Competitive Energy Storage And The Duck Curve

Richard Schmalensee[a]

Power systems with high penetrations of solar generation need to replace solar output when it falls rapidly in the late afternoon – the duck curve problem. The traditional solution to this problem would be to build and use more gas turbines or combined cycle plants that can increase output rapidly. However, this is inconsistent with the goal of reducing carbon dioxide emissions. As the costs of storage have declined, storage has emerged as a potentially attractive, carbon-free alternative way of offsetting diurnal declines in solar generation. This paper considers whether competition can be relied upon to provide an efficient supply of storage in this context.

I consider a Boiteux-Turvey-style model of an electric power system with alternating periods of two types, labeled daytimes and night-times, corresponding roughly to the duck's back and its neck. Renewable generation has positive, stochastic output only in daytime periods. Gas generation, which, for simplicity, stands in for the whole suite of dispatchable generation technologies, is assumed to be available in both daytime and nighttime periods. Short-term storage can be installed at a constant cost per unit of capacity, and storage involves a constant fractional round-trip loss of energy. Demand in both days and nights is stochastic, constant within periods, and perfectly inelastic. Price is assumed to rise to the value of lost load if demand exceeds available supply.

Under constant returns, competitive generators' operating rules are simple: produce if and only if market price of energy is greater than or equal to marginal cost. In general, optimal charging or discharging of storage under competition depends on the current energy market price, the amount of energy in storage, and expectations regarding future energy prices. In general, it does not seem possible describe the behavior of competitive storage suppliers when storage is not fully discharged in each nighttime period without additional assumptions or resorting to numerical methods. In the context of the duck curve, however, at least in the near term, imposing the restriction that storage is fully discharged in each nighttime seems reasonable. Doing so leads to three possible regimes relating the marginal cost of gas generation to expected nighttime prices. The first-order conditions for minimizing expected total cost in each regime are exactly the break-even conditions for long-run competitive equilibrium. Thus all expected cost minima are long-run competitive equilibria.

It has not been possible to prove that the corresponding Hessian is always positive-definite, but its diagonal elements, the own second partial derivatives of the expected total cost function are always positive. Thus the long-run equilibrium value of storage capacity always minimizes expected system cost conditional on generation capacities.

As noted above, the formal analysis in this paper makes the usual assumption that the energy price rises to the value of lost load in shortage conditions. If the energy price is capped below the value of lost load, however, this analysis implies the existence of a "missing money" problem for storage, exactly like the problem that has led to the proliferation of "capacity mechanisms" to supplement energy market revenues in order to provide incentives for adequate investment in generation.

a Howard W. Johnson Professor of Management Emeritus and Professor of Economics Emeritus, Massachusetts Institute of Technology, Cambridge, MA 02139; USA. Email: rschmal@mit.edu.

The Energy Journal, Vol. 43, No. 2

North American Natural Gas Markets Under LNG Demand Growth and Infrastructure Restrictions

Baturay Çalcı,[a] Benjamin D. Leibowicz,[b] and Jonathan F. Bard[a]

In this paper, we investigate how North American natural gