreal Conference Overview

The 42nd IAEE2019 International Conference was organized by HEC Montreal (Chair in Energy Sector Management), GERAD and CAEE (Canadian Association for Energy Economics). The conference was held at HEC Montreal on May 29 – June 1, 2019.

431 delegates attended the conference, academic presentations were scheduled within 57 Concurrent sessions and 17 poster sessions. Additionally, eight dual plenary and two plenary sessions were organized.

On Wednesday 29 May conference delegates were invited at the Delta hotel in Montreal for the opening reception. The conference gala dinner was held on Thursday 30 may at the Old Port of Montreal. It is an historic part of the city, with spectacular views over Saint Lawrence River and the city itself. During the dinner several distinguished awards were given. This Special Issue of the Energy Forum is featuring interviews with the awards winners.

Interview with Christophe Bonnery, IAEE President

President Bonnery has been a member of the IAEE for more than 30 years. In 2010 Mr. Bonnery was elected as President of the French IAEE chapter – FAEE. After several years of service for the Association, Mr. Bonnery was elected in 2018 by the IAEE's members as a President-elect. In 2019 he became IAEE`s President.

Could you mention the aspects which inspires and motivates you for your work within the Association?

In the field of energy policy, the Association is a place where open-mindedness and collaborative building is a raison d'être, a mainspring. Researches are inspired solely by economic rationality applied to energy. By design, our publications and conferences discard partisan approaches and unproven assertions. Our scientific journals thanks to the peer review processes and our conferences thanks to the plurality of speakers guarantee the quality, the relevance and the interest for our results. What inspires and motivates me is the ardent desire to contribute to this excellence and to share it with as many people as possible.

You have been within the Association for many years. Please tell our readers about how the Association changed over the past years.

The excellence of our association comes from the accumulation of academic knowledge. What has changed over time is the volume of research that has increased over time, along with the number of our members. We account more than 3700 members. What has changed is the geographical scope; we are now represented in more than 110 countries. What has also changed are the transverse research themes: the focus is less on oil and gas and more on electricity.

To accompany these changes, IAEE has created more publications: after *The Energy Journal*, we created the *Economics of Energy & Environmental Policy* and to address current issues, *The Energy Forum.*

In our last year's interview during Groningen Conference you mentioned that you were working hard on IAEE`s geographic development and strategic actions. Could you mention a few actions which were done since June 2018?

Beyond the expansion of IAEE's global presence through its members, I am proud to announce the imminent creation of new IAEE representations around the world:

After Bangladesh and South Africa, where I will speak for the second time in mid-November 2019, we are about to open representations in Azerbaijan, Kazakhstan and Romania. We are multiplying conferences in strategic countries such as Abu Dhabi. Finally, I am very committed to the creation of our representation in India, which we hope to be able to launch in December 2019. The energy challenges of the sub-continent are enormous and fully justify IAEE's presence. I would like to thank the IAEE teams who have made this progress possible in such a short period of time.

From your perspective which are the future challenges and goals for the IAEE?

As I have already said, IAEE offers first-rate research quality, relevance in many geographies and for many stakeholders: governments, decision-makers, investors, industrialists, consumers, etc....

The challenge I am seeking to meet is to further open the world of research by developing more means of communication that act directly and provide abundant and high-quality information. Therefore, I have decided to implement, with the support of our new Vice President Communication, Jean-Michel Glachant and his team, a new and proactive policy on social networks - Tweeter, Facebook, LinkedIn, Instagram. These tools will also allow us to retain student members who are receptive to new technologies. Social networks bring information in "Push" mode to professionals who have little time to keep up with the latest findings in energy economics and appreciate this time-making assistance.

Social networks are not only a tool for disseminating knowledge, they also reflect a sharing and exchange approach that is the raison d'être of our association.

These new services are starting. I invite each of our members to use them. For exemple on Twitter, join @IA4EE.

Last year you mentioned that the definition of the energy transition was one of the goals for 2019. Do you think that this goal was achieved?

Sadly, it seems not. This has even worsened and makes IAEE's mission even more important. The definition of the "energy transition" concept varies from country to country. As I often say in my various speeches at IAEE international conferences, each country has its own vision of its energy future. I have been able to discuss this with some energy ministers or decision-makers in different countries. These visions are different because the country's history, its natural and intellectual resources are unique to it. That's normal. But the aspirations of the leaders in the different countries give each energy policy different priorities: fight against climate change, energy access, fight energy poverty, ban nuclear power, support renewable energies, development of shale gas, etc... The various countries where we are represented aim for economic and environmental optimization. But these are often local optimums. The overall optimum may be different. Since there is no invisible global political hand, when everyone is debating and implementing the best 'energy transition', it would be good from time to time to wonder about the global optimum.

To this end, IAEE's informative, sharing and exchange role makes sense and must be strengthened.

Would you like to add anything else?

Join the IAEE, remain in the IAEE, participate in the IAEE

Quantifying the Benefits of Imperfect Demand Response

BY PATRICIA LEVI

Patricia Levi is a PhD Candidate at Stanford University. E-mail: pajalevi@gmail.com

Introduction

There are great expectations for demand response (DR), which encompasses the idea of an electricity consumer reducing or shifting their load in response to signals that are linked to market or operational conditions. The greater flexibility that DR could provide could be very valuable on a low-carbon grid. DR could help integrate intermittent renewables and help utilities meet resource adequacy requirements, which will be harder as the share of generation from variable renewables increases [1].

To realize the potential value of DR to a decarbonizing grid, we must understand how its properties affect its system-wide value. DR resources have different limitations from traditional generators in that they must respect the preferences of the customers whose load is being reduced or shifted. Customers have a limited appetite to shed or shift their load and may need advance notice to do so. This study examines DR that has different properties that may reflect customer preferences. Other studies have looked at one or a few of these properties, but in this study we compare many properties in the same modeling framework, so that we can identify their relative importance.

We identify the properties that result in more valuable DR, which may help guide investors and entrepreneurs in developing new products. This information can also help identify the properties of DR that wholesale markets should explicitly represent to encourage the best balance of system-wide value and consumer limitations.

Methods

A unit commitment model, based on [2], is used to simulate the ERCOT electricity system. This model represents ramping constraints, startup costs, and minimum load values for each generator. It simulates day-ahead and real-time decisions through two-stage stochastic optimization. Uncertainty comes from the demand forecast; commitment and production decisions made in the day-ahead stage are the same for all realizations of demand, while those made in the real-time stage are made uniquely for each demand realization. Slow generators have day-ahead commitment, while fast generators have real-time commitment; both have real-time production decisions.

We assume a total of 1000 MW of DR is made available in the form of many homogeneous smaller resources, which we model together as a single 'pseudo-generator' with a relaxed binary commitment variable, an optimistic marginal cost of $35/MWh, and a minimum load of 1 MW to impose a small commitment cost. This study only considers load reduction from DR, not load shifting.

We compare several limited versions of DR to 'perfect' DR resources that would be available all the time with no advance notification required. The modeled DR is subject to five different types of limitations: (1) number of startups, (2) number of hours of operation, (3) amount of energy shed, (4) which hours DR is available to be dispatched, and finally (5) how far in advance DR providers must be given notice for commitment and production decisions. There are two advance notice options: advance commitment (AC) in which commitment decision are made in the day-ahead stage, or advance production (AP) in which both commitment and production decisions are made in the day-ahead stage.

Results

Value of advance notification limited DR

Over the ranges modeled, both types of advance notification limits have a similar impact to usage restrictions on system-wide cost reduction (Table 1). The cost reduction per MWh shed is also in a similar range. These results indicate that advance notification limits and usage limits can be valued similarly by DR developers.

The benefits of AC DR come at the cost of being committed in more than twice the number of hours, due to the low cost of commitment. These operational characteristics indicate the need for other usage restrictions, or a higher commitment cost, if customers cannot tolerate this level of commitment.

A few hours provide the most value

As shown in Table 1, the marginal value of DR drops off as it is used more. DR provides the most value during a small number of peak hours and the associated steep ramps. As a result, DR that is unavailable during these key hours has a dramatically lower value. For example, summertime peaks in Texas often begin before 3pm, so DR that is restricted to the hours of 3pm - 9pm, when some consumers may be home after school or work, is notably less valuable than unrestricted or daytime-only DR.

Under typical structures for DR, a utility may wish to focus on DR that only operates during a small number of hours with the highest value. This is because DR customers typically are compensated twice for reducing their load: once through the incentive in their DR program, and again through a reduction in the amount of electricity they purchase. If we assume that retail customers are paying the average energy cost as their tariff, approximately $43/MWh in the modeled system, then all of the modeled DR programs would result in a net loss for the utility, although they reduce operating costs. DR that is only operated during an extremely limited set of very valuable hours mitigates this issue for now.

Startup limits alone cannot represent customer preferences

Startup restrictions are, in theory, a practical way of implementing a restriction on the number of unique 'events' that a DR resource experiences. However, in practice they do not work well in the absence of other restrictions. Startup limits can be met by simply never 'shutting down' DR as their modeled commitment cost is low. Consequently, when we restrict the modeled DR to only one startup per 5-day period, DR sheds slightly more MWh than unlimited DR but is committed in five times the number of hours.

Additional restrictions like a no-load cost or a response-duration constraint are needed for a startup restriction to create a desired number of unique 'events'. A higher commitment cost would help but remain imperfect. However, startup-based limits should be avoided for resources with low commitment costs and potential for customer fatigue from over-use.

Energy- or hour-based limits may be a more effective alternative for representing consumers' limited desire to shed load. The two have similar effects in this model, though future work should explore if this result holds when DR has a true binary commitment variable, as this variable is used for the hour-based limit.

Conclusion

These results inform a discussion about what types of 'imperfect' DR are preferable, a question that developers of demand response programs must address, given that consumers' preferences regarding how much load they will shed must be represented. Given our results, we suggest that developers of DR should be able to balance system needs with customer preferences better if they can focus on an hour- or energy-based limit to the usage of DR, rather than a startup-based limit.

These results suggest that entrepreneurs and developers of DR should pursue DR that has advance notification limits just as much as they pursue other usage-limited types of DR, and that system operators should enable such resources to participate in markets. More types of customers may be able to provide DR with advance notification, especially those without automation. To take advantage of the full range of cost-effective DR, the industry should identify ways to incentivize DR without compensating participants twice.

There are other types of DR characteristics that should be studied, like how reliably it responds to dispatch, how long it can shed load for, and sensitivity to marginal cost. Combinations of characteristics might represent known DR resources. Improved understanding of this nascent resource will enable the electric industry to take the best advantage of demand flexibility, which could enable integration of renewables and lower environmental impacts.

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[2] U.S. Department of Energy. *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them*. Tech. rep. U.S. Department of Energy, 2006. URL: https://eetd.lbl.gov/sites/all/files/publications/report-lbnl-1252d.pdf.

Scenario	Cost Savings from adding DR	Cost Reduction Per MWh Shed	Total MWh Shed
Advance Production	0.1531%	$ 8.85	415,404
1 Startup	0.1727%	$ 12.78	324,807
Advance Commitment	0.1730%	$ 12.84	323,714
5 Startups	0.1730%	$ 12.85	323,463
Unrestricted	0.1730%	$ 12.85	323,454
7a-10p Availability	0.1730%	$ 12.86	323,376
3 Startups + 30 Hour Limit	0.1612%	$ 15.60	248,318
3p-9p Availability	0.1129%	$ 13.02	208,378
Energy Limit (10 GWH)	0.1408%	$ 21.71	155,808
Hour Limit (10)	0.1407%	$ 21.75	155,381
Energy Limit (5GWH)	0.1096%	$ 32.33	81,429
Hour Limit (5)	0.1343%	$ 39.64	81,427

Table 1. Key statistics for modeled types of DR.
Scenarios are sorted by descending amount of MWh shed by the DR resource. Startup, energy, and hour limits are applied over a 5-day period. Hour limits refer to the number of hours in which DR is producing.

Market Design and Investment in Flexible Generation

BY BERT WILLEMS

A low carbon energy system will require sufficient flexible energy resources such as storage, flexible conventional generation and demand response. In an ideal competitive electricity market, market processes will guarantee that those resources are available: Short-run spot market prices become more volatile, which provides firms the correct incentives to invest in flexible energy resources. Electricity markets are however not perfectly competitive. In this project we look at one deviation from the ideal market model: the presence of start-up costs. Those are the additional cost that are incurred during the start-up phase of power plants, which could take several hours for some larger plants. Start-up costs are problematic because they make production costs non-convex. This implies that market equilibria, in which firms make investment and production decision on the basis of market prices, are no longer Pareto efficient. The standard welfare theorems no longer hold.

In practice, markets deal with start-up costs in different ways. In this project we compare two stylized market designs: a European-style power exchange and a North American-style power pool and derive bidding and investment decisions. (See Figure 1).

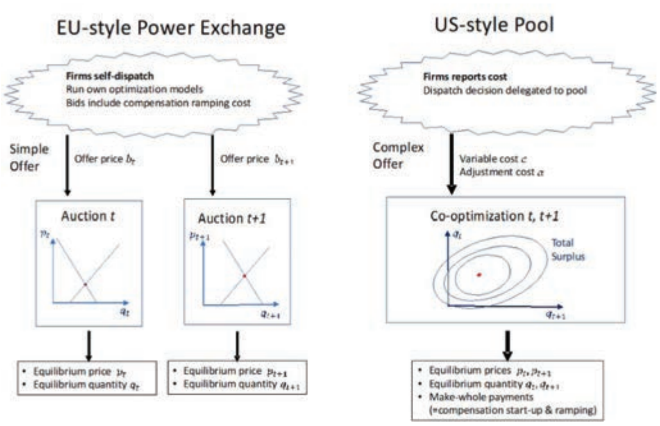

Figure 1: Market Design in a EU-style power exchange (left) and US-style pool operation (right).

In Europe, energy firms offer bids into separate hourly power markets. The auctioneer collects the bids for a particular period, clears the market and determines the equilibrium price. Bids are relatively simple: a bid indicates the willingness to supply electricity at a particular price and is not plant specific. Firms are responsible for scheduling their own power plants, taking into account start-up costs and ramping constraints. Hence, those ramping costs and start-up costs need to be internalized in the price bids.

In most North American markets, firms submit complex bids into a power pool. Those bids are plant specific, and represent the plant's operational characteristics: not only its production costs, but also ramping constraints, minimal production levels, and start-up costs. Those complex bids are collected by the auctioneer who optimizes total market surplus for all operating hours, taking into account all plant characteristics. The optimization model provides production decisions, energy prices and side-payments. Those side-payments are lump-sum payments to firms, to compensate generators for start-up costs. (For an overview on how side-payments can be determined see Liberopoulos & Andrianesis, 2016)

Bert Willems, is an Associate Professor of Economics at Tilburg University, Netherlands, and Research Associate at Toulouse School of Economics. Email: willems.bert@gmail.com

Hence, Europe relies on a simple market model, which requires firms to internalize start-up costs in their bids, whereas North-America relies on a more complex market model, in which firms are directly compensated for incurred start-up costs. We are interested how this different treatment of start-up costs affects investment incentives.

We extend the standard optimal investment portfolio model (See for instance Crew et al., 1995) and introduce start-up costs. It is assumed that firms can invest in a continuum of production technologies that vary from base-load to peak technology (similar to Zöttl, 2010). Each technology is characterized by its marginal cost cc, capital cost $k(c)k(c)$ and start-up cost $\alpha\alpha$. As in the standard portfolio model, firms are risk neutral price-takers, and there are no-entry barriers. Demand is price responsive and stochastic. Intra-day demand variation is represented by two representative hours. In the spot market, firms submit bids before demand is realized.

Market outcome

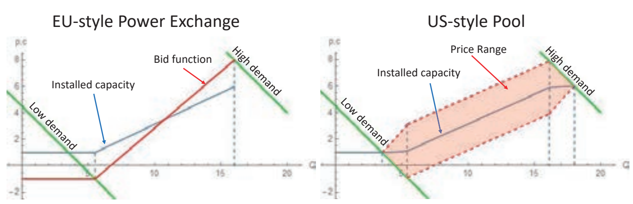

Figure 2: Installed capacity (blue) and possible equilibrium prices (red) for EU-style power exchange (Left) and US-style pool (right). The area in red indicates the set of feasible prices. We assume additive, uncorrelated, and uniformly distributed price shocks.

Figure 2 represents results under both market designs for a particular set of parameters. In an EU-style market design (Figure 2, left) competitive bidders submit offers that differ from their marginal cost (blue). Baseload companies offer below costs as they are likely to be producing in subsequent time periods. Hence they try to avoid incurring start-up costs by bidding low. Peakers offer bids above their costs, as they are unlikely to be producing in subsequent time periods. By bidding higher they are guaranteed to receive a compensation for their start-up costs. The blue line represents the equilibrium portfolio, the industry merit order curve. Investment decisions are such that all technologies make zero profit. In a US-style market design (Figure 2, right), firms bid their marginal cost c and the adjustment cost α. Equilibrium prices are determined by the auctioneer and depend on the realized demand shocks for both periods. Prices can be above or below the marginal costs c, depending on the particular combination of shocks. As we have a continuum of small firms in our model side-payments do not arise in equilibrium. Hence, the US-style market design is Pareto efficient. The investment portfolio (blue) corresponds to the free entry equilibrium.

Conclusion

Our initial simulations indicate that the US-style market design leads to efficient short-term operation and optimal investments. The EU-style market design has inefficient short run operation as it lacks coordination of scheduling decisions. This distorts investment levels: Too little is invested in peakers and too much in baseload. In practice the European market design is not as bad as modeled here. Some co-optimization already takes place as firms can submit block bids which cover multiple time periods at once (Meeus et al. 2009); demand shocks are correlated, which reduce coordination failures; and spot markets clear in multiple rounds, which allows firms to learn about market prices. The European market design might also provide larger incentives to invest in lower start-up costs, which in combination with fewer gaming opportunities, might shift the balance in favor of the European market design.

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Opening Plenary Session: Mark Jaccard - Estimating Efficiency vs Political Acceptability Trade-off for Deep Decarbonization

SUMMARIZED BY TIM SCHITTEKATTE, RESEARCH ASSOCIATE, FLORENCE SCHOOL OF REGULATION

Due to a delay of his morning flight, Christopher Knittel had to be replaced last minute as the keynote speaker. Mark Jaccard, was appointed to take his place. Jaccard assured that his sister, working for Air Canada, had nothing to do with the unforeseen swap.

It's economics, stupid! Or not only?

Jaccard started his talk by pointing out carbon pricing has become a mantra for economists since decades. However, for politicians who need to be reelected, it's a different game. This is best illustrated by the fact that, except for experimentation in a limited amount of states, carbon pricing has not been implemented in the US. In the meantime, GHG emissions have been rising year after year.

Should economists ignore evidence of humanity's failure on climate and just blame the politicians? Or should they incorporate the likelihood of implementation of a policy and try to make these alternative policies better? Jaccard opts for the latter by advocating that the most effective policy is not necessarily the most efficient; to gain political acceptability for deep carbonization it helps to implement a myriad of policies. Carbon pricing can be important but as much are so-called 'flex-regs'. Examples of success stories where rapid GHG reduction has occurred with the aid of 'flex-regs' are Brazil (fuel standards), Sweden (buildings standards) and Norway (electric vehicles tax cuts). Yes, the 'implicit' carbon price of such alternatives might look high, but at least they make it through the political decision-making process.

Finally, Jaccard called out to all economists in the room. He urged them to help politicians with mission impossible by admitting that flex-regs and other mechanisms can play a major role. Economists should apply their creativity to make these regulations better, instead solely pointing out their flaws and promoting carbon pricing.

The Efficiency and Distributional Effects of Alternative Residential Electricity Rate Designs

BY SCOTT P. BURGER, CHRISTOPHER R. KNITTEL, IGNACIO J. PÉREZ-ARRIAGA, IAN SCHNEIDER, FREDERIK VOM SCHEIDT

Residential electricity tariffs typically distort - and thus do not allow consumers to respond to - the marginal cost of energy consumption. Rates are typically constant across time and location, despite the fact that short-run marginal costs can vary dramatically. As of the end of 2016, less than one quarter of one percent of residential customers in the U.S. faced electricity prices that reflected the real-time marginal cost of energy production. Furthermore, the bulk of system costs are recovered through volumetric charges - that is, charges per-unit of energy consumed - despite the fact that a substantial fraction of these costs are fixed in the short term. More economically efficient rate designs - enabled in part by the proliferation of smart metering infrastructure - could substantially improve market efficiency. However, the potential distributional impacts across customer types and incomes of transitioning from today's tariffs to more efficient designs have historically impeded progress.

This paper examines the distributional and economical efficiency implications of residential electricity tariffs. Using interval metering data - measuring electricity consumption every 30 minutes -for more than 100,000 customers in the Chicago, Illinois area, we assess the economic benefits of efficient tariffs relative to alternative tariff designs. The rate designs explored are depicted in Figure 1. We then use census data to understand the demographics - i.e. income levels - of the customers in our sample. A regulator might seek to shift from the current tariff structure to a two-part tariff, because the two-part tariff has higher economic efficiency. If this two-part tariff has an equal fixed charge for all customers, we demonstrate that this shift is regressive; the change in monthly bills is larger, as a share of income, for lower income consumers. However, we show that a two-part tariff that bases the fixed charge on income or other measures that correlate strongly with income can improve distributional

Scott P. Burger is a Research Associate and MIT Energy Fellow at the Massachusetts Institute of Technology in Cambridge, MA (sburger@mit.edu) **Christopher R. Knittel** is the George P. Shultz Professor and a Professor of Applied Economics at the MIT Sloan School of Management; **Ignacio J. Pérez-Arriaga** is a Visiting Professor at the MIT Sloan School of Management, a Professor and Director of the BP Chair on Sustainable Development at Comillas University in Madrid, Spain, and the Director of Energy Training at the Florence School of Regulation in Florence, Italy; **Ian Schneider** is a Research Associate at the Massachusetts Institute of Technology; and **Frederik vom Scheidt** is a PhD Candidate at the Institute of Information Systems and Marketing at the Karlsruhe Institute of Technology.

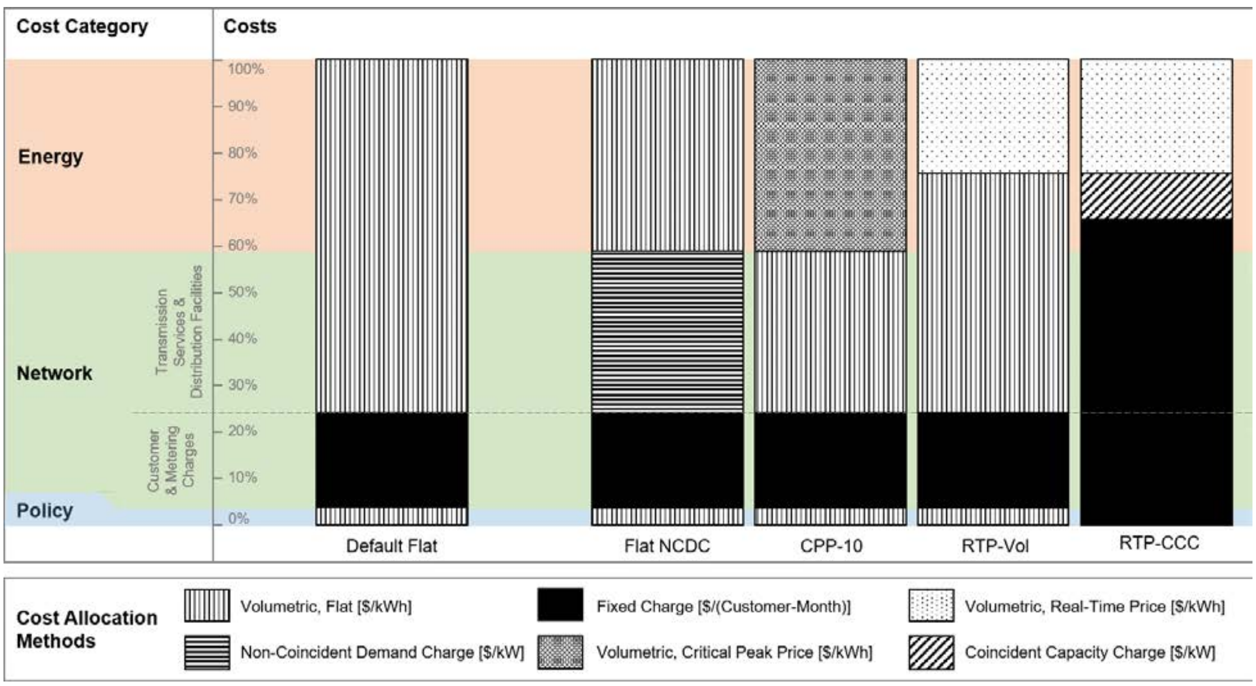

Figure 1: Breakdown of costs under the tariff designs in this study

outcomes without substantially sacrificing economic efficiency.

The issues addressed in this paper are likely to increase in importance as distributed energy resources (DERs), such as rooftop solar, become more prevalent. When located and operated appropriately, DERs can deliver substantial benefits. However, if investment and operation decisions are not aligned with system objectives, DERs can substantially increase system costs. The lack of spatial variation in retail prices distorts where DERs are placed within a network and how they are operated. In addition, remunerating transmission and distribution costs through volumetric charges over-incentivizes solar adoption by driving a wedge between the private and social returns to solar adoption. Adopters of some DERs, for example, rooftop solar, are able to reduce, or eliminate, their payments for transmission, distribution, and other regulated costs, despite the fact that these DER owners remain connected to and continue to use the network. Given utility revenue sufficiency constraints, this leads to increases in the transmission and distribution volumetric charges faced by other customers.

This can also have large distributional consequences. Because solar adoption tends to be positively correlated with income, high-income consumers are effectively passing on their contributions to transmission and distribution costs to lower-income consumers. Finally, widespread adoption of renewables can lead to larger diurnal price swings, exacerbating the difference between time invariant rates and the social marginal cost of consumption.

These converging challenges have led many regulators, policy makers, consumer advocates, and utilities to call for improved tariff designs. For example, the New York Department of Public Service recently called for “more precise price signals...that will, over time, convey increasingly granular system value.” New York is not an anomaly. In 2017, regulators in 45 of 50 U.S. states and the District of Columbia opened dockets related to tariff design or made changes to tariff design. Similarly, in November 2016, the European Commission issued a sweeping set of rulings, with tariff design as a centerpiece.

The economic pressure to redesign electricity rates is countered in part by concerns among policy makers and regulators of how more efficient rate structures might impact different socio-economic groups in terms of both average bills and bill volatility. For example, the Massachusetts Department of Public Utilities, the New York Department of Public Service, and the California Public Utilities Commission all list concerns about the distributional impacts of rates in their principles for rate design. Distributional concerns are not unfounded. For example, the U.S. Energy Information Administration recently found that 31% of U.S. households struggled to pay the costs of meeting energy needs. In practice, regulatory decisions highlight these concerns: in the U.S. in the second quarter of 2018, state electricity regulators rejected over 80% of utility requests to increase fixed charges, frequently citing the potential impacts on low-income customers.

Our work leads us to a number of novel findings. First, we find that, holding the proportion of fixed and volumetric charges in the tariff constant, annual electricity expenditures tend to decrease for low-income customers from movements towards more time-varying rates. However, increases in customer fixed charges tend to increase expenditures for low-income customers who, on average, consume less electricity than their more affluent counterparts. The net effect of a rate design with real-time energy prices and uniform fixed charges for residual cost recovery is a near monotonic negative relationship between income and changes in expenditures. Second, in our sample, the economic distortions of recovering residual network and policy costs through volumetric tariffs likely outweigh the distortions that emerge from charging an energy price that does not reflect the underlying time- and location-varying cost of energy. Finally, we find that changes to fixed charge designs can preserve the efficiency gains of transitioning to efficient residual cost recovery while mitigating undesirable distributional impacts. We highlight three methods for designing fixed-charges for residual cost recovery - based on customer demand characteristics, income, or geography - that mitigate the regressiveness of fixed charges. Figure 2 shows the difference in distributional impact between a uniform fixed charge and one based on a customer’s historical peak demand.

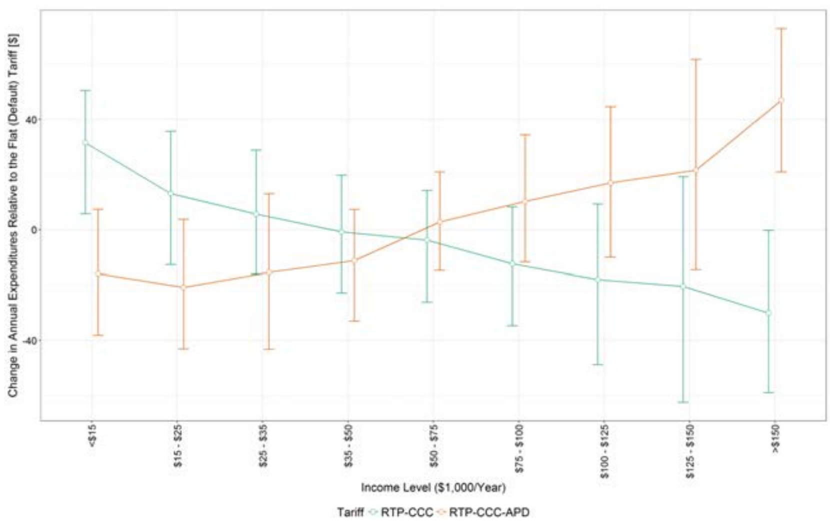

Figure 2: Change in annual expenditures under the RTP-CCC and the RTP-CCC-APD tariffs, zero-elasticity case

Duct-taping the U.S.'s Last Energy-Only Market: ERCOT

BY JAY ZARNIKAU, CHI-KEUNG WOO, SHUANGSHUANG ZHU AND CHEN-HAO TSAI

Economists have long debated whether market prices set at short-run marginal costs will generate sufficient long-term revenues to provide a reasonable return to existing suppliers and sufficient incentive to attract new investment in a capital intensive industry with high fixed costs. Affirming DuPuis (1844) and Hotelling (1938), Joskow (2013) concluded there is a 'missing money' problem in restructured electricity markets. Yet, not everyone is convinced that a capacity market, a resource adequacy requirement or some other administrative intervention is necessary to maintain a competitive and reliable electricity market in the long run (e.g., Kielsing and Kleit, 2009; Biggar and Hesamzaden, 2014).

Like other regions in North America, the Electric Reliability Council of Texas (ERCOT) has recently experienced low wholesale market prices, chiefly due to the low natural gas prices caused by the explosive growth in shale gas supply. These low wholesale market prices have rendered the continued operation of many coal plants in Texas uneconomical. Three large coal plants retired in early 2018, another coal plant may shutter before the summer of 2019, and a further coal plant is scheduled to retire in 2020. Further, the state's renewable energy development has reduced wholesale market prices via the merit order effect (Zarnikau et al. 2019). The coal plant closures and renewable energy's continued expansion, along with renewable energy production's negative correlation with load, underscore Texas's problem of low reserve margin projected in the next few years.

Until recently, the ERCOT market relied solely on market forces to retain existing generating plants and incent investment in new plants to ensure long-term reliability. In June 2014, however, it introduced an operating reserve demand curve (ORDC) to raise wholesale prices during times of capacity scarcity (Hogan, 2013).

Fig. 1 shows that the ORDC price adder is administratively set at the value of loss of load (VOLL) of $9,000/MWh when ERCOT's operating reserves are less than the minimum level of 2,000 MW. At levels of reserves above 2,000 MW, it is the VOLL times the loss-of-load probability (LOLP) of a system emergency within one hour. It declines to $0/MWh as ERCOT's operating reserves increase to ~5,000 MW, reflecting the LOLP estimate's rapid shrinkage to zero.

The ORDC has a limited impact on wholesale electricity prices when ERCOT's capacity scarcity is moderate. In 2016, for example, its price adder represented about 1% of the total price of energy paid by a consumer of wholesale energy in the ERCOT market.

Facing the prospect of a 7.4% reserve margin in the summer of 2019 and continued low planning reserves in subsequent years, the Public Utility Commission of Texas (PUCT) approved changes to ERCOT's ORDC in January 2019, so as to raise wholesale prices during periods of low operating reserves (Walker, 2019). The PUCT concluded that the economically-optimal or market equilibrium levels of generating capacity under ERCOT's energy-only market structure were too low from a policy and economic development perspective[1]. In January 2019, the PUCT approved shifting the ORDC based on the standard deviation (SD) of the hour-ahead operating reserve forecast error's distribution. The initial shift in 2019 is based on 0.25 SD and the second shift in 2020 0.50 SD. Figure 1 portrays that the approved shifts greatly magnify the ORDC price adder at levels of operating reserves above 2,000 MW.

Jay Zarnikau teaches in the departments of Economics and Statistics at the University of Texas and is a Vice President at Frontier Energy (jayv@utexas.edu); **Chi-Keung Woo** is Professor of Asian and Policy Studies at The Education University of Hong Kong (chiwoo@eduhk.hk); **Shuangshuang Zhu** is a Senior Program Consultant at Frontier Energy in Austin, Texas (zsslucy@frontierenergy.com) and **Chen-Hao Tsai** is a Senior Policy Studies Planner at the Midcontinent Independent System Operator(ctasi@misoenergy,org)'

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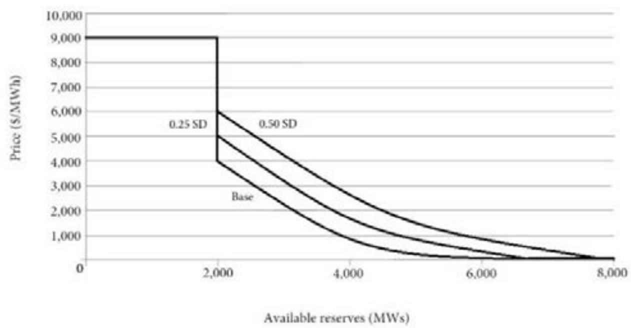

Figure 1. Price effects of the PUCT's approved shifts

A backcast of the ORDC price adders in the 4-year period of 2015-2018 indicates that shifting the ORDC would have greatly increased ORDC collections in 2018. Table 1 shows that the total electricity cost in 2018 was $14.24 billion at the recorded real-time prices, of which $0.75 billion was due to the ORDC. The 0.25 SD shift would have increased total ORDC collections to $2.11 billion, a $1.36 billion or 180% increase from the actual ORDC payment. This would represent a 9.5% increase in total electricity cost for 2018. The 0.5 SD shift would have increased the total ORDC collection to $3.25 billion, a $2.5 billion or 332% increase from the actual ORDC collection. However, the ORDC shifts' impact in

	2015	2016	2017	2018
Actual energy cost	9.63	8.91	9.55	14.24
Actual ORDC payment	0.49	0.10	0.09	0.75
Energy cost based on a 0.25 SD shift	10.14	9.13	9.76	15.59
ORDC payment based on a 0.25 SD shift	1.00	0.32	0.29	2.11
Energy cost based on a 0.50 SD shift	10.71	9.35	9.96	16.74
ORDC payment based on a 0.50 SD shift	1.57	0.55	0.5	3.25

Table 1. Backcast of annual energy cost and ORDC payment ($Billion)

the other three years would have been far smaller.

We use Table 1 to answer the policy question: could a shift in the ORDC ensure Texas's resource adequacy? Had the redesigned curves been in effect in 2018, it might have indeed been effective in delaying some coal plant closures and attracting additional investment in generating capacity. The same cannot be said about the other three years. Further, Table 1 indicates very large year-to-year variation in ORDC payments, presaging that the ORDC's impact over the next couple of years of slim planning reserves could be even greater than those backcasted for 2018. Such highly volatile ORDC impacts will continue to make generation investments in the ERCOT market quite a gamble.

To conclude, we concur with the PUCT order that absent the approved ORDC shifts, ERCOT's wholesale prices will likely remain low for two reasons. First, low natural gas prices are expected to persist. Second, a review of planned resource additions for the ERCOT market suggests that Texas's wind and solar generation is likely to increase, thus suppressing ERCOT's wholesale market prices (Zarnikau et al., 2019). Hence, duct-taping ERCOT's energy-only market structure by modifying the ORDC is deemed effective in mitigating ERCOT's capacity scarcity in the near term. But only time can tell whether this strategy will work in the long run.

Footnote

[1] Market forces alone are projected to yield an "economically-optimal" reserve margin of 9% and a market equilibrium reserve margin (additionally reflecting the original ORDC's impact) of 10.25% (Brattle, 2018).

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Bios

Student Happy Hour Gathering

BY PABLO BENALCAZAR, IAEE STUDENT COUNCIL REPRESENTATIVE

The Student Happy Hour and Gathering took place on Wednesday, May 29 at the Café-Bar Le Saint-Sulpice, well known for its garden terraces and nested at the famous Quartier Latin. The event is one of the most popular among all students and it is aimed at providing an informal evening where participants can widen their network and share ideas. Student Council Representative, Pablo Benalcazar, welcomed all student members and went on to highlight the benefits of being a member of IAEE such as complimentary access to all conference proceedings and IAEE's periodical publications, reduced conference fees, eligibility to take part in the IAEE European PhD Day, compete in the Student Best Paper Award at the IAEE International Conference, present their work in poster sessions in a multitude of IAEE conferences, and join a Student Chapter.

Big Data Meets Local Climate Policy: Energy Star Time-of-Day Savings in Washington, D.C.'s Municipal Buildings

BY MAYA PAPINEAU

Maya Papineau is Assistant Professor in the Department of Economics, Carleton University, Canada, maya.papineau@carleton.ca She gratefully acknowledges the financial support provided by Smart Prosperity, University of Ottawa, Canada.

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Introduction

Municipal governments have a history of implementing a multitude of energy conservation policies over the past 30 years (Bulkeley (2010), Broto and Bulkeley (2013)). Local governments are desirable to evaluate a number of energy policies since over half of greenhouse gas (GHG) emissions originate in cities (Satterthwaite (2008), Bulkeley (2010)), and city governments manage or coordinate many policies with a direct impact on GHG emissions, such as energy codes, energy benchmarking ordinances, and transit investments.

Relatedly, a question that economists and policymakers have long considered important, but until recently could not precisely measure empirically, relates to whether energy conservation policies and investments deliver savings during peak demand times. This has changed with the advent of building-level smart meters and the resulting availability of high frequency energy consumption data.

The within-day distribution of energy savings is an important determinant of the benefits of energy conservation. Since the marginal cost of supplying electricity varies across hours of the day, energy-reducing programs with heterogeneous savings across hours will exhibit different values even if the aggregate quantity saved is the same. In particular, programs with a distribution of savings spread equally through the day are valued less than those that deliver more savings at peak price hours.

In most regional markets, there are key hours within a day with steep price increases, when marginal units coming online are frequently from fossil fuel-fired units. In the PJM regional market studied in this work, over the sample period the marginal fuel in any given hour is coal more than 50% of the time (Monitoring Analytics (2019)). Savings during these peak price hours will have higher net benefits, all else equal. For example, commercial heat pumps and chillers are 21% and 17% more valuable, respectively, than if the savings were spread equally across hours, and energy efficient air-conditioner investments are 16% more valuable. On the other hand, commercial lighting has a timing premium of only 2% (Boomhower and Davis (2019)).

This paper studies a benchmarking and public reporting `sunshine' policy adopted by the city of Washington, D.C., that has resulted in the availability of hourly electricity consumption data in the City's municipal buildings. I evaluate the distribution of hourly savings from changes in a building's monthly Energy Star score in Washington, D.C.'s municipal buildings. The results help to fill gaps in our understanding of the timing of energy savings from benchmarking policies in multi-tenanted institutional space.

The Energy Star portfolio manager, a building energy usage measurement tool developed by the U.S. Environmental Protection Agency, is the primary source for implementing benchmarking policies in the U.S. Over 450,000 buildings representing about half of commercial floor space have used the portfolio manager (EPA (2016)). While the Energy Star for buildings program has been estimated to reduce annual energy consumption per square foot by 2.5% per year (EPA (2012)), no work thus far have assessed the hourly distribution of savings from energy benchmarking.

Data

Since 2013, the D.C. municipal government has made public detailed data on hourly electricity consumption, building-level hedonic characteristics, and hourly outdoor temperature data as part of its Sustainable D.C. policy. For 139 of these municipal buildings, these data also include monthly Energy Star portfolio manager scores, which range between 0-100 and rank building energy use intensity (EUI) relative to a representative sample of buildings in the same sector, with a higher score representing more energy efficient buildings. A large share of these buildings are elementary, middle and high schools, while most of the rest are office buildings.

At the time the program was instituted, public statements by the City indicated the high frequency data availability would be used to identify equipment being inefficiently used past building occupancy hours, and to provide insight into which buildings require equipment retrofits.

Empirical Strategy

The estimating equation is:

$$Y_{i,h,d,m} = \beta_h(Score_{i,m-1} \cdot 1_h) + \theta T_{h,d,m} + \psi X_{d,m} + \eta_{i,h} + \gamma_c + \varepsilon_{i,h,d,m}, \quad (1)$$

where $Y_{i,h,d,m}$ is the level of energy consumption, in kWh, in building i during hour h on day d and month m. $Score_{i,m-1}$ measures the Energy Star portfolio manager score in building i for the entirety of the previous month, m−1. 1_h denotes a set of indicator variables equal to 1 in hour h, $T_{h,d}$ is the average Washington, D.C. temperature during hour h on day d, and $X_{d,m}$ denotes a vector of additional controls, namely dummy variables for weekend days and school holidays. The variable $\eta_{i,h}$ is a building-level fixed effect, γ_c is a calendar month fixed effect, and $\varepsilon_{i,h,d}$ is an error term. The variables of interest are the β_h coefficients that quantify the hourly savings profile of a one-unit increase in the portfolio manager score. In the preferred specification, with building-hour and calendar month fixed effects, the β_h are identified from within-building-hour and within-month differences between buildings with varying portfolio manager scores.

Results

The main result is presented in Figure 1. The Figure shows the point estimates for β_h. The hourly distribution of savings from a 1-unit improvement in the Energy Star score is effectively flat, with an average decrease of 0.65 kWh per hour. There is a small peak in savings at 6am, however it is not statistically different from the point estimates in other hours. Though not shown here, the savings profile for the summer months of June to September and the non-summer months are similarly flat.

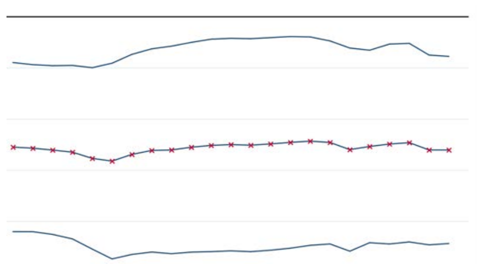

Figure 1: Annual Hourly Savings Estimates

Note: Blue lines represent 95% confidence interval. Standard errors are clustered at the building-month level. Building-by-hour and month fixed effects are included.

Comparing these estimates to hourly locational marginal prices (LMPs) in D.C., shown in Figure 2, it is clear that there is a mismatch in the profile of building Energy Star savings and hourly prices, particularly in the summer.[1]

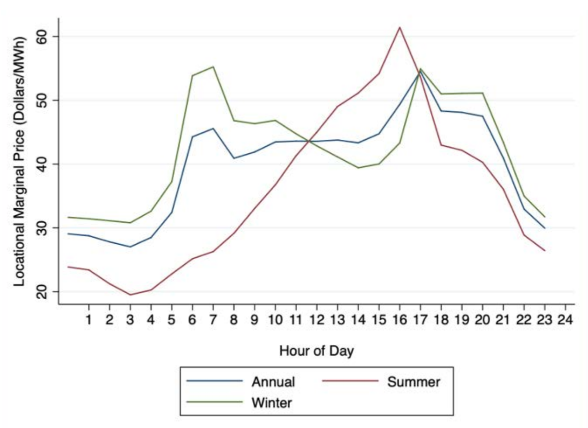

Figure 2: The hourly price of electricity in D.C.

This is further illustrated in Figure 3, which shows the profile of z-score standardized savings and prices, where each variable is normalized to have a mean of

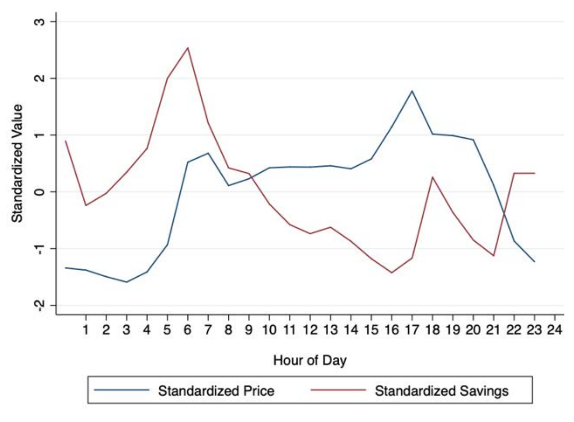

Figure 3: Comparing annual standardized prices and savings

zero and a standard deviation of one. Prices reach their peak at 5pm, and savings peak at 6am. The correlation between savings and prices is -0.41, indicating that prices tend to peak when savings are low and vice versa. In the summer months the correlation is -0.38, and in winter it is 0.55, so the negative correlation overall is primarily driven by a mismatch of savings and prices over the summer months.

Conclusion and future work

This case study of the hourly distribution of Energy Star score improvements in Washington, D.C. municipal buildings indicates a flat profile of hourly savings. Future work in this research project will incorporate capacity-payment adjusted price estimates and then assess total average savings versus savings adjusted for the hourly distribution of returns, in order to assess the value of the timing premium, if it exists.

Footnote

[1] These LMPs do not include capacity market payments, which suggests they represent an underestimate of peak-time prices and are therefore a conservative estimate of peak-off peak price differentials.

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Present and Future Welfare Loss Due to Electricity Tariff Inefficiencies

BY NIALL FARRELL

Marginal cost pricing guides economic efficiency. For electricity, a large proportion of costs are fixed and marginal cost pricing may lead to an under-recovery of total costs. Two-part 'Coasian' tariffs can facilitate marginal cost pricing, whereby volumetric tariffs are priced equal to marginal cost and a fixed 'standing charge' recovers fixed costs (Coase, 1946).

The current deviation from marginal cost pricing creates a welfare loss, but reform on Coasian principles may create distributional or environmental counter-effects. Alongside these concerns, the shifting structure of the electricity supply chain to accommodate Distributed Energy Resources (DERs) may also affect welfare distributions. As DERs substitute for grid-sourced electricity they bring a change in the revenue structures faced by utilities. If Coasian pricing is not in place, and therefore some fixed costs are recovered via volumetric tariffs, utilities must restructure their tariffs to ensure full cost recovery.

This Energy Forum article will summarise the findings of Farrell (2018) which provides two primary contributions. It first estimates the welfare loss due to the existing electricity tariffs in Great Britain, and compares this welfare loss to potential distributional and environmental counter-effects. The second contribution is to show the effects of DER deployment on welfare distributions. Under current British tariffs, DER deployment necessitates tariff rebalancing which redistributes welfare from non-adopters to adopters and leads to a net welfare loss in likely circumstances.

Simulating welfare change due to a Coasian tariff reform

The UK's Living Cost and Food (LCF) survey provides the foundation for this analysis. Electricity expenditures are converted to units consumed by matching each household to a tariff. Utility 'Consolidated Segmental Statements' (Ofgem, 2017) allows for the marginal and fixed cost breakdown to be identified. Using this information, a revenue-neutral Coasian tariff reform is calculated for the LCF population.

The second stage of analysis concerns DER deployment. Adoption is simulated amongst a subset of households. Utility revenues are calculated relative to costs and tariffs are recalibrated to ensure full cost recovery, if required. This is carried out for both current British tariffs and the Coasian counterfactual.

Welfare change due to Coasian tariff reform

Coasian volumetric tariffs are over 50 percent less than 2015/16 British tariffs. A Coasian tariff is in the region of £0.06/kWh, compared with current tariffs in the region of £0.14/kWh. Standing charges must increase from 350 to 450 percent under a Coasian tariff structure.

Niall Farrell is a Marie Sklodowska-Curie Fellow, Potsdam Institute for Climate Impact Research (PIK), Germany.E-mail: niall.farrell@pik-potsdam.de

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The welfare effects are predicated on consumers' price elasticity of demand, with the empirical literature finding that the long-run price elasticity of demand is in the range of -0.3 to -0.8, with many studies converging on the upper end of this spectrum. A change in consumer surplus is calculated using a constant elasticity of demand function, D(p) = Ak pe. Welfare changes are calculated as the area to the left of the demand curve, bounded by the original and Coasian volumetric price, less the change in the standing charge.

Current British tariffs create average welfare losses of £28 to £86 per household, per annum. These household-level welfare losses aggregate to average population-level losses of between £729m to £2,235m, or between 6 and 18 percent of domestic consumption value (Ofgem, 2017).

Distributional and environmental counter-effects

Distributional impacts are predicated on the price elasticity of demand. If the true elasticity of demand corresponds to that estimated by the empirical literature, all income groups benefit from tariff reform, on average. This is because of the large discrepancy between current and Coasian volumetric prices. Coasian reform creates a large demand response that outweighs the increase in standing charge for most households. This trend persists for those in low income groups.

As there are still those who lose out due to reform, current inefficiencies may be justified if the welfare cost of redistribution via existing tariffs is less than the welfare cost of redistribution via the next best alternative, the tax-benefit system. For every £1 raised through energy taxes in the UK, £1.13 is lost through economic distortion. For labour taxes, every £1 raised costs £1.81 (Barrios, 2013). Every £1 distributed via current tariffs costs between £2.02 and £5.98, which is greater than either benchmark. Distributional concerns are not irrelevant, however. While current tariffs cannot be justified on distributional grounds, these distributional effects are likely to be of policy concern. The findings of this analysis indicate strongly that these are more efficiently addressed via the tax-benefit system.

Coasian reform also presents environmental concerns. During the period of study, the carbon price floor in the UK was £18/tCO_2, lower than many estimates of the social cost of carbon. The UK Committee on Climate Change recommend that target-consistent carbon prices are in the region of £50/tCO2 (CCC, 2015). Accounting for the carbon price floor in calculations, this paper quantifies the welfare loss per ton of CO2 avoided of £119/tCO2. A correctly-specified carbon price is therefore likely a more efficient way to achieve carbon reductions than current tariff inefficiencies.

Distributed Energy Resources (DER) and Dodging the Deadweight Death Spiral

This paper also considers the welfare impacts of substituting a subset of household generation for DER-sourced electricity. No household is assumed to fully defect (and therefore substitution is infra-marginal). If a Coasian tariff is in place, utilities lose their marginal cost for each unit of electricity replaced by DER generation. If a Coasian tariff is not in place, utilities lose their marginal cost and a portion of fixed costs. A tariff surcharge is calculated to ensure full cost recovery. Both standing and volumetric tariff recalibrations are considered.

Under Coasian pricing, households will only adopt if the average cost of DER-sourced electricity is less than or equal to the marginal cost of grid-sourced electricity. These are circumstances that are welfare-improving. There are no negative distributional impacts; adopters benefit and non-adopters are unaffected as tariffs do not need to be changed. This removes worries of a `utility death spiral'.

When Coasian pricing is not in place, it is cost-effective to adopt once the DER price reaches parity with the retail price. Figure 1 shows that at retail price parity (c. 200 percent of marginal cost), deployment leads to welfare loss as grid tariffs are adjusted to ensure cost recovery.[1] The welfare loss of this adjustment is greater than the benefit to adopters. This can be up to £1,000 million per annum, or 10 percent of the value of residential electricity consumption, with 10 million adopters (33% adoption rate). Non-adopters, on average, lose up to £55 per annum under this scenario. Total welfare losses fall as DER costs fall. Total welfare remains unchanged at grid parity but welfare redistribution persists under current tariff structures; adopters benefit at the expense of non-adopters.

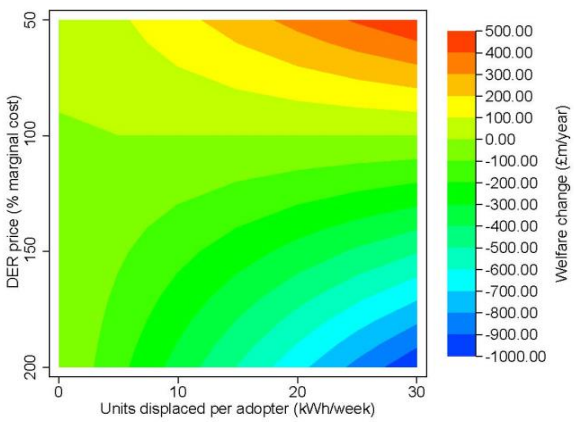

Figure 1: Total change in welfare due to 10 million DER adopters with no Coasian price and standing charge tariff adjustment

Conclusion

This paper has analysed the welfare losses arising from inefficient British electricity tariffs. A Coasian tariff reform may avoid welfare losses of up to 18 percent of domestic consumption value. This paper demonstrates clearly that environmental and social factors do not justify current departures from efficient tariff structures and distributional concerns should be addressed via the social welfare system. These findings will inform the ongoing tariff review processes being carried out by the UK regulator Ofgem.

This paper also shows that not only does Coasian reform lead to immediate benefit for consumers, it safeguards against potential future welfare losses. Without a Coasian price structure, DER deployment may necessitate tariff rebalancing to ensure full cost recovery. While the policy discourse is focussed on a `utility death spiral', the under-recovery of network fixed costs due to a major decrease in the volume of sales, this finding draws attention to a potential `deadweight death spiral', where growing welfare losses due to increasing distortions outweigh the benefits of technological change.

Footnote

[1] We present results due to standing charge adjustments. Please see Farrell (2018) for a discussion of the results due to volumetric tariff adjustments, which are of similar magnitude.

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Resource Booms and the Macroeconomy: The Case of U.S. Shale Oil

BY NIDA CAKIR MELEK, MICHAEL PLANTE AND MINE YÜCEL

Overview

Technological advances in horizontal drilling and hydraulic fracturing have led to an unprecedented increase in U.S. oil production. Often referred to as the shale revolution, the boom in U.S. oil production has renewed interest in the long-standing question on the link between resource booms and economic performance. There are several recent papers focusing on the local or regional implications of the U.S. shale boom, suggesting positive economic effects (see, for example, Feyrer et. Al (2017) and Allcott and Keniston (2018)). However, little is known about the implications of this boom for the U.S. aggregate economy and trade. In this paper, we study the importance and implications of the U.S. oil boom for the U.S. economy, trade balances, and the global oil market in a dynamic stochastic general equilibrium model of the world economy that takes into account unique characteristics of the U.S. experience: a large increase in production of a certain type of crude oil with an oil export ban in place.

The relatively few general equilibrium models that feature oil generally assume that oil is a homogenous good. This is a strong assumption since the characteristics of oil can differ across several dimensions, one of which is density. A key feature of the recent U.S. oil boom is that oil produced from shale deposits via the application of horizontal drilling and hydraulic fracturing is predominantly one type of oil: light crude. Different types of crude oil are imperfect substitutes for each other in the refining process and refining sectors tend to specialize in processing certain types of oil. The U.S. refining sector is specialized in processing heavier crude oils relative to the rest of the world. This mismatch of increased supply of light oil and existing refining capacity for heavier oil in the U.S. has important implications for the use and trade of various types of crude oil. These implications were potentially exacerbated by the U.S. export ban on crude oil, a policy which was in effect until the end of 2015.

In assessing the implications of the U.S. light oil boom, we make two contributions to the literature. First, we introduce two sources of heterogeneity into a general equilibrium model with endogenous oil prices: we consider three different types of oil that are imperfect substitutes into the refining process, and we assume differences between refineries in the U.S. and the rest of the world (ROW). Second, we assemble a comprehensive data set that contains information on crude oil quality in order to build our model on solid microeconomic foundations. One key point to highlight is the importance of examining detailed oil data and introducing heterogeneity in crude oil types and refining technology. If we were to only use aggregate data and pool different types of crude oil into one single oil sector, we would not be able to assess the implications of the shale oil boom for trade in different types of oil, relative prices of oil, and specialization. In addition, examining the distortionary effects of the crude oil export ban would not be possible.

Nida Cakir Melek is an economist at the Federal Reserve Bank of Kansas City, Kansas City, MO; **Michael Plante** is a senior economist at the Federal Reserve Bank of Dallas, Dallas, TX; **Mine Yücel** is a senior vice president at the Federal Reserve Bank of Dallas, Dallas, TX. Email: mine.k.yucell@dal.frb.org

Key changes in the data from 2010 to 2015

We gather data on production and prices of different types of crude oil as well as trade flows and refiner use of different types of oil. We define three categories of crude oil using API gravity as our metric. Our time period is 2010-2015, from the year the boom started, to the removal of the ban. We document that from 2010 to 2015 U.S. light oil production more than tripled, while production increases outside the U.S. were from medium and heavy crudes. In addition, U.S. refiners' use of light oil increased substantially, while medium crude use declined and heavy crude use increased from 2010 to 2015. Refined products production and exports increased considerably, as the export ban did not apply to refined petroleum products. We document dramatic shifts in the quantity and types of oil being imported as well: U.S. light oil imports dropped sharply, medium oil imports declined and heavy oil imports increased with the shale boom. These facts help justify the features of our model.

Methodology

The world economy is represented by a dynamic stochastic general equilibrium model that consists of two countries, the U.S. and the rest of the world (ROW), building on Backus and Crucini (2000) and Bodenstein et al. (2011). The key differences are that we introduce heterogeneous oil, endogenous oil production and refining. Our model also features an occasionally binding export ban on U.S. crude oil. Both countries produce crude oil, refined products (fuel), and a non-oil good. Their preferences and technologies have the same functional forms. Crude oil is produced using the non-oil good as an input and is used only to produce fuel. Production of refined products requires capital, labor, and a composite of the three types of crude oil with different elasticities of substitution across inputs. The non-oil good is produced using capital, labor, and refined products. Households consume a composite of fuel and the non-oil good. The model also features an internationally traded bond to allow for trade imbalances.

We solve the model numerically, which requires us to calibrate the model. We obtain micro estimates of three key model parameters using simulated method of moments: the elasticities of substitution across different oil types and the elasticity of substitution between oil and other factors of production. We carefully calibrate the remaining model parameters targeting a set of first and second order moments for oil-related and macro variables.

Our goal is to investigate the effects of the U.S. shale oil boom on the U.S. economy, trade, and the global oil market. We model the shale oil boom as a series of exogenous technology shocks that lower the cost of producing light oil in the U.S. Given that the export ban was in place, our baseline model incorporates the ban. We also consider the U.S. shale boom in an alternative model that ignores the ban, i.e. a free trade model.

Results

We find that the shale boom had significant effects on the U.S. economy, trade flows and the global oil market. In addition, the export ban was a binding constraint, particularly in 2014 and 2015, and likely would have remained a binding constraint thereafter, had the policy not been removed at the end of 2015.

Our model can match several important aspects of U.S. oil market data during the boom. We find that the increase in light oil supply causes light oil prices and fuel prices to fall. U.S. refiners increase their use of light oil but much of the new production simply crowds out imports of light oil, as in the data. The decline in imports generates a major improvement in the U.S. oil trade balance, by more than one percentage point (as a share of GDP), in line with the data. The decline in light crude oil imports is large enough to make the export ban a binding constraint for several years. Properly modeling and calibrating the refinery sectors is key to this result, as it is driven by the fact that the U.S. refinery sector is specialized in processing heavy crude relative to the rest of the world.

The export ban distorts light crude oil prices in the U.S. relative to the rest of the world and relative to other types of crude oil, providing a cost-advantage to U.S. refiners who over-process light crude oil and take market share from refiners elsewhere. We also show that had there been no ban during the shale boom from 2010 to 2015, domestic light oil prices would have been higher and the U.S. would have become a net exporter of light crude oil consistent with the recent data.

During the boom, cheaper fuel prices boost household consumption and firm fuel use and increase both non-oil output and aggregate consumption, implying positive spillovers to the aggregate economy. We find that the shale oil boom boosted U.S. real GDP by 1 percent from 2010 to 2015 which accounts for about one tenth of actual GDP growth over this period. This suggests that the boom has contributed to the recovery from the Great Recession.

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Pre-conference Seminar-Equilibrium Methods for Analysis of Environmental Policy in the Power Sector

SUMMARIZED BY AMOS OPPONG, DOCTORAL RESEARCHER, UNIVERSITY OF ELECTRONIC SCIENCE AND TECHNOLOGY OF CHINA

On May 28th, a day prior to the commencement of the IAEE International Conference, 28 participants including three experts and twenty-five young professionals from diverse academic backgrounds and various institutions around the globe met at HEC Montreal for a seminar on exploring a plethora of equilibrium methods used in analyzing environmental policy in the power sector.

Associate Professor *Yihsu Cheng* of Baskin School of Engineering at the University of California, Santa Cruz, USA; Professor *Makoto Tanaka* of the National Graduate Institute for Policy Studies, Japan; and Professor *Afzal S. Siddiqui* of University College London [UK], Stockholm University [Sweden], and HEC Montreal [Canada]; collaborated well with each other and successfully steered the contents of key topics discussed in the seminar to address concerns in the power sector that hitherto troubled participants.

The three experts combined interactive tools including in-depth introduction, robust mathematical modeling, and real-world case studies to delve deeper into the numerous topics discussed at the seminar. Topics discussed include environmental externalities, policies and features of power sectors; equilibrium solutions in cases of mixed complementarity problems, environmental policies in Nash-Cournot as well as Stackelberg leader-follower frameworks, and decentralized approach versus central planning for sustainable transmission expansion in power markets. Participants interacted well with one another, networked among themselves and asked a myriad of questions to the experts and peers during the seminar and at the student gathering at Café-Bar Le Saint-Sulpice [on May 29].

The organizers extend their gratitude to the Professors and participants for making the seminar a success.

The Relative Inefficiency of Petroleum Fiscal Regimes in Latin America and the Caribbean

BY GRAHAM A. DAVIS AND JAMES L. SMITH

Graham A. Davis is Professor Emeritus, Division of Economics and Business, Colorado School of Mines, gdavis@mines,edu and **James L. Smith** is Professor Emeritus, Department of Finance, Southern Methodist University, jsmith@mail.cox.smu.edu

See footnote at end of text.

There has long been interest over fiscal mechanisms by which governments can appropriate rents from mining and petroleum operations. Typical mechanisms include royalties, income taxes, and carried interests. For many Latin American and Caribbean (LAC) countries these revenues can be important sources of funding for social programs and development. Yet economic policy with respect to mineral wealth poses a series of challenges. Primarily, fiscal arrangements need to ensure that governments benefit from the financial gains associated with natural resource exploitation without adversely impacting private sector exploration and investment, without which these resources would produce no value.

Of particular interest, therefore, is optimal taxation design. Optimality includes considerations of the effect of taxation on operating decisions. Does taxation sterilize reserves? Does it affect the speed of extraction? How efficient is a given suite of fiscal terms within a country at capturing the greatest economic rents without distorting investments and operations in ways that reduce the potential value of the resource? And, given that tax revenues often fund important social programs and development, when does the government begin to receive payments from the project?

Over the last few decades, thinking on natural resource taxation has evolved in many leading mining and hydrocarbon producing countries towards developing non-distortionary fiscal tools. The fiscal systems applied to mining and oil and gas in LAC have, however, largely escaped such comprehensive and comparative analyses. This report examines the performance of mining and petroleum taxation policies in thirteen Latin American and Caribbean mineral and energy producing countries, and in particular for 26 petroleum projects and 15 mining projects representative of the region. We focus on the ability of each country's system of taxation (i.e., fiscal regime) to foster development of these projects in a manner that efficiently exploits the resource while allowing appropriate flows of project rents to the Government. Depending on the country and the fiscal regime in place, these flows may take the form of income tax and/or special tax revenues, production royalties, participation in production and profits, cash bonus bids, land-use and licensing fees, and mandated contributions to various socially-oriented funds.

Each country included in the study has developed its own, very unique fiscal regime for petroleum and mining—no two are alike, not even across the two sectors. Some are quite simple, but many are complicated. For oil and gas, both Production-Sharing contracts (PSC) and traditional Concessionary systems are in common usage. Indeed, some individual countries employ both types of fiscal regimes. In mining, there is no production-sharing or bonus bids, but instead up to six different types of taxes by which rents are transferred to the Government or approved social programs.

Of utmost importance is the ability of each fiscal regime to efficiently capture economic rents for the nation without unduly discouraging exploration and resource development. Equally important is the robustness of the chosen regime to perform well under a range of economic circumstances, including high versus low prices and high versus low costs, as well as under a range of project specifics, such as deep water versus shallow water oil and different metals and types of mines.

We have examined the performance of each regime with respect to these factors via the optimization of an engineering-economic model of each project both before taxation and after taxation using the methodology in Smith (2014).[1] All the regimes induce Operator distortions, with subsequent deadweight loss. The petroleum fiscal regimes tend to be more distortionary than the mining regimes, with an average deadweight loss of 18% versus 4% for development stage projects at base-level market prices. To put this 18% deadweight loss into perspective, for the average dollar raised by the government through petroleum taxation, 45 cents of project rent is destroyed. The worst systems that we modeled destroy more than $1.00 of social rent per $1.00 of tax revenue raised. When we back up and evaluate exploration-stage petroleum projects the deadweight loss rises to 33%, with the tax burden extinguishing private sector investment completely at three of the 26 projects modeled. The petroleum regimes are relatively inefficient compared with mining in large part because of their extensive reliance on less efficient fiscal instruments like royalties.

The Government Take of total project rents averages well over 50% for the projects we examined, with the highest Government Takes generally causing the most distortions and as a result being least efficient. Figure 1 presents the Fiscal Yield of the fiscal systems as applied to the 23 petroleum exploration projects that remain viable under taxation. Fiscal Yield is the percentage of no-tax project rent or value captured by

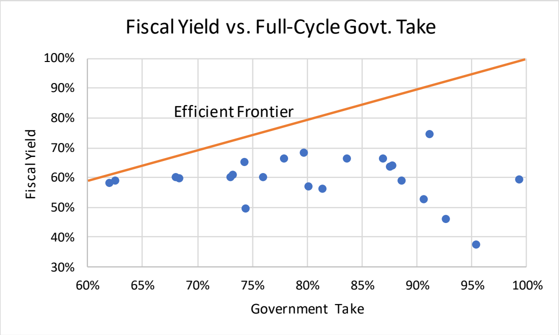

Figure 1: Fiscal Yield vs. Government Take, 23 Viable Petroleum Exploration Projects

the fiscal system, with a higher Fiscal Yield revealing higher absolute government revenues for a given project. A perfectly efficient tax would fall along the Efficient Frontier shown in the figure. It is clear that the petroleum regimes are inefficient. For several projects the fiscal system is so aggressive as to create a lower yield compared with projects that face a lower Government Take. The Laffer curve is at play.

A notable result of our analysis is that the impact of a fiscal regime depends greatly on the specifics of the project being taxed. That is, the distortionary effects within a fiscal system are not uniform across the projects to which the system is applied, and incorrect inferences could be drawn by passing the fiscal system through a single "representative" project. Nor are the distortionary effects independent of project economics, with more distortions as economic and physical conditions change to create lower pre-tax profit margins and higher effective tax rates.

What can be done to improve fiscal efficiency in petroleum taxation? The literature on effective resource taxation is plentiful, and generally advises against the fiscal practices being used in LAC in favor of neutral taxes like cash flow taxes or resource rent taxes. No LAC country that we examined has attempted to design a neutral taxation system. The lowest inefficiencies were found in Chile (for mining) and Guyana (for petroleum), largely because of their relatively low rate of taxation and their emphasis on profits taxes rather than sales or production royalties. The simplest way to reduce the existing distortions in the petroleum fiscal regimes is to apply lower rates of taxation. Then there is the more sophisticated path of replacing the existing fiscal systems with rent taxes. An intermediate step would be to place more weight on corporate income taxation (CIT) as a way of taxing resource projects, as with special surtaxes above and beyond the global corporate income tax rates such that the desired level of government revenue is achieved. Our simulations show that when CIT allows for unlimited loss carryforwards and accelerated depreciation combined with intangibles expensing, these instruments perform quite well. Using only an elevated CIT to effect a 55% Fiscal Yield on a hypothetical petroleum exploration project created a 10 cent value loss for every dollar raised. Applying only royalties to raise that same level of government revenue caused 40 cents of value loss per dollar raised.

When judging any fiscal regime either before or after these modifications, it is important to understand that the performance of a fiscal regime should not be assessed using the conventional measure of Government Take. Although that measure represents the fraction of realized profit from a given project that is captured by the government, it fails to account for investments that are not made and potential government revenues that are never generated due to tax-induced distortions. Fiscal Yield is the more useful measure of a fiscal system, as it reveals just how much of a project's inherent value flows to the government.

Footnote

[1] The model was revised by Davis and Domínguez (2017) for applicability to mining projects, and implemented by CRU after extensive model buildout.

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Dual Plenary Session 1: Energy Modernization and Transition

SUMMARIZED BY ANTHONY FRATTO, M.S. CANDIDATE, MASSACHUSETTS INSTITUTE OF TECHNOLOGY

As nations and localities seek to decarbonize their energy system, the policy, experiences, and motivation is critical to understand. These three speakers addressed the role we as economists play, as well as highlighting the issues, and institutional foundations necessary for such an energy transition.

Chris Knittel (Massachusetts Institute of Technology), opened up the plenary emphasizing economists' role in helping influence energy transition policy and goal setting. He asserted that 2nd/3rd best policies should be supported if they are welfare enhancing and their costs are on visible. Furthermore, Knittel noted that it is imperative we complete more work on the effect of these policies on the most vulnerable populations, including a redesign of ratemaking. Economists are

Continued on page 22

Market Power in the NZ Wholesale Electricity Market 2010-2016

BY STEPHEN POLETTI

Stephen Poletti is with the University of Auckland. s.poletti@auckland.ac.nz

Overview

Over a decade ago the NZ Commerce Commission engaged Frank Wolak to investigate market power in the New Zealand wholesale electricity market. Professor Wolak (2009) found evidence of substantial market power with market power rents of $4.3 billion over the seven-year period (2001-2007) covered by the report. There were a number of criticisms of the report, the most substantial of which was the assumptions made around the value of water, which was capped at the marginal cost of thermal plants. Browne et al (2012) using a different methodology argued that water values during dry years would at times be higher than this. Using a computer agent based approach to model market power and a calibrated water value curve they found similar market power rents to those calculated by Wolak. Philpott and Guan (2013) using stochastic dynamic programing to calculate water values also found high market rents.

Since the Wolak report, Browne et. al. (2012) and Philpott and Guan (2013) there has been no quantitative investigation into market power in the NZ wholesale market, even though there have been considerable changes in market conditions. Despite little demand growth over the last decade there has been a significant increase in new wind and geothermal generation. More recently, a number of thermal plants have exited the market and there have also been line upgrades. Furthermore there has been a number of market design changes aimed at alleviating market power and managing risk better in years of low inflows into the hydro dams. Thus it is timely to investigate whether there are still market power issues in the wholesale market.

Methods

The approach used in this report to model market power is to construct the competitive benchmark, where all plants bid into the market at their marginal cost. There is one exception - hydro bids into the market using the water value. The water value curve is computed as a function of the actual lake level, compared to the mean, for any given day. We compare the competitive benchmark to the prices simulated by the computer agent-based firms trying to maximise profits and attribute the difference as market power rents. We also compare the competitive benchmark to actual prices and compute rents using this approach. It turns out both approaches give similar results.

We start off using the approach advocated by Browne et. al (2012), to investigate market rents over a seven year period from 2010-2016 using computer agents. This approach gives substantial market rents. However we argue that there is a dynamic inconsistency in this approach, as the competitive benchmark consistently dispatches more water than the strategic simulations, which cannot continue for any length of time as the lakes would eventually become empty. We constructed a model that is dynamically consistent by keeping track of dispatch and inflows for each time period and updating the lake level to find new water-values in the following period. This is our preferred approach as it is dynamically consistent and has simulated prices close to actual. We compare simulated prices to the competitive benchmark to calculate market rents.

Results

Over the period of the study simulated average prices were $63/MWh compared to the average of observed prices which was $68/MWh. The close agreement gives us confidence in the methodology. The computed markets power rents over the period 2010-2016 are substantial. They are similar or even higher, as a fraction of revenue, to those found by Wolak (2009). Table (i) below shows computed market power rents for each year using our dynamic competitive benchmark and market power simulations. Over the 7-year period of the study total simulated market revenue was $14.9 billion. Total market rents are $5.4 billion, which is 36% of revenue.

Year	Simulated Competitive Benchmark Revenue ($million)	Simulated Market rents ($ million)	% of total revenue	Simulated Wholesale Revenue ($million)
2010	1861	588	24%	2449
2011	1668	678	29%	2346
2012	1569	1305	45%	2874
2013	1146	554	33%	1700
2014	1290	831	39%	2121
2015	1142	759	40%	1901
2016	856	688	45%	1544
SUM	**9532**	**5403**	**36%**	**14935**

Table i: Simulated market power rents.

Using actual prices to compute market rents instead of simulated prices market rents as a fraction of revenue are even higher at 39%, reflecting the fact that actual prices are slightly higher than simulated prices.

Conclusions

Having reported in detail for the different methods of simulating market power for each of the seven years 2010-2016, there are some general points that emerge. The first is that all the methods give market rents which are high. The second is how important lake level dynamics are. Ensuring dynamic consistency generally resulted in a large fall in simulated rents. The third point is that nearly all of the simulations tracked actual average annual prices well, with simulated average annual prices typically between 0-$10/MWh of those observed.

To sum up our analysis finds substantial market power in the New Zealand electricity market. Across the seven years we analyse we estimate, using our preferred methodology, total market rents at $5.4 billion, which is 36% of revenue. This is despite policies introduced over the time frame of this study with the goal of mitigating market power. Furthermore there is some evidence that market power rents have increased over the last few years.There is a strong case for policy intervention by the regulator to mitigate market power.

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Dual Plenary Session 1 (continued from page 20)

critical players in this energy transition, providing key analysis of goals, costs/benefits, impacts. However, Knittel argues, we are not policy makers, and should avoid predicting which policies are feasible but rather stating which ones are welfare enhancing.

ZhongXiang Zhang (Tiajin University) spoke to the experience of China's energy transition, addressing their issues of price elasticity, inflation effects, and the curtailments of wind and solar as they seek a low carbon society. Zhang argues the transition will require regionally coordinated action and institutional innovation. He concluded by offering up a few reforms in China which include liberalizing parts of the coal value chain and establishing a competing power market separate from transmission and distribution.

Lastly, Johanne Gélinas spoke to the role of Transition énergétique Québec in helping Québec reach its energy modernization goals. Québec's energy transition ecosystem includes a carbon market whose monetary returns go into a "Green Fund." This fund is used to address Québec's Climate Action Plan and facilitated by Transition énergétique Québec, who design programs that will reduce GHG emissions and ensure a low carbon Quebec. Québec's future targets include enhancing energy efficiency by 15%, reducing the consumption of petroleum products by 40%, and increasing renewable energy production by 25%.

Dual Plenary Session 2 – Market Access and Infrastructure

SUMMARIZED BY BORIS SOLIER, ASSISTANT PROFESSOR, UNIVERSITY OF MONTPELLIER

The session was chaired by Peter R. Hartley from Rice University who introduced the three panelists: Jean-Denis Charlebois from the National Energy Board of Canada, Jean Côté from Suncor and Jürgen Weiss from The Brattle Group.

Jean-Denis Charlebois reviewed the evolution of fossil fuels production and transmission capacities in Canada over the last few years. He showed that crude oil exports have increased faster than pipeline capacities, resulting in a higher utilization of railroads, while in the case of natural gas, capacity and production have evolved at the same pace overall. Turning to electricity, Jean-Denis Charlebois reminded that Canada enjoys a diverse electricity mix dominated by hydroelectricity, and argued there is a need for infrastructure to support the low carbon energy transition.

Jean Côté introduced Suncor's business, an oil and gas producer with assets in renewable generation, and the efforts undertaken so far by the company to reduce its carbon footprint. He stated that Canada has still a large share of fossil fuels resources to exploit and claimed for more stability and clarity in energy regulations.

Jürgen Weiss estimated the need for infrastructure investments to support the electrification of energy demand in the United States. He stressed that electricity distribution facilities will be the cornerstone of the future energy system but transmission infrastructure will still have a role to play at the US level, for instance to ensure exchanges across States when necessary. Hence, if investment in electricity infrastructures will need to double in the future in order to meet growing demand, the situation is less clear when looking to the whole energy system, according to Jurgen Weiss. Regarding oil and gas pipelines in particular, the question is whether or not to invest in assets that are likely to be stranded by 2050. Jürgen Weiss considered nonetheless that additional investments will probably be needed in fossil fuels infrastructures as full electrification of demand will not be easy to achieve.

Optimizing the Use of Curtailed Power in the Electric Grid

BY AHMED ABDULLA AND KRISTEN R. SCHELL

Introduction

Deep decarbonization of the energy system over the course of this century is a prerequisite to averting the worst consequences of climate change. Many decarbonization pathways have been proposed, most of which envision a substantial expansion in the deployment of variable and intermittent renewable energy sources, mainly solar and wind power [1-3]. What is new in more recent climate and energy models has been an increase in the likelihood that net negative emission technologies will be required to achieve the targets enshrined in international climate accords, whether the target is a 2°C or 1.5°C rise in average global temperatures [4].

To achieve this carbon removal, models employ a singular technology—bioenergy with carbon capture and sequestration (BECCS)—the scalability and environmental impacts of which remain uncertain [5,6]. On the other hand, solar and wind power have both proved scalable: over the past decade, decreasing costs and strong government incentives have propelled a more than fifty-fold increase in installed solar power capacity worldwide, from 9 gigawatts (GW) globally in 2007 to 500 GW in 2018 [7]. Installed wind power capacity has increased more than six-fold over the same period [8]. Concurrently, however, several major electricity markets have also seen an increase in both solar and wind power curtailment—the shutting down of electricity production from these generators because the system cannot integrate it. In the first four months of 2018, the California Independent System Operator (CAISO) was forced to curtail more than 210 Gigawatt hours of wind and solar power, and CAISO is expecting these levels of curtailment to increase as more renewables are installed in pursuit of the state's ambitious renewable energy goals [9]. This curtailment reduces generator availability and revenue; on the level of the system, it adversely impacts both power system reliability and generation expansion planning.

Here, we lay the groundwork for a new stream of research that investigates the extent to which the large-scale deployment of solar and wind power can encourage complementary carbon removal by other means. Specifically, we analyze how to transform curtailment risks into benefits by describing the extent to which curtailed electrons could power a suite of technologies that could amplify emissions reduction.

Data & Methods

Our model is empirically grounded in a four-year record of curtailment across the CAISO system and the locational marginal prices (LMPs) at each of the 2,202 aggregated pricing nodes within it. The relationship between these two parameters is shown in Figure 1.

Ahmed Abdulla is with the University of California, San Diego and Carnegie Mellon University, email: ayabdulla@ucsd.edu
Kristen R. Schell is with Rensselaer Polytechnic Institute, schelk@rpi.edu

Using these data and cost and performance parameters for three technologies that could mitigate anthropogenic carbon emissions, we develop a large-scale technology portfolio optimization model that optimizes the location and scale of technology deployment required to exploit both curtailed generation and electric power from the grid when the price of electricity in CAISO is so intensely negative that it justifies the operation of these systems. The three technologies we investigate are direct air capture of carbon dioxide, power to gas technologies, and utility-scale deployment of energy storage in the form of Lithium-ion batteries.

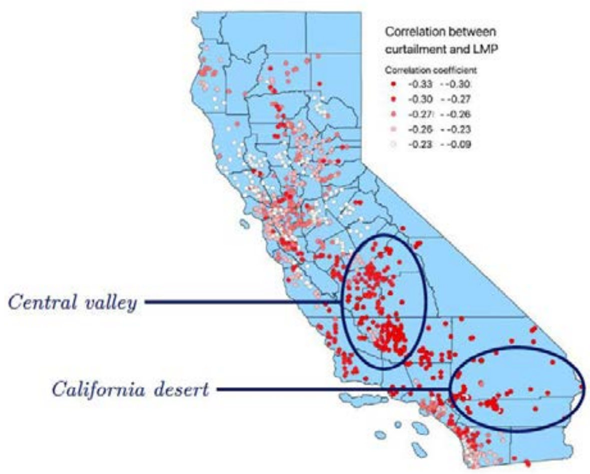

Figure 1: Pearson correlation between curtailed electric power and locational marginal prices (LMPs) across the CAISO system. Pockets of negative correlation exist in locations with high renewable generation and in urban areas, where local transmission constraints exist.

The large volume of empirical data necessitates decomposition of the optimization problem. We employ Bender's decomposition to solve the technology portfolio optimization.

Results

Our results suggest that carbon dioxide removal occurs through two methods. The vast majority is supported by curtailed energy, and this curtailment is done mostly through direct air capture technologies, which operate at lower cost than their alternatives, at least according to the fairly optimistic cost assumptions made by their developers [10]. Together, direct air capture technologies are responsible for the removal of more than 6.2 million tons of carbon dioxide over the course of the four years under investigation.

A small amount of CO_2 removal is supported in areas with characteristically negative locational marginal prices (LMPs). Ten percent of the CAISO system has LMPs negative enough to support carbon removal technologies, though these would operate intermittently and at high marginal cost. In total, these two methods could remove approximately 6.4 million tons of carbon dioxide over four years, which is equivalent to removing approximately 1.3 million cars from the road for a year. Figure 2 shows a summary of these results, identifying the location and type of technologies deployed across the CAISO system.

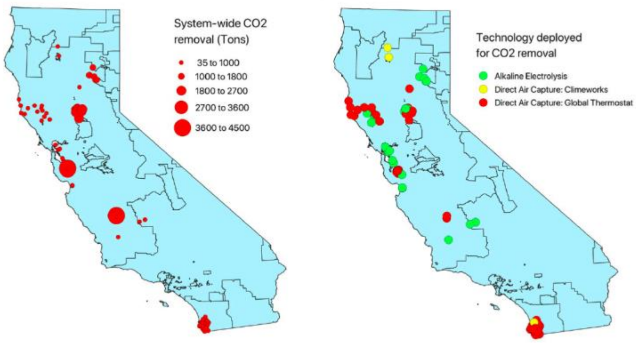

Figure 2: Assessments of the system-wide carbon dioxide removal potential across the CAISO system (left), and the type of technologies that are preferentially deployed throughout the state (right). Direct air capture technologies are preferred because they operate at lower costs, albeit according to the fairly optimistic cost assumptions made by their developers.

Conclusions

This research presents a novel method of amplifying the emissions reduction that could be achieved through deep penetration of renewable energy sources, while at the same time alleviating the problems inherent in their variability and intermittency. We employ a technology portfolio optimization model and Bender's decomposition to assess the extent to which curtailed and negatively priced electricity—a consequence of the deployment of variable and intermittent renewable energy sources—can be used to power a suite of technologies that reduce carbon dioxide emissions, either directly or by substituting the source of these emissions for products with lower carbon intensity.

Our work is intended to enable both energy system modelers and policy makers to begin considering the upside of curtailment, which is rightly deemed to be a major challenge to the power system. Moreover, we show how a range of emergent climate change mitigation strategies can produce fairly substantial benefits. If climate change mitigation becomes a bottom-up endeavor, as appears likely, these new strategies could work alongside traditional policy instruments as we seek to deeply decarbonize the global energy system.

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Attendee Comments

Kelly Stevens,

Assistant Professor, University of Central Florida

"It is good to have an opportunity to hear international perspectives. There is not as much happening in climate policy in the US so sometimes you need to look abroad to learn what is working else ware."

The Productivity Puzzle in Network Industries: Evidence from Electricity, Gas and Water Sectors

BY KARIM L. ANAYA AND MICHAEL G. POLLITT

The authors are at the Energy Policy Research Group, University of Cambridge. Corresponding email: k.anaya@jbs.cam.ac.uk.

This study is based on a previous study written by the authors (Ajayi et al, 2018) for Ofgem.

Introduction

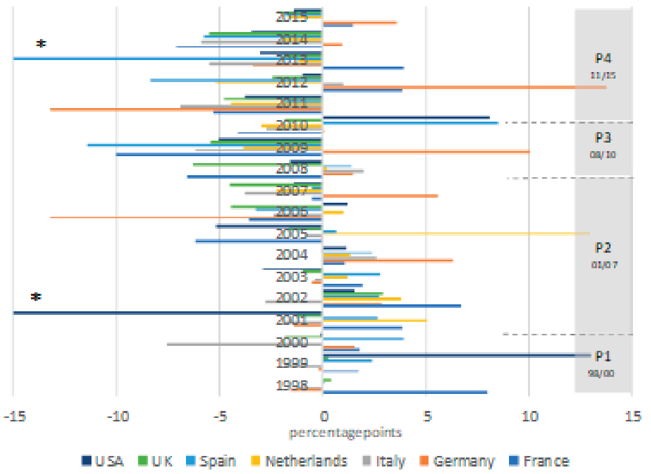
This paper examines the existence of a productivity puzzle in energy and water sectors. It looks at the value added total factor productivity (TFP) growth of the combined electricity, gas and water sectors (EGW) using the EU KLEMS database for the period 1998-2015. The productivity puzzle relates to the observation that overall productivity is flat-lining (and in some cases, falling) in many advanced economies after decades of steady growth. We compare the trend of UK productivity growth with its peers (France, Germany, Italy, Netherlands, Spain, USA) for the different network industries. Even though five out of the seven countries in this study are among the world's ten largest economies, trend productivity growth in most of them has been negative or very low in the last decade. This study compares our sectoral growth rates with overall industry growth for our seven countries and evaluates the contribution of inputs (labour and capital) to the growth of value added.

Methods

Growth Accounting measures the growth of economic activity by examining changes in a set of inputs (such as labour, capital and intermediate inputs) over time and by an unaccounted or unexplained growth (known as the Solow residual) which represents the total factor productivity (TFP) growth. The TFP growth estimations and discussion in this study are based on the growth of value added instead of gross output then intermediate inputs have been excluded from the TFP analysis. Theories about growth accounting methods and applications have evolved over time following some influential studies. The EU KLEMS database makes use of the growth accounting methodology for estimating the value added growth and the factors that contribute to it, for details see Timmer et al. (2007).

Results

Results from the TFP analysis of the EU KLEMS data show that for the period of study TFP growth for EGW sectors in general had a positive contribution to the value added growth during the period 1998-2005, with some exceptions, see Fig. 1. However, over the whole period of analysis, average annual TFP growth has been negative for all the countries except for Germany and Netherlands. Italy has the lowest average annual TFP growth. A closer look indicates that Italy has performed badly even before the financial crisis in 2009 and worse after it, with a peak negative TFP growth in 2000 (-7.5%). This is not surprising, considering that Italy is one of the worst performing economies in the Eurozone. A long-lasting impact on Italy's economy is expected because of the financial crisis (Morsy and Sgherri, 2010). In the USA, EGW sectors have been noticeably affected by the 2001 dotcom crisis. In the case of the UK a negative average annual TFP growth is observed before the 2008 crisis, starting in 2005. During the financial crisis and the years after (2008-2010), TFP growth for EGW sectors was negative, excluding Germany. France was the most affected (-7.00 p.a.). After 2010 EGW sectors show an anaemic improvement in TFP growth in France and the UK, but in both cases still below zero. For the period 2011-2015, Germany had a positive average annual TFP growth but Spain and Italy showed negative TFP growth. The consequences of the European debt crisis in 2011/12 may explain the continuing shrinking of the TFP growth for EGW sectors in the period 2011-2015. According to EC (2013), the impact of the crisis on GDP and employment (combined) for the period 2007-2011 was very high in Spain, high in Italy and moderate in the UK and France. It is clear that TFP growth for EGW sectors have suffered from the consequences of economic downturns but to different extents. TFP growth rates have not returned to the pre-crisis levels (2005 and backwards). In the case of the UK, a continuation of the TFP growth downward trend is envisaged because of



(*) USA and Spain with a negative annual TFP growth of 15.5 and 21.9 in 2001 and 2013 respectively.

P1: period 1998/00, P2: period 2001/07, P3: period 2008/10, P4: period 2011/15. Source: EU KLEMS da

Figure 1 TFP Growth for EGW Sectors per Year the uncertainty following its Brexit referendum in 2016.

Looking at the average annual TFP growth of all industries in our countries, it is noticeable that EGW sectors have been hit more (with lower annual growth rates), except in Germany. Italy and Spain also have a negative annual average TFP growth for all industries. There are other factors that may also contribute with the downward trend of TFP growth in our EGW sectors, many of them supported by a set of regional (European) and national sector reforms in favour of the energy transition and water security. These might include substantial increases in capital cost due to the addition of renewables and increased interconnection and lower demand as a result of increased energy efficiency (which itself might add capital costs). Meanwhile increased renewable generation displaces fossil fuel plants and lowers wholesale prices. This implies higher input costs at time of lower revenues (and apparent value added) and hence lower measured TFP growth. In general, an increase in electricity generation is observed from 1998 to around 2007/08 but a deaccelerated/flat growth rate after that. Lower energy consumption is also observed across our countries. For instance, final consumption (energy use) decreased in 5 out of 6 European countries during 1998-2017. An evaluation of household energy consumption shows that 3 out of 6 European countries decreased their consumption, with Germany the one with the highest reduction, 19.6% (1998-2017). In the UK a decrease in both electricity and gas household consumption. The other driver could be that increased competition in the energy market (for both wholesale and retail gas and electricity) may contribute to lower prices. One way to measure competition is to look at market share of the largest firm. We note that the share in electricity generation has decreased over time (excluding France). Italy and Spain are the ones with largest reduction during the period 1999-2016, while Germany and the UK kept a flat share. In terms of the water sector, increased water stress (due to climate change and rising population) has led to pressure to reduce water consumption and water system losses. Italy, Germany and France are among the European countries with the lowest freshwater resources per inhabitant. This may explain a tendency towards lower productivity in this sector. Measured productivity may be further lowered by investments for improving water quality (in line with stricter regulation) and the need to invest more to replace aging infrastructure.

Finally, in terms of the composition (factor inputs) in the growth of value added, we observe that capital rather than labour is the one that has driven the trend of value added growth across the seven countries. The contribution of capital in this growth is especially important in the UK and less relevant (in comparison with labour) in Germany.

Conclusions

The productivity puzzle is present is the individual countries, especially in the UK. There are different reasons that may explain the weakness of the value added TFP growth, including increased investment requirements at a time of flat or falling demand (or rising demand but with insufficient supply in the case of water), driven by wider economic factors or others such as climate change pressures. However, productivity growth especially in electricity and gas sectors may have been negatively affected by the energy transition which has required higher levels of inputs at the same time as competition, regulation and falling demand, which have limited the ability to raise revenues and hence value added. Under these circumstances, recovery in TFP growth for EGW sectors is not expected to happen in the short-term. The EGW sectors need to internalize the changes driven by the energy transition and global warming and to adapt their operation and economics in line with this.

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Attendee Comments

Syahrul Nizam,

PhD Researcher, University of Edinburgh

"Learning from both perspectives, industry and academic point of view has always been my motivation to pursue my interest in the energy sector and for that reason, attending the IAEE conference has allowed me to learn from the experts."

Pricing Patterns in Wholesale Electricity Markets: Unilateral Market Power or Coordinated Behavior?

BY DAVID P. BROWN AND ANDREW ECKERT

David P. Brown and **Andrew Eckert** are members of the Department of Economics at the University of Alberta; dpbrown@ualberta.ca aeckert@ualberta.ca

Overview

Suspicions of coordinated behaviour may arise when firms are observed to be behaving in conspicuous ways that could be designed to communicate with rivals. Indeed, screens that have been employed by or recommended to antitrust agencies to identify possible coordination have looked at price uniformity and rigidity as well pricing anomalies observed in settings where coordination is suspected (Abrantes-Metz and Bajari, 2009). However, the observation of such unique patterns in prices does not necessarily indicate that the patterns are being used to coordinate at supra-noncooperative outcomes.

A recent example highlighting these concerns involves the wholesale electricity market in Alberta. Until recently, the complete list of firms' wholesale market bids was made public approximately ten minutes after the market cleared, but with generator and firm identifiers removed, through the Historical Trading Report (HTR). In 2013, Alberta's Market Surveillance Administrator (MSA), issued a report alleging that certain large firms were using the HTR to elevate market prices on certain days (MSA, 2013). Part of the MSA's concern was the allegation that firms were "tagging" offers, or employing certain patterns in offer prices, in order to reveal their identities through the HTR and to send messages. These concerns led to a hearing of the Alberta Utilities Commission (AUC) in 2017, which ordered the system operator to cease publication of the HTR (AUC, 2017).

There is a growing debate over the role of market transparency in wholesale electricity markets. In a static oligopoly setting with non-cooperative firms, existing literature suggest that information enhances market competition (Holmberg and Wolak, 2018). Alternatively, in a setting where agents interact repeatedly, it has been argued that information can help facilitate coordination (von der Fehr, 2013). Concerns over coordination in electricity markets have been documented in theoretical models [e.g., Fabra (2003)]. However, there is limited empirical evidence of coordinated behaviour in electricity markets. Two exceptions are Macatangay (2002) in England and Wales and Fabra and Toro (2005) in Spain. However, these papers do not investigate the role of market transparency in firms' abilities to coordinate on high-priced outcomes.

We build on the existing literature to develop an empirical methodology to examine whether observed offer behaviour in Alberta was consistent with firms unilaterally maximizing expected wholesale (spot) market profits and if firm behaviour differed on days where the tagging patterns were observed in the HTR. Our analysis has important policy implications in the face of recent legislation to increase information disclosure and market transparency in European electricity markets (von der Fehr, 2013).

Methodology

Our primary objective is to empirically evaluate if firms' bidding behaviour is consistent with static (unilateral) expected profit-maximization or whether their conduct is better explained as some form of coordinated behaviour. First, it is important to account for the presence of uncertainty in demand and wind output when firms formulate their bidding decisions. Consequently, we establish an empirical model to forecast hourly demand and wind in order to compute the estimated level of net demand (demand minus wind output) and the distribution of its residuals to capture market uncertainty. Second, for each hour, we construct a firm's residual demand curve by taking the estimated net market demand level and subtracting a firm's rival's observed offers to establish a downward sloping residual demand function. To account for the presence of demand and wind output uncertainty, we undertake a Monte Carlo simulation that randomly draws 1,000 values from the estimated residual distribution of net market demand. This establishes a distribution of net market demand point estimates and consequently, residual demand functions that a firm could face in any given hour.

Third, facing the estimated distribution of residual demand functions, we estimate a firm's expected profit and the distribution of market-clearing prices from employing its observed offer strategy. Fourth, we construct an array of counterfactual offer curves to investigate if several large firms could have employed alternative offer strategies to elevate their expected profits, and whether the profitability of unilaterally deviating was greater on days where unique tagging patterns were observed.

Results

We focus on two firms that were the subject of concerns raised by the Alberta Market Surveillance Administrator. We illustrate that these firms alter their offer behaviour in on-peak hours when unique offer patterns were observed in the HTR. More specifically, these firms elevated the offer prices on their coal and natural gas generation units often establishing a high-priced shelf in the market-level offer curve. We do not observe similar systematic responses by other large firms.

Our analysis finds that one of these firms could have unilaterally increased its expected profits through deviations that involve reducing offers on its high priced units. The potential gains in its expected profits are pronounced on days where it employed its unique offer pattern resulting in increases of up to 15% in its hourly expected profits. These expected profit gains exceed even conservative estimates of ramping and startup costs. This rules out the explanation that the firm was pricing out its generation units to avoid these dynamic costs.

For the other firm of focus, results are less clear; while deviating optimally could unilaterally increase its expected profits, such deviations are complicated and involve both increasing and decreasing offers depending on circumstances. Further, there is limited evidence that the profitability of deviating is greater on days in which pricing patterns are employed. Our results are consistent with a firm taking a leadership role to increase market prices in certain hours.

Conclusion

A difficulty in cases involving an allegation of coordinated behaviour is that suspicious conduct observed by firms suspected of coordination may have other explanations. As a result, it is important that in such cases an analysis be carried out to investigate whether observed conduct is consistent with unilateral profit maximization, or is better explained by a theory of coordinated behaviour. In this paper, we carry out such an exercise in the context of Alberta's wholesale electricity market, in which the industry's monitoring agency had accused certain firms of setting prices designed to convey information to rivals and to signal intentions regarding future behaviour.

Overall, our findings provide support for the concern that tagging patterns may be associated with bidding that deviates from non-cooperative equilibria. In particular, for one of the large firms of interest, we find that it could have elevated its expected profits by up to 15% in certain hours by pricing in its tagged generation units.

In the face of increased renewable generation resources, there is a recent movement to increase market information and transparency to better manage renewable resource intermittency and facilitate more accurate price forecasts for market participants [e.g., see EU (2013)]. However, our findings provide support for concerns that detailed near real-time information on firms' bids can be detrimental to market competition in concentrated wholesale electricity markets where firms interact repeatedly. In addition, attempts to de-identify data published in near real-time may not be sufficient to alleviate concerns over the use of market information to facilitate coordinated behaviour.

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IAEE Student Chapter Leaders Meeting

BY PABLO BENALCAZAR, IAEE STUDENT COUNCIL REPRESENTATIVE

On the 31st of March, the IAEE Student Chapter Leaders Meeting was held on the premises of the HEC Montréal. During this meeting, IAEE's Student Council Representative, Pablo Benalcazar provided an update to all delegates on the student activities sponsored by or involving the IAEE and encouraged student chapters to promote their activities online on social media by mentioning @IA4EE. IAEE Student Chapter Leaders discussed the development of a Student Chapter Manual, intended to serve as a general guide for current and future student chapter officers on the administration of IAEE student chapters. The meeting also held discussions on additional services and new ideas to strengthen the collaboration among student chapters, keep current student members engaged, retain former student members and increase the visibility of the IAEE community.

Electricity Simulations on the Distribution Edge: Developing a Granular Representation of End-User Electric Load Preferences using Smart Meter Data

BY ASHWINI BHARATKUMAR, RICARDO ESPARZA, KRISTINA MOHLIN, ELISHEBA SPILLER, KAREN TAPIA-AHUMADA AND BURCIN UNEL

The authors are affiliated with the Massachusetts Institute of Technology Energy Initiative; Environmental Defense Fund and institute for Policy Integrity at New York University School of Law. Corresponding author: Kristina Mohlin: kmohlin@edf.org

Introduction

The electric distribution grid is transitioning toward a model in which customers can themselves provide a variety of services to the grid by investing in distributed energy resources (DERs) such as distributed solar generation, programmable appliances, and energy storage. However, customers' incentives to make these investments depend on how they are being charged for electric service. Specifically, the way the electric distribution company allocates the cost of service into the different elements of the rate (tariff) design, such as volumetric or demand charges and time-variant or flat charges, determines the returns on investment for different types of DERs. The rate design will also be a main factor in determining how, when, and where DERs are deployed and used, and whether DERs will contribute to improving system reliability and reducing electric system costs.

Despite the topic's importance for the electric distribution system of the future, the body of literature on the impact of electric rate design on the proliferation of DERs is still limited, see e.g., Darghouth et al. (2016), Hledik and Greenstein (2016), Schittekatte et al. (2018), and Simshauser (2016). Though these studies look at important topics such as the potential for cost shifting, they all hold electricity consumption patterns constant, and, hence, do not take into account how customers' use of electricity may shift in response to new electric rate designs. As a result, their approaches are more limited in their ability to capture the impact of rate design on the return on investment for different DERs.

Our research improves upon common assumptions of fixed electric demand by incorporating microeconomic theory into an existing engineering simulation model. Typically, engineering simulations model a cost-minimization problem with an ad-hoc monetized penalty for deviations from a reference electricity use profile, and, thus, do not provide a very good representation of consumer preferences. In contrast, by including preference parameters that are calibrated to data from observed electric customers, we can more accurately represent how residential customers would respond to different electric rate designs through consumption shifting, conservation, and DER deployment.

Methods

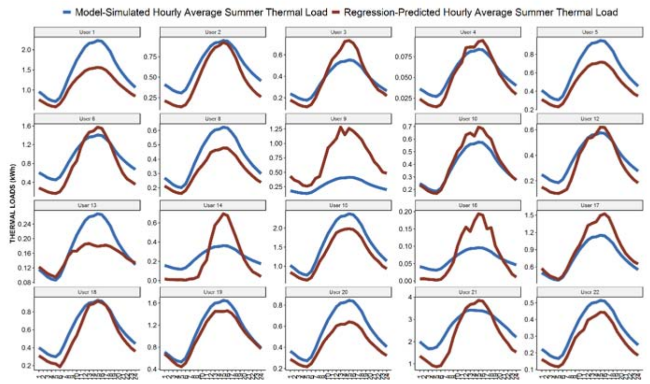
Specifically, we replace the ad-hoc penalty in an electric bill minimization model with a consumer welfare (i.e., an economic utility) constraint to represent consumer preferences for electric services. This specification allows us to separate consumer preferences related to thermal (heating and cooling) needs, which are weather-dependent, and other electricity services, which depend on individual preferences for appliance usage. We then calibrate the model using hourly AMI data for over 50,000 customers of a large US electric distribution company. The calibration methodology first conducts a regression analysis of observed loads on outdoor weather and other control variables to estimate household-specific thermal electricity loads; non-thermal loads are calculated as the difference between observed total loads and estimated thermal loads. We then calibrate the parameters of the utility constraint such that the model replicates the daily load shape of the regression-estimated non-thermal electricity loads, and adjust the parameters representing building thermal properties to replicate the regression-estimated cooling loads.

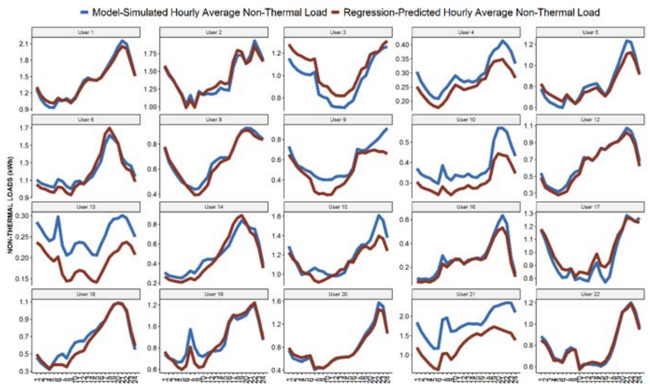
Results

The two figures on the next page illustrate the average model-generated load shapes across the hours of the day and compares them to the average load shapes estimated in our regression analysis. We plot the model-simulated and regression-estimated summer average space cooling loads in the top graph, with the respective yearly average non-thermal loads in the bottom graph. The figures show that, in general, our household-level calibrations allows the model to closely replicate both space cooling loads and non-thermal electricity loads for each household in our random sub-sample.

Conclusions

The results of this research demonstrate the capabilities of our modelling tool for creating large numbers of synthetic end-user profiles that can replicate observed household level load data, relying on a combination of econometric techniques and engineering simulation methods. In future research, we will further improve the calibrations, and then use the





resulting individually calibrated preferences to assess how end-users may respond to different electric rate designs by changing their electricity load and investing in DERs.

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Dual Plenary Session 3: New Business Models: Prosumers and Future Grids

SUMMARISED BY PALLAVI ROY, PHD GRADUATE, RYERSON UNIVERSITY

Plenary 3 was titled New Business Models: Prosumers and Future Grids. New technologies are evolving and challenging old business models, while also creating opportunities for new business models to flourish. The 3rd plenary tackled the topic of new business models, discussing a vast range of topics that are impacting the current grid and exploring key elements of future grids. Jorgen Bjorndalen from DNV GL chaired the session. Main speakers were Hugues Giradin, representing Canadian wind company Boralex, Marc-Andre Forget of OSSIACO, a Canadian energy services company (ESCO) and Dr. Hans Auer from Vienne University of Technology.

The main focus of the discussion was the disruption in the power sector and consumer-focused innovation. Considerable emphasis was placed on the customer and their evolving needs. New modular generation technologies are empowering consumers to become prosumers and are seeing rapid adoption in many jurisdictions such as Germany, Australia, California, among others. The need for grid flexibility was stressed upon by all panel members. New technologies such as electric vehicles, battery storage are all adding critical complexity to the power grid, which in turn is creating new opportunities. Many new ESCOs are developing services and products to cater to customers' demands while utilizing new innovative business models.

Mr. Giradin compared the power sector disruption to the once faced by the telecommunications sector in the 2000s. Telecom industry too saw a move from wired connections to wireless technology which completely modified the business model. The telecommunication sector example identifies that the winners in this disruption will be power sector organizations that explore new ideas and offer customers new services. Mr. Forget declared that “We are counting down to a global energy revolution”, which is expected to see increased adoption of distributed generation technologies leading to the rise of prosumers and bi-directional exchange of energy with the grid. Dr. Auer remarked that power sector utilities need to focus on their customers more and provide a suite of services and products to meet evolving customer needs.

The unintended consequences of these developments (increasing distributed generation) such as stranded assets and impact on low-income customers were also discussed. It was agreed upon by all panel members that the evolving grid requires new policies to make a sustainable transition to a future grid. New policies are required allowing the power sector to evolve in ways that optimize new technologies, putting the consumer at the centre of new business models.

The Welfare and Price Effects of Sector Coupling with Power-to-gas

BY MARTIN ROACH AND LEONARDO MEEUS

Introduction

Sector coupling has been given increasing attention in EU policy debates. One study states that sector coupling can substantially reduce the costs of the transition to a decarbonized system through the use of existing energy infrastructure, including gas networks and storage facilities, which can reduce the additional capacity needed in electricity transmission and distribution grids (EU Parliament). The challenges associated with evacuating RES generation will increase with higher renewable energy targets.

Power-to-gas (PTG) has been identified as a technology capable of producing carbon-neutral or carbon-free gases to decarbonize the gas sector and provide demand flexibility to the power sector. The two conversion processes associated with PTG are hydrogen production by electrolysis of water and synthetic methane production by methanation, in this study we only consider the former. Some industry studies highlight that the production of hydrogen produced via PTG using renewable electricity will depend on major production cost reductions primarily driven by electrolyzers and access to cheap renewable electricity (Gas for Climate).

Many academic studies have focused on assessing either the economic potential or technical feasibility, but few such as Vandewalle et al. (2018) have explored challenges related to cross-sector market coordination and incentives. If the support for PTG from the electricity and gas sector actors diverges due to the impact that PTG presence may have on the redistribution of welfare across sectors, then investments in PTG may never materialize.

Method

The aim of this paper is to study the PTG investment decision in a context which has perfectly competitive agents in the electricity and gas market, each market is cleared separately but coupled by PTG. We study the welfare distribution and price effects at sector optimal capacities of PTG to know if we can expect a cooperative or non-cooperative long term equilibrium in the electricity and gas sector. Inspired by other sector-specific Mixed Complementarity Problem (MCP) models, we propose a stylized long-term equilibrium model using a MCP formulation (Gabriel et al., 2013). We solve the model using PATH in GAMS.

The electricity market has generators maximizing profit, subtracting its variable costs (VC) and investment costs (IC) from market revenues. Two conventional and one renewable (RES) generator, with 100% and 30% availability factors, respectively, participate in the market. An inelastic demand is represented by a Load Duration Curve (LDC) taken from Joksow et al. (2003) of 10 periods, each period has 876 hours. Each period simulates representative hours. The instantaneous balance between supply and demand and ramping constraints are not represented. As in Saguan et al. (2019), a renewable electricity target in the market clearing constraint imposes that a percentage of gross consumption must be satisfied by RES. This constraint drives a capacity-based premium paid by electricity consumers and paid to RES generators to support investment recovery in order to meet the RES target. Maximizing electricity welfare consist of minimizing energy market and premium costs.

Martin Roach (Martin.roach@vlerick.com) is a Doctoral Researcher at Vlerick Business School and a PhD student in Business Economics at KU Leuven. **Leonardo Meeus** is the Director of the Energy Centre at Vlerick Business School and Professor at the Florence School of Regulation at the European University Institute.

Similar to del Valle et al. (2017), shippers maximize profits by accessing their portfolio of Long Term Contracts (LTC) at a cost determined by a procurement cost function and selling it at the price on the gas market. Elastic gas plants and inelastic gas consumers participate in the market in the same 10 period structure, and are not subject to any RES subsidy costs. Maximizing gas welfare consist of minimizing energy market costs.

PTG is the perfectly competitive market coupling agent with the objective of maximizing profits, earning revenues from the arbitrage between markets at a conversion efficiency and subtracting its VC and IC. The main sensitivities driving the model results are PTG investment costs and the electricity RES target. We annualize investment costs for a range of PTG technology costs: 0, 200, 500 and 1000 €/kw. Each combination of RES target and PTG annualized investment cost form a single scenario to analyse the impact of PTG on electricity and gas markets. For each scenario, in iterating from the baseline of 0 MW of PTG capacity by increments of 50 MW, we obtain a frontier of perfectly competitive outcomes representing the long-run equilibrium points of all agents. For each agent, we measure the positive or negative welfare change of each equilibrium point relative to the baseline. This grid search for agent-specific welfare and total system welfare equilibrium points confirm whether cooperative or non-cooperative behaviour is present.

Results

PTG plays an important price-setting role in the electricity market. Following its short term zero profit condition in each period, PTG consumes RES spillage when the electricity market price is 0 €/MWh, converts it with an efficiency loss and subsequently injects the produced hydrogen into the gas system at the gas market price, when profitable. In a given period, if there is sufficient PTG capacity installed to absorb all of the spillage, the electricity price is determined through this zero profit condition. For example, when the spillage is absorbed in that period, if the gas price is 20 €/MWh and the conversion efficiency of PTG is 80%, then the electricity price becomes 16 €/MWh. PTG puts a value on the zero marginal cost generation, based on this inter-fuel arbitrage. However, through this price-setting role, PTG also erodes its arbitrage profits. As more PTG capacity is installed, the arbitrage opportunity disappears in more periods.

In our stylized setting, PTG is only installed in scenarios where RES targets are high enough to cause spillage and subsequently limited by PTG investment costs. PTG can have a positive impact on total system and sector welfare, and we do not observe a divergence in incentives to install PTG. In participating as a new supply source in the gas market, PTG places slight downward pressure on gas prices benefiting gas consumers. PTG improves the capacity factor of renewables through the absorption of spillage and creates non-zero electricity prices for the spillage consumed. From this price-setting behavior, RES generators are less dependent on out-of-market capacity-based premium to recover their IC. As a result, electricity consumers pay higher prices compared to the baseline, but gain more from the reduction in premium costs paid to RES generators.

The installed capacity of PTG is optimized in a stylized setting, so a complimentary sensitivity analysis exposes how the sizing of PTG and resulting welfare benefits can vary under the same RES targets. In short, the availability factor of renewables and the LDC characterize an electricity system which ultimately specify when spillage occurs and how much. The added value of PTG depends on the electricity consumer costs associated with meeting RES targets across these sensitivities which can be cross-compared.

Conclusions

PTG plays a price-setting role in the electricity market, but this also erodes its arbitrage profits as more PTG capacity is installed. The system optimal PTG capacity leads to positive welfare gains in both the electricity and gas system, when installed, therefore non-cooperative behavior due to diverging incentives is limited. A sensitivity analysis highlights the stylized nature of the model, which reconfirms limited non-cooperative behavior but demonstrates optimal PTG installed capacities can vary based on system characteristics.

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Dual Plenary Session 4: Liquid Fuels and Transportation

SUMMARIZED BY YORMY ELIANA MELO POVEDA, PHD STUDENT, FEDERAL FLUMINENSE UNIVERSITY

This plenary session was chaired by Ron Ripple, University of Tulsa. He was joined by Adam Sieminski, from KAPSARC; Denis Arguin, from Enerken, and Sagar Kancharla, from WSP.

The session focused on biofuels, electric vehicles and the future perspectives for oil-based products. The speakers presented the possibilities and challenges of gaining access to cleaner transportation.

Denis Arguin provided deep insight about the Enerkem company. He pointed out that Enerkem is the World's first commercial facility in converting household waste into clean biofuels and green chemicals, such as ethanol and methanol. While Enerkem is located in Edmonton, Canada, it has a detailed expansion plan towards the rest of the world. The presentation showed that Enerka is an excellent innovation model of the sustainable transportation and managing waste.

Sagaar Kancharla presented the repercussion of electricity vehicles transportation. Likewise, he built comparisons with the transportation fuels: high low carbon fossil fuel, low carbon fossil and no carbon fossil fuel. He stressed that the share of EV in transportation is small. He highlighted that EV infrastructure needs to be developed through an integrated coordination between policy makers, automakers, regulators, utilities and consumers. Moreover, competition has an important role to play in the EV infrastructure.

On the Relationship between Policy Uncertainty and Investment in Renewable Energy

BY KELLY BURNS

Introduction

Investment in renewable energy globally has been declining in recent years and the International Energy Agency (I.E.A.) is concerned this trend will inhibit our capacity to meet climate change objectives (I.E.A., 2018). While there exists some empirical evidence about the drivers of renewable energy supply and demand, we know little about the drivers of investment in renewable energy. In this study, we consider the impact of policy uncertainty on investment in renewable energy in the USA.

Uncertainty & Investment

Policy uncertainty represents a significant risk for investors and is a fundamental consideration when assessing the profitability of investment decisions (Bernanke, 1983). Anecdotal evidence suggests that policy uncertainty relating to carbon emissions reduction, renewable energy and fossil fuels detrimentally affects the level of investment in renewable energy (see, for instance, Ritter, 2018; Harrabin, 2016). Several surveys support the proposition that investors perceive Renewable Energy Investments (REIs) as carrying greater risk (reflected in higher weighted average cost of capital) due to risks stemming from policy uncertainty (see, for instance, Eryilmaz and Homans, 2013). However, no empirical evidence exists to either support or refute this hypothesis. This study aims to fill this gap in our knowledge base by enhancing our understanding of how Energy Policy Uncertainty (EPU) influences REI. The findings will help support policy-making geared towards energy transition, energy security and environmental objectives (including reducing greenhouse gas emissions and decarbonisation of the global supply chain).

Policy changes & the news

We begin by considering the policy environment in the USA and how this relates to the publication of energy policy related articles. From 2009 to 2015, there were a total of 85 energy policy changes in the USA. Of these, most related to climate change (52%), followed by energy efficiency (29%) and renewable energy (19%). Most policy changes relating to climate change and renewable energy were the introduction of new policies ("in force"), accounting for 65% of policy changes over this period. Existing policies that were "superseded" or "ended" accounted for 17% each over the sample period (33% combined). Since 2009, the introduction of new climate change and renewable energy policy changes in the USA has declined significantly (12 in total were introduced from 2011 to 2015, compared to 17 and 10 in 2009 and 2010, respectively). Over the same period, the number of energy related articles published in the 5 leading USA newspapers[1] has also declined substantially, from a high of 549 in 2008 to less than 300 from 2012 to 2015.

Kelly Burns is an Energy Economist and Research Fellow at Curtin University (Australia) and her research specialises in energy modelling, renewable energy and energy policy. She may be reached at drkellyburns@gmail.com

See footnotes at end of text.

As we observe in Figure 1, when the number of energy policy developments rises (falls), the number of energy related articles published in leading USA newspapers falls (rises). This reflects the trend for media speculation and uncertainty in the lead up to, and anticipation surrounding, significant energy policy changes.

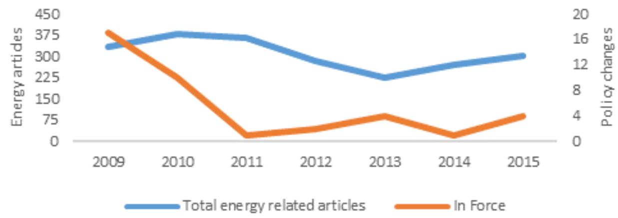

Figure 1. USA energy related articles and policy changes
Source: IEA Policy and Measures database; Burns, 2019

Introducing the Energy Policy Uncertainty Index

A recent advancement in our attempts to better understand and measure the influence of policy uncertainty on REI is the development of an EPU index (Burns, 2019). The index has been developed by adapting the well-known methodological framework proposed by Baker et al. (2015) and provides a measure of news-based policy uncertainty at the country level.[2] To address concerns about the robustness of the EPU index to capture market uncertainty relating to energy policy, we follow the approach of Baker et al. (2016) and apply market analysis techniques to assess whether significant events thought to influence the USA energy policy environment (and may have led to speculation and uncertainty) are captured. We observe that significant peaks and troughs in the EPU index are associated with major energy and emissions reduction policy changes, as well as the USA Federal election (refer Figure 2). This includes the Climate Action Champions Initiative, the 21st session of the Conference of the Parties (COP21) of the United Nations Framework Convention on Climate Change (including the development of Nationally Determined Contributions (NDC)), the Renew300 Initiative and the Clean Power Plan. All four policy events were key pieces of President Obama's Climate Action Plan and were aimed at reducing GHG emissions, promoting energy transition and encouraging private investment in green energy. Based on these observations, it is reasonable to conclude that the EPU index is an appropriate tool to measure EPU in the USA.

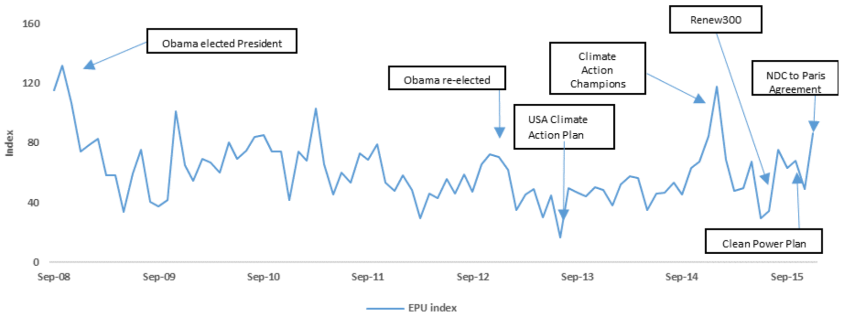

Figure 2. EPU index and energy policy changes in the USA 2008 to 2015

Energy policy uncertainty & investment

Having demonstrated the robustness of the EPU index to capture uncertainty and speculation consistent with significant energy policy changes, we now consider trends and associations between movements in the EPU and REI in the USA[3]. Given the significant amount of volatility in each of the time series, we apply the Hodrick-Prescott filter and decompose both series into trend and cycle components.

As we observe in Figure 3, there is a clear inverse relationship between trends in REI and EPU. Similar to our observations above (refer Figure 1), when the level of EPU rises (falls), the level of REI falls (rises). This is prima facie evidence that EPU influences REI in the USA.

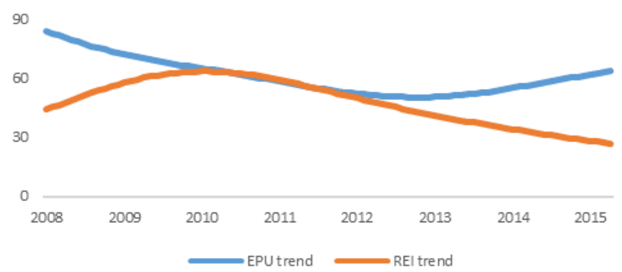

Figure 3. Trend in USA Investment in renewable energy and EPU index

There have been some significant changes in the policy landscape and REI trends in the USA in recent times. To consider and account for this, we apply the Bai-Perron test for 1 to M structural break points and find the following breakpoints for each series: EPU index at 2009M10, 2011M11, 2013M07 and 2014M10; REI at 2009M10, 2012M02 and 2013M06.

There is a striking similarity in the structural breaks identified for each of the series. Importantly, we find contemporaneous breakpoints in October 2009. Interestingly, four significant events occurred in 2009: the inaugural election of President Obama; a record number of climate change and renewable energy policy changes were enacted in the USA; implementation of Executive Order 13514 (Federal Leadership in Environmental, Energy, and Economic Performance); and the ratification of the American Recovery and Reinvestment (ARR) Act. The Executive Order mandated greenhouse gas management as a priority for the Federal government, and introduced detailed targets and reporting requirements on energy use and GHG emissions by Federal agencies. The ARR Act was a supplementary-spending bill containing over USD 80 billion to support clean energy research and development, including USD 277 million for cost-effective alternative energy technologies, USD 6 billion to accelerate the deployment of a range of commercial clean energy technologies and USD 30 billion in tax-based incentives for REIs.

We also find a breakpoint in the EPU index in November 2011, quickly followed be a breakpoint in REI during in February 2012. In 2012, the USA introduced the Africa Clean Energy Finance Initiative. This initiative was a financing mechanism designed to catalyse significant private sector investment in renewable energy infrastructure. Additionally, we find almost simultaneous breakpoints in 2013 that coincide with the re-election of President Obama, the USA Climate Action Plan to cut GHG emissions and the introduction of the Better Buildings Accelerators program (to accelerate investment in energy efficiency). These observations provide evidence that energy policy changes (including the outcome of Presidential elections) coincide with structural changes in REI and EPU.

Concluding remarks

The results indicate there is an association between EPU and REI. We find evidence of inverse contemporaneous trends as well as a lag/lead relationship, consistent with the hypothesis that higher EPU leads to lower REI. We conclude that EPU is an important factor that policy-makers should take into account when attempting to encourage investment in renewable energy. The results make a valuable contribution to our understanding about the drivers of REI and are of particular relevance for policy-making aimed at reducing greenhouse gas emissions, decarbonising the value chain and achieving environmental objectives.

Footnotes

[1] These are New York Post, USA Today, New York Times, Los Angeles Times and Wall Street Journal.

[2] For full details on the methodology used to calculate this index, please refer to Burns (2019).

[3] REI data is sourced from the Bloomberg New Energy Finance database.

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Plenary Session 5: Can Energy Efficiency Foster Energy Access?

SUMMARIZED BY AMOS OPPONG, DOCTORAL RESEARCHER, UNIVERSITY OF ELECTRONIC SCIENCE AND TECHNOLOGY OF CHINA

This session was chaired by Maya Papineau, Assistant Professor, Carleton University, Canada. She was joined by Sebastian Raoux, Ph.D., J.D, President & CEO of Transcarbon International, and Chairman of the Board of Directors – International Experts on Sustainable Development (IESD); Dr Bernie Jones, Project Co-leader, Smart Villages Research Group Limited; and Saide Sayah, City of Ottawa.

Countries around the globe have made giant strides in providing uninterrupted energy supply to various consumers. However a good proportion of developing nations still have significant fractions of their population that have no access to electricity or experience frequent interruptions in energy supply.

Sebastian Raoux gave a comprehensive overview on the strides made with a comparative analysis of access to energy and energy efficiency policies focusing primarily on low income and lower-middle income economies. Despite the strides made, a significant proportion of the world population still lives in remote areas with limited or no access to grid-related energy supply. The access to sustained energy for all development goal demands that energy supply extended to such off-grid areas.

Bernie Jones presented on smart villages as policy options for providing energy to off-grid communities worldwide based on decentralized sustainable development strategies. He mentioned local GSM network and community broadcasting as among the numerous benefits that remote regions could enjoy in a smart village case.

Saide Sayah presented on affordable housing and energy outlook of Ottawa and introduced the concept of Passive Houses [i.e., houses designed and built such that they are endowed with thermal installations, passive house windows, thermal-bridge-free, airtightness and comfort ventilation with highly heat recovery] as potential consideration in future housing projects.

Based on questions from participants, the panel reiterated that advanced countries could learn from, and possibly implement, the new energy modules that have been successfully implemented in developing economies. The panel also stressed on the need for cooperation among various stakeholders and the government in adopting the proposed technologies to reach energy demands for all at little cost to the environment.

Dual Plenary Session 6: Oil & Gas Challenges

SUMMARISED BY THERESIA BETTY SUMARNO, PHD CANDIDATE, UNIVERSITY OF DUNDEE

The oil and gas challenges session was chaired by Ms Amy Myers-Jaffe, Council on Foreign Relations, who was also part of the panel. There are many challenges in the oil and gas, such as from political, technical and geological challenges. She gave a brief introduction about the two other panels, Mr. Michael Binnion from Questerre and Mr. Robert Kleinberg from Columbia University. The discussion was focused on the challenges faced in the oil and gas industry currently. There are different challenges being discussed in the panel, firstly the sustainable and zero emission hydrocarbon, secondly the tight oil recovery production methodology, and lastly is the challenges from the oil and gas demand supply challenges which started by discussing the forecast from OPEC view and how it is related to the industry spending on their investment.

Mr. Michael Binnion from Questerre started the discussion which focused on sustainable hydrocarbon and the oil and gas challenges in the current era of energy transition. In the discussion, Mr. Binnion brought up about the possibility of having a zero-emission natural gas.

Mr. Robert Kleinberg followed the discussion by talking more about the tight oil low technology and high technology. He described the oil recovery production techniques, the primary oil recovery, secondary oil recovery and the tertiary oil recovery. These three recovery techniques are basically the tool box for the production of conventional oil. In the tight oil recovery, there is no primary, secondary nor tertiary recovery oil technology and it is required high technology for producing the tight oil which is very expensive. The high tech is by injecting gas into individual wells, then re-pressurized it, and then stop injecting and start producing the oil.

The last panel was brought by Ms. Myers-Jaffe. She was discussing on the oil and gas challenges from the OPEC point of view. The challenge is more about balancing the market, and how the U.S. contribute in meeting the demand. There is a flexibility, as when there is a higher price, they would produce more oil.

She mentioned that the ability of the NOC is to maintain the budget and capital to spend in their activities. People were only aware on how much capital the oil companies spent in their project, especially the private oil companies.

Plenary Session 7: Load Profile Challenges and Energy Storage

SUMMARIZED BY ELEANOR MORRISON, PHD STUDENT, SOAS – UNIVERSITY OF LONDON

This plenary session was chaired by Ramteen Sioshansi, Ohio State University. He was joined by Dr. Karim Zaghib, General Director for the Center for Excellence in Transportation Electrification and Energy Storage at Hydro Québec; Ben Haley, Co-Founder at Evolved Energy Research; and Martin Larocque, President of Sigma Energy Storage.

This plenary session conducted on the final day of the conference presented the scope of energy storage technologies available and discussed the advancements in commercial viability. Whilst the panel referenced the Quebec and North American electricity grid environments, applications to markets with no centralised transmission grid structure, such as parts of Africa, were discussed.

Referencing extensive Lithium Ion battery technology research, Dr. Zaghib emphasized the need for utility companies to focus on the different applications for energy storage and the benefits for substation peak shaving. Ben Haley presented his view on the expected future state for implementation of energy storage and mentioned that alternatives to battery storage methods could be more economical on long term requirements. The background and potential for Compressed Air Energy Storage (CAES) was presented by Martin Larocque. In a CAES system, ambient air is compressed and stored under pressure in an underground cavern with a suitable geology structure. When electricity demand requires more energy to the grid, the pressurized air is heated and expanded through an expansion turbine that drives a power generator.

The session concluded with agreement amongst the panel members that it is critical to understand the needs of the electricity load system to find the best technology for the solution whether it be battery storage or alternative technologies such as CAES.

On Optimal Extraction under Asymmetric Information over Reclamation Costs

BY PAULI LAPPI

Motivation

Currently, a problematic feature of exhaustible resource production in many countries in the world including the U.S. and Canada is that there is too little funds for reclamation of the production site.[1] This means that either tax payer money must be used for reclamation or the reclamation is not properly conducted, which may result in environmental problems such as acid mine drainage, loss of forests, grasslands and recreational benefits. The regulator, who would like to save public funds and improve the state of the environment, does not know the future reclamation costs, and must often ask the firm to report them. But the firm cares about its profits, and has incentives to misreport. The regulator must take these incentives into account when it offers a contract to the firm.

Research questions

The focus is on the optimal regulation of a polluting exhaustible resource firm, whose extraction generates a valuable good and a stock pollution that causes environmental damages. The stock is regulated with a pollution tax designed for an optimized production horizon and with a reclamation requirement at the end of production, where a part of the stock is reclaimed. The regulation is designed under firm's private information over the reclamation costs and the main research questions are:

1. How should the regulation be designed to obtain maximal benefits for the society from the extraction operation, when the firm has private information over reclamation costs?
2. What kind of properties does the optimal regulation have? In particular, how is the pollution tax affected by private information?

Model

These questions are analyzed using a two-stage model, where extraction stage is followed by reclamation. Many pollutants related to exhaustible resource extraction are stock pollutants, like the pollutants in the tailings ponds in oil sand extraction (Heyes et al. 2018), and they are accumulated on or nearby the extraction site. It is this stock that forms the object to which the reclamation operations are targeted. Without regulation the pollution stock is not reclaimed at all, which means that the pollution stock and the production horizon are sub-optimal from the society's point of view. To avoid this possibility, the regulation in the paper's model consists of an optimal pollution tax on the extracted good, an optimal shut-down date for the extraction operation, a requirement for the firm to pay the present value reclamation costs before extraction commences and an optimal reclamation contract.

Pauli Lappi is Marie Sklodowska-Curie fellow at Ca' Foscari University of Venice and CMCC Foundation - Euro-Mediterranean Center on Climate Change, Italy. E-mail: pauli.lappi@unive.it.

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See footnote at end of text.

To find out the relevant properties of this regulation, the model is analyzed backwards beginning from the reclamation stage. The regulator wants to induce the firm to choose an optimal reclamation effort, that is, the effort that maximizes the net social benefits given the inherited pollution stock from the extraction operation. The complication is that the regulator does not know the size of the reclamation costs, but the operating firm knows them. Because the firm is required to pay the present value reclamation costs to the reclamation fund or trust (or as a bond), he has incentives to say that the costs are high in order to make the effort low and the payment to the reclamation fund small. This means that the regulator has to design a mechanism to induce truth-telling about the reclamation costs. In the extraction stage, the regulator wants the firm to choose the socially optimal extraction rate while understanding how the reclamation stage optimum depends on extraction stage choices.

Results

The reclamation contract consists of reclamation effort and transfer payment to the firm. It is found that optimal second-best reclamation effort deviates from the first-best reclamation effort, that is, from the optimal effort without information problems. This deviation is increasing in the cost-type of the firm, and the optimal contract dictates the lowest reclamation effort for the highest-cost type firm. This contract is also designed in a way that the monetary transfer for the highest-cost firm type equals the difference between the reclamation cost and the (current value) extraction profits; in other words, it extracts all of the profit from the highest-cost type firm. The contract leaves positive profits for the more efficient firm types.

Regarding the extraction stage regulation, it is shown that the extraction decision is distorted away from the first-best solution. Furthermore, given the reclamation contract, an optimal shut-down date and optimal pollution tax are characterized. In particular, a waiting rule and a pollution tax formula are derived, and it is shown that the pollution tax under asymmetric information can be lower or higher than the pollution tax under complete information. This is intuitive: suppose for example that the firm's reclamation cost is low so that any pollution stock generated can be cheaply reclaimed. If the regulator knows this, he can allow higher pollution generation compared to the case where the cost is private information. But under asymmetric information the regulator bases his tax decision on expected values and must constrain the pollution generation with a higher tax compared to the complete information case.

In addition, it is possible that the regulator may wish to exclude some firm types by not offering them a contract at all. More specifically, this can happen to those types who have high enough reclamation costs. The cut-off type is the type for which the society's total present value of extraction payoff equals the present reclamation stage value. Every extraction firm with a cost type higher than the cut-off value should not be allowed to extract the resource.

Conclusions

Taking into account firm's private information over reclamation costs and designing the optimal reclamation contract and the regulation can yield three kinds of benefits:

1. It can save public funds since the reclamation operation does not fall on the society;
2. It improves the state of the environment;
3. It allows to exclude those cost types whose extraction operation would not produce benefits for the society.

However, the relevant information problems do not stop at reclamation costs. Exhaustible resource producers often have private information regarding other parameters of the extraction operation, such as extraction costs (Gaudet et al. 1995, Osmundsen 1995) and initial resource stock (Osmundsen 1998, Martimort et al. 2018). Furthermore, in practice, even the firm may have difficulties estimating these parameters. These dimensions should also be taken into account, when designing optimal regulation.

Footnote

[1] In British Columbia, the shortfall is estimated to be over one billion (Hoekstra 2017). The problem is at least as severe in the U.S. coal sector: According to an actuarial report for the West Virginia Department of Environmental Protection and Olalde (2018), the bond amounts in the state add up to about total $150 million or $3,200 per acre (bond limit for new permits is $5,000), but reclamation costs are estimated to range from $7,840 to $28,460 per acre. In Alberta, the amount of securities is about $1 billion, which is significantly short of the estimated $20.8 billion reclamation cost (Heyes et al. 2018)

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Dual Plenary Session 8: Carbon Markets

SUMMARIZED BY JUSTIN LARSON, PHD STUDENT, RESEARCH ECONOMIST AT RTI INTERNATIONAL

Ian Parry presented on the impacts of carbon pricing and the tradeoffs associated with other approaches. In his presentation, Ian showcased results of a spreadsheet model that calculated the costs and benefits of a carbon price policy. Additionally, Ian discussed complements to a carbon price policy as well as potential substitutes. The choice of type of policy, or mix of policies, also varied from country to country.

Augusta Wilson discussed the legal barriers and implications in the United States of linking a carbon market (i.e. RGGI) to other markets abroad. The potential legal conflicts exist at the constitutional level but have yet to be acted upon, despite the linkages between California's cap-and-trade program and the WCI. Moving forward, state legislators will need to be mindful of the potential implications at the Federal level of linking carbon markets.

Onil Bergeron continued the discussion on linking of carbon markets, with a focus on Quebec's cap-and-trade program. In his discussion, Onil detailed the process of linking, the obstacles markets face in linking, as well as the benefits and reasons for linking markets.

After the presentation, questions were fielded from the audience. Questions shared a common theme, feasibility. Given the political hurdles carbon price policies face, what policies or mix of policies are political feasible?

Closer to One Great Pool? Evidence from Structural Breaks in Oil Price Differentials

BY MICHAEL PLANTE AND GRANT STRICKLER

Both authors are affiliated with the Federal Reserve Bank of Dallas. **Michael Plante** is a senior research economist (michael.plante@dal.frb.org). **Grant Strickler** is a Research Analyst (grant.strickler@dal.frb.org). The views in this paper are those of the authors and do not necessarily reflect the views of the Federal Reserve Bank of Dallas or the Federal Reserve System.

See footnote at end of text.

Morris Adelman famously wrote in 1984, “The world oil market, like the world ocean, is one great pool.” If this were literally true, all crude streams would be perfectly substitutable for one another and we would expect price differentials between different crude streams to generally be small, reflecting mainly transportation costs.

Instead, one often observes large price differentials between crude streams, particularly those of different qualities. These quality differentials are important for many oil market participants, including refiners, oil producers, fiscal authorities, as well as academics and analysts interested in understanding the workings of the oil market.

The main question of interest in our paper is whether the average values of such quality-related differentials have declined over time. That is, has the oil market become closer to one great pool in the sense that prices have become closer to each other?

To answer this, we construct price differentials between numerous crude oils of different types and then test whether these differentials have experienced shifts in their means using a structural breakpoint test.

Motivation for this exercise is provided in Figure 1, where we plot one example of a differential between a higher and lower grade crude. Visually, there is strong evidence of at least one break in the mean, occurring sometime around 2007 or 2008. Many other quality-related differentials, not shown here, share this feature.

Crude oil properties and price differentials

The two main physical characteristics of a crude oil are its American Petroleum Institute gravity (API gravity), which measures density, and its sulfur content. Both features vary between crude oils, and both are the main drivers behind the differentials. The industry labels a crude oil as light, medium or heavy based on its API gravity; sweet or sour based on its sulfur content.

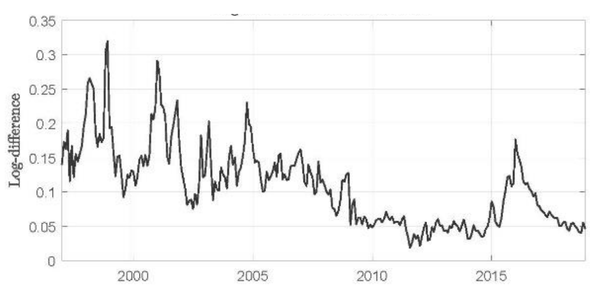

Figure 1. LLS-Mars Differential

There is a hierarchy of quality in terms of density, with light at the top and heavy at the bottom; in terms of sulfur content, from sweet crudes to sour ones. Prices follow the same order—with light-sweet crudes usually selling at a premium and heavy-sour crudes at a discount. The premiums attached to light-sweet crude oil versus a heavy-sour crude, for example, can be substantial, at times exceeding 30 percent.

Light-sweet crude commands this price edge for two reasons. When distilled—the first step of processing any crude oil—it yields a large percentage of high-value petroleum products, such as gasoline and diesel. Denser oils (medium and heavy crudes), on the other hand, yield less of those products when distilled and more of what is, essentially, residual fuel oil, a low-value product mostly used to fuel ships. Gasoline and diesel typically command a hefty premium to residual fuel oil.

The second reason for light-sweet crude’s premium is due to sulfur content and government regulation. Sulfur is a pollutant, and many countries impose strict requirements on how much sulfur is allowed in petroleum products. Light-sweet crude has low sulfur content and requires less processing to remove sulfur than sour crude.

The discount placed on low-quality crude creates a potential arbitrage opportunity for anyone with a way to transform residual content into higher-value products. This is where complex refineries come into play. They possess specialized equipment, generically known as upgrading or secondary processing units, which enable production of more gasoline and diesel from a given barrel of low-quality feedstock. The most complex refiners processing a heavy crude can often produce as much gasoline and diesel as many simpler refineries can with more expensive, high-quality crude oil.

Data and Method

We construct pairwise log-differentials using 14 daily price series from 1997 to 2018. The use of log-differentials has the advantage of converting units to percent differences. We consider differentials between crudes of different qualities as well as those of similar quality. In order to determine the number and timing of breaks, we use the sequential breakpoint test of Bai (1997)[1].

Results

We first focus on differentials of crude oils of different types. A large number of these quality-related differentials—26 out of 27 cases, to be exact—experienced a break around 2007 and 2008. In most of those cases, there has been a large reduction in the mean, often accompanied by a major drop in volatility. The means and volatilities are often half their pre-break levels.

We next investigated whether oil price differentials between crudes of the same type, for example, two light-sweet crude oils, have experienced a similar set of breaks, particularly around 2008. If that were true, it would suggest a broader change in the oil market not necessarily connected to quality. Overall, we do not find any evidence for this.

Finally, we also document that differentials between high-valued petroleum products, i.e. gasoline and diesel, and low-valued residual fuel oil have experienced breaks of a similar nature to the quality differentials around 2008. The breaks result in a significant decline in the mean value of the residual fuel oil differentials.

Explanations

We consider four factors that could potentially explain our findings: a shift toward greater demand for residual fuel oil; a weakening of government regulations on sulfur emissions; a greater amount of upgrading capacity; and the shale boom.

It is quite easy to rule out shifts in consumer demand for residual fuel oil and government regulations on sulfur emissions as potential explanations. In fact, these two forces should be contributing to larger quality differentials. Data from the International Energy Agency show that since 1997, demand for lighter products, such as gasoline and diesel, has boomed by 19 million barrels per day (mb/d), a 28 percent increase, while residual fuel oil use has declined by 4 mb/d, a 37 percent decline. Government regulations on sulfur emissions have tightened as well.

One factor that can explain our findings is the continued global buildup of more complex refineries. By one measure, upgrading capacity has increased by 69 percent over 17 years.

Another important factor is the U.S. shale oil boom, which has unexpectedly boosted the supply of high-grade, light crude oil. By the end of 2018, U.S. light tight oil production had increased to 7.4 mb/d, 6.7 mb/d higher than it was at the start of 2010. This unexpected boom has reduced, on the margin, the need for more complex refineries to process low-grade crude oils.

Footnote

[1] Bai, J. (1997). Estimating and Testing Linear Models with Multiple Structural Changes. Econometric Theory, (13), 315-352. https://doi.org/10.1017/s0266466600005831.

Closing Plenary Session: How to Align Energy Transition with Climate Objectives?

SYMMARISED BY: SUMMARISED BY PALLAVI ROY, PHD GRADUATE, RYERSON UNIVERSITY

The closing plenary was chaired by Mr. Christopher Bonnery, the 2019 IAEE President. Mr. Bonnery introduced the Keynote speaker Professor Weyant from Stanford University, who started his speech by pondering on the question “How to align energy transitions with climate objectives?” The answer to this question, according to professor Weyant, is “Carefully and with great humility”.

Professor Weyant further broke the question down to three main questions that require careful consideration:

1. What should our climate objectives be?
2. What role should energy sector transition play in achieving these goals?
3.How should we allow/cause these transitions to occur?

Furthermore, Professor Weyant emphasised that economics plays a significant role while attributing the impacts and calculating the risks of climate change. He referred to his previous work with the IPCC focusing on the economics of climate change policy, seeking to answer the question “what policy instruments are required for containing climate change?” He discussed nuances related to the choice of frameworks, data availability, assumptions and the scope of economic research which can provide answers to questions such as: Are we aiming for a 2-degree rise or 1.5-degree rise in temperature? What are the different impacts? What is the economic impact? What policy instruments and architecture should we use?

After Professor Weyant’s speech, the focus was put on the past IAEE presidents on the panel. The panel was made up of Professor Peter Hartley (IAEE President 2015), Professor Andre Plourde (IAEE President 2007) and Professor Ricardo Raineri (IAEE President 2017). They were all asked to reflect on the conference in their year and identify how the conference topics and main concerns have evolved. The past presidents from various years remarked that the discussion on the topic of energy sector transition is new and was not as much of a focus in the previous years. While in the 2000s the discussion focused mainly on electricity sector de-regulation, over the past decade the conversation has moved on to low carbon fuels, and natural gas has seen heavy focus at IAEE conferences over the past few years. It was interesting to hear how the pressing energy sector issues have evolved over the past decades, and we look forward to seeing how it evolves in the future, influencing local energy and global markets.

Interviews

Interview with John W. Jimison – IAEE General Counsel, Winner of the Outstanding Contributions to the IAEE Award

In 1977 Mr. Jimison was the Head of the Energy Section of the Library of Congress. One of the people who reported to him was Larry Kumins, an energy economist who first told Mr. Jimison about a newly formed local group: The Association of Energy Economists. Mr. Jimison thought that it was a great initiative, and after he heard about the first meetings of the Association, he thought that he also would like to join if they would allow non-economists. He started to participate in the meetings of the Washington group, one of the original groups of the Association – the other one was formed in London.

In 1981 Mr. Jimison moved from working for the Congress to working at the International Energy Agency in Paris. When he moved back to the US in 1985, one of the first things he did was to rejoin the Association`s meetings, because by that time it was – as it is today—a great way to renew and make contacts in the energy analysis community in Washington, D.C..

In 1989 he got a telephone call from the manager of the Association. The Association was in financial troubles and on the edge of bankruptcy. They needed legal advice which they could not afford at that time, and he was the only member who was also a practicing attorney. Mr. Jimison agreed to help the Association as much as he could on a pro bono basis, and he has been IAEE's lawyer on that basis ever since. The Association managed to avoid bankruptcy and changed management: AMS (David Williams' firm) started to manage the Association. AMS has built since then a healthy worldwide organization that is financially stable. Not infrequently, however, the Association needs legal advice, and this is why Mr. Jimison was consistently reinvited to remain as the General Counsel.

Working within the Association was very helpful for Mr. Jimison's work. As was mentioned in this conference's opening address, policy has a fundamental foundation on economics. If you do not understand how energy economics works, you cannot make a good energy policy. It was always very helpful to Mr. Jimison to be able to talk about the economic basis for policy with policy makers. In his work within Congress, he was able to feel comfortable that the policies they were recommending were at least evaluated on an economic basis, as exemplified in the papers and conferences of the Association.

When asked about a specific legal issue which required Mr. Jimison to be involved, he mentioned the organization of an IAEE International Conference in Tehran, Iran in 2004. When the planning started during the Clinton administration, there was progress in reconciling the USA with Iran, and organizing this conference seemed doable. However, it became more challenging during Bush administration. Non-profit American corporations such as IAEE were barred from supporting or organizing conferences in Iran, an alleged member of the so-called "Axis of Evil." IAEE leaders and staff would be considered as breaking the law to be associated with organizing the conference in Tehran. Mr. Jimison negotiated with the State Department, pointing out IAEE's truly international nature. But he lost. If you look at IAEE's website and the historical track record of international conferences, the international conference for 2004 is missing. It could not be called an IAEE conference and the Association's officers could not be involved in its planning. The conference was still held, however, and many Americans participated in this successful conference. It is the only year without an official IAEE international conference back to 1979, ironically the first one Mr. Jimison attended himself, speaking there about the economic basis for energy policy in Congress.

Mr. Jimison is very honored to receive this award. According to him, IAEE has offered a wonderful group of people to work with over all these years. The Association has brought much more to him than he feels he has contributed to it. He is always happy to help, and he is pleased to be recognized as having helped.

Interview with Ian Parry, International Monetary Fund - Winner of the Outstanding Contributions to the Profession Award

Awarded since 1981 to an individual for outstanding contributions to the field of energy economics and its literature.

Since his graduate school days at the University of Chicago, Mr. Parry has always been concerned with the practicalities of moving energy and environmental policy forward. He spent 15 years at Resources for the Future, a research institute in Washington DC, doing applied research on the design of energy, climate, and transportation policy, emphasizing the role of tax policy to factor environmental costs into the price of energy and consumer products. Eight years ago Mr. Parry joined the Fiscal Affairs Department of the IMF where he has responsibility for providing quantitative, country-specific analysis and guidance to help countries move forward with their commitments for Paris Climate Change Agreement and the broader reform of energy pricing to fully reflect supply and environmental costs. He has had the privilige to study under, and work with, many leading energy, environmental, tax, and other economists who have informed his thinking, including Gary Becker, Larry Goulder, Arnold Harberger, Michael Keen, Alan Krupnick, Wally Oates, Billy Pizer, Paul Portney, Kenneth Small, and others.

Much of Mr. Parry's work essentially takes the body of analysis that has been developed by IAEE members on how energy systems evolve over time and react to policy changes and translates it in a streamlined way that can inform countries on, for example, carbon prices consistent with their mitigation objectives, the broader fiscal and economic impacts of pricing, and trade offs with other mitigation instruments.

"It is a huge honor to receive this very prestigious award". Mr. Parry is especially gratified that the Association is rewarding the type of applied policy analysis that can be difficult to publish in leading academic journals.

Ian Parry has frequently attended IAEE conferences during his career and he believes the field of energy economics has developed in a very valuable and useful way. He believes we now have a reasonable quantitative sense of policy options available at the individual country level for implementing their climate strategies, how carbon pricing needs to be scaled up internationally to meet climate stabilization goals, and how fiscal policies can help countries address the domestic environmental impacts of energy use, like

health risks from local air pollution exposure. A lot of this knowledge is due to empirical and modelling analyses developed by economists within this Association.

Mr. Parry believes the key challenge now is how to address the political economy obstacles that have held up policy reform. Policymakers will need to be nimble in crafting effective strategies that are also acceptable, perhaps through accompanying fiscal measures to assist vulnerable groups and using revenues from price reform in a visible, equitable, and productive way. For some countries, approaches that can mimic many of the responses to price reform but without a substantial increase in energy prices may be the more practical strategy. At the international level, Mr. Parry recommends policymakers consider the possibility of a voluntary carbon price floor arrangement among large emitting countries to complement and reinforce the Paris process. He believes members of this association can provide a lot of creative thinking and valuable analysis along these lines to help move policy forward at a critical time.

Suncor Technical Visit

BY THERESIA BETTY SUMARNO, PHD CANDIDATE, UNIVERSITY OF DUNDEE

Leaded by Sylvain Audette, we headed off to the Suncor, Montreal Refinery from Delta Marriot Hotel in Montreal on Wednesday morning, the 27th May 2019. Upon to our arrival, we were greeted by Mr Dean Dussault the Senior Advisor, Communications.

Prior to the plant visit, we were gathered for an introduction of the Suncor Refinery.

Ms. Caroline Montplaisir, the Vice President of the Montreal Refinery, was giving a brief overview and followed by Ms. Sophie Labelle, the Director

Interview with Elbert Dijkgraaf and Emiel Maasland, Erasmus University Rotterdam, The Energy Journal's Campbell Watkins 2018 Best Paper Award Winners

Prize awarded since 1989 for the paper designated as the most outstanding of those published in The Energy Journal during the year.

Award Winning Paper: On the Effectiveness of Feed-in Tariffs in the Development of Solar Photovoltaics. Elbert Dijkgraaf, Erasmus University Rotterdam, Tom P. van Dorp, Solarplaza International BV and Emiel Maasland, Erasmus University Rotterdam

Elbert Dijkgraaf is professor at the Erasmus School of Economics where he holds the chair "Empirical economics of the public sector". He is also fellow of the Tinbergen Institute. Emiel Maasland is affiliated researcher at the Department of Applied Economics of the Erasmus School of Economics and is the founder and managing director of Auctiometrix, an incubatee specialized in auctions. The award-winning article published in The Energy Journal is an adaptation of a master's thesis by one of Prof. Dijkgraaf's students (Tom van Dorp). Dr. Maasland was part of the thesis` evaluation committee.

The paper addresses the question whether or not feed-in tariffs are effective in encouraging the development of solar power. The main finding of the paper is that feed-in tariffs are effective provided that they are well designed. Not only the height of the tariff is important, but also the duration of the contract and the absence/presence of a cap have an impact. Policy consistency is also very important, especially when the tariff is low. "Our study shows that the literature underestimates the potential impact of feed-in tariffs, as the effect of a well-designed feed-in tariff is much larger than the average effect of the currently applied feed-in tariffs. The total effect of a feed-in tariff can be seven times as large if it is well designed."

The authors started this research because the majority of the existing literature is limited to a descriptive approach to analyzing the effectiveness of feed-in tariffs on the development of solar photovoltaics. The few empirical papers that did estimate the effectiveness of feed-in tariffs did not take design features of feed-in tariffs and policy consistency explicitly into account. In contrast to the award-winning article, these empirical papers were therefore not able to determine what drives the effectiveness of the feed-in tariffs. The award-winning article gives policy makers – via the estimated effects of the different design features – tools to optimize the feed-in tariffs.

In view of the high quality of the papers being published in The Energy Journal, it is a great honor for the authors to receive this award. Receiving this prize encourages the authors to do more energy related studies. The authors are inspired by the many policy discussions during this IAEE conference. Moreover, the diversity of the delegates` backgrounds is valuable for learning about different perspectives and broadening the knowledge of challenges and issues within the field of energy economics.

Engineering, of the Montreal Refinery.

Ms. Labelle explained about the Suncor Company, Oil Sands recovery, the process of the refinery in the Suncor Company and she also mentioned the final products. At the end of the presentation, the Q&A session was opened for all the participants, and then we have a group picture taken.

The next activity is the plant visit, and we were guided by the Senior Engineer, Production and Energy the of Montreal Refinery, Ms. Gisele Tong. We entered the refinery plants by bus, and Ms. Gisele was giving us explanation for each of the plant. We first started with the water treatment plant, then moving into the crude oil distillation unit. She explained the process of the refinery process, the catalytic and cracking process. The next plant was the butane refinery plant which has very interesting shape, like a massive ball. The last one is the storage units. Many questions were raised during the plant visit.

After spending 2.5 hours in Suncor and finishing all the activities, we went back to Delta Hotel, and we all were very pleased for participating in this field visit. Thank you IAEE!

Interview with Yukari Yamashita, IAEE President - elect

In 1985, Yukari Yamashita joined the Institute of Energy Economics (Japan). She was then asked by Professor Kenichi Matsui to be part of the hosting team of the first IAEE International conference in Japan. Organizing a conference in 1985, was very different compared to today; everything had to be typed manually and computers were not used as much. The conference was very successful, and in addition to many renowned speakers, the Ministers of Energy from Indonesia and Japan each gave speeches. This is how Ms. Yamashita became an IAEE member.

The second time Ms.Yamashita worked with IAEE was when she was asked to attend the IAEE`s council meeting in Stavanger, Norway on behalf of Mr.Matsui.

The third time was when Ms.Yamashita stepped-in for Mr.Matsui to make a keynote address at the IAEE International Conference in Perth, Australia. Afterward, Ms. Yamashita became a board member of the Association.

After that first experience of attending the Association's board meeting in Stavanger, Ms. Yamashita tried to contribute as much as possible by expressing her opinions and sharing her knowledge. Ms.Yamashita says that, it was very interesting to be part of the discussion regarding the Association's regional expansion. Asia is still underrepresented within the Association, even though it is a part of the world where energy consumption is growing. Ms.Yamashita says that having representatives from Asia within the Association is important to make the region visible. She further adds that female representation within the Council is crucial, and she is proud to represent women in this way.

As President-elect for the Association since early 2019, Ms. Yamashita says that she is in a process of learning. Her main priority is to ensure that the IAEE's strategy is properly implemented. Given the complexity of the President's role, it has been recently discussed that the role of the IAEE's immediate Past-President should be re-defined to provide the experience and the institutional memory which are valuable for the incoming President. From the initiative taken by the current President, Mr. Bonnery, as well as Ms. Yamashita, the governance structure of the Association will change in 2020. The aim of this change is to make the management more robust and to contribute towards the Association's future expansion.

For the next few years, the Energy Transition will be the main focus for IAEE's meetings. Ms. Yamashita argues that although it is called "Energy Transition", this global challenge is actually driven by the concern for climate challenges. The existing energy system is not changing quickly enough in order to meet this challenge. We have a tendency to forget the long-term objective, which is not only to meet the climate challenge, but also to enable sustainable development while securing affordable energy to all. The SDGs are important. The Association's expertise, as well as the network of Energy economists, have a very important role to play here; this is the Association`s raison d`être. Hence, Ms. Yamashita would like to see not only the current members, but also the future members and young generation, engaging in this debate.

Attendee Comments

Johannes Mauritzen,

Associate Professor, BI Norwegian Business School

"The variety of disciplines and perspectives at the IAEE conferences is pretty unique. I like hearing from people from not only economics, but also engineering, public policy, environmental science and many more."

CONFERENCE OVERVIEW

The 43rd IAEE International Conference takes place in Paris, France, at the Palais des Congrès 21 – 24 June 2020, with the main theme **« Energy and Climate, Working hand in hand »**.

An ideal climate and energy policy regime should simultaneously address possibly conflicting objectives: ensuring energy security, promoting universal access to affordable energy services, and fostering greener and sustainable energy systems.

These policies notoriously have heterogeneous impacts on states, consumers, factor prices, energy technologies and existing assets like fossil reserves and carbon-intensive capital stock. Building credible and effective policies is a difficult task and needs to take into account geopolitical, economic and environmental realities to make them acceptable.

Against this background, the pressing quest for credible and sustainable solutions imposes to rapidly develop deep and broad analyses of policy instruments and institutions. It requires a broad mobilization of the concepts and notions used in economics, natural sciences, humanities or other social sciences to inform the numerous public policy debates affecting international energy trade, environmental regulation, markets vs. government intervention, energy infrastructure and technology choices.

The conference provides a unique platform for academics, policy-makers and business leaders from around the world from all over the world to present and discuss the latest economic research on pressing energy issues in an open and nonpartisan setting. The conference also sends a particular welcome to the many environmental and natural resource economists working on these topics.

Paris has a distinctive identity that makes it an ideal location to foster these discussions. The city has been an academic hot spot for centuries and the 2015 United Nations Climate Change Conference made it an epicenter of climate policy. As a vibrant business capital, Paris is also home to a diverse energy sector and a unique collection of leading international organizations and think tanks.

For further information please contact: iaee2020@oyco.eu


Palais des congrès Paris

CONFERENCE VENUE

The conference will be held at the Palais des Congrès, the leading venue for international congresses in Paris. On the first conference day, our delegates are welcome to join the welcome reception at the Conference hotel: Le Meridien. The Hotel interior is inspired by mid-century modern design, with clean lines accentuated by sculptural forms and rich fabrics, that are unmistakably reflective of Paris.
Conference`s Gala dinner will be hosted by the City of Paris at the Hôtel de Ville. This unique venue will open its doors only for our delegates to guarantee an exclusive experience of the French hospitality and cuisine.

Paris is an international city with many centuries of history, offering an excellent starting point for travelling to France and exploring the beauty of the most fascinating city in Europe.

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43RD IAEE PARIS 2020 INTERNATIONAL CONFERENCE

21-24 June 2020 | PARIS | FRANCE

Energy and Climate, Working Hand in Hand

CALL FOR PAPERS

WHO'S INTERESTED?

The conference is intended for:

- Academics and scholars working in the fields of energy, natural resources or environmental economics,
- Policy makers and officials in governments, international institutions and regulatory agencies,
- Energy analysts working for local authorities, development agencies, consumer bodies, NGOs,
- Business leaders and practitioners.

From a methodological perspective, the conference welcomes contributions based on: analytical models, econometrics, experiments, surveys, rigorous institutional analyses and case studies, simulation models, equilibrium models, optimization models. Interdisciplinary works with all areas of the natural, social or engineering sciences are also welcome.

TOPICS TO BE ADDRESSED

The general topics below are indicative of the subject matters to be considered:

- Blockchain experiments and regulation
- Disruptive business models in energy sector
- Economics oil and gas markets, Developments in LNG markets
- Electricity demand response, Self-consumption, Electricity tariffs and smart meters, Nudges in electricity consumption
- Emissions Trading Schemes, Energy efficiency
- Energy and climate change mitigation and adaptation
- Energy and emission modelling
- Green Innovation, Biofuels and Bioenergy
- Local energy communities, Electric mobility, Big data and energy
- Nuclear energy markets
- Regulation of energy network industries
- Renewable energy sources and industries
- Role of new technologies in Energy Transition
- Smart grid, Microgrids, Energy storage and electrification

CONCURRENT SESSION ABSTRACT FORMAT

We welcome contributions from researchers and industrial sector representatives. Authors wishing to make concurrent session presentations must submit an abstract that briefly describes the research or case study to be presented. We will begin to receive abstracts from June 2019.

PRESENTER ATTENDANCE AT THE CONFERENCE

At least one author of an accepted paper or poster must pay the registration fees and attend the conference to present the paper or poster. Authors will be notified by 6 March 2020 of the status of their presentation or poster.
Final date for speaker registration fee, extended abstracts and full paper submission: 17 April 2020.

Abstract submission deadline:

Friday 24 January 2020

iaee2020paris.org

STUDENT EVENTS

Students may, in addition to submitting an abstract, submit a paper for consideration in the IAEE Best Student Paper Award Competition.

We also encourage students to participate in the Student Poster Session and to submit a paper for consideration in The Special PhD Session.

Students may inquire about scholarships covering conference registration fees.

For more information, please CONTACT:
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Biomont Biomass Cogeneration Plant Tour

BY CARO DAHL, PROFESSOR, COLORADO SCHOOL OF MINES

This project started life as a quarry. When it was quarried out, the gaping hole begged to be filled. The community fervently filled the resulting landfill with their trash. Eventually NIMBY kicked in as the surrounding community did not appreciate the landfill's

fragrance.

A 25 MW steam turbine was put in to generate electricity from the biogas, mostly methane, generated by the landfill. It just goes to show that what is trash to some is energy to the more resourceful. The properties latest incarnation is a co-gen plant inaugurated by Biomont Énergie in 2017.

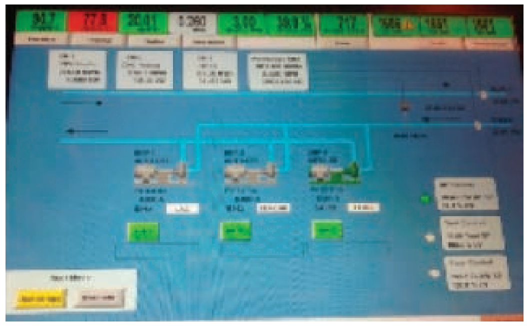
This limited partnership is between Fondaction, Eolectric (the operator), and VALECO. This small plant, the first of its kind in the province of Quebec, is run by three employees. The gas is piped out of the landfill and through units where humidity and sulfur are removed.

1.6 MW internal combustion engine

The biogas can run three 1.6 MW internal combustion engines generating enough electricity for about 1900 homes. The project keeps methane, an even more potent greenhouse gas than CO2, from escaping into the environment.

A jumble of wires snaked up, over and across, delivering power to the grid.

Status of the operating units



A blue screen in a console tells those in the know the status of the operating unit.

It annually removes greenhouse gases equivalent to the emissions of about 50,000 cars. Some donned ear protection to take a closer look at the noisy engines turning biogas into power.

The co part of the co-generation plant is the recovered heat that warms the water for some nearby heating systems.

Our thanks to Biomont for the tour of their facilities. Although tiny by utility standards, this points us to consider all local options to solve a global problem. For more on way we all can reduce emissions of carbon, see the book *Drawdown* (https://www.drawdown.org/). For a longer version of this article with more pictures see https://dahl.mines.edu/BiomontCogen.pdf .

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28790 Chagrin Boulevard, Suite 350
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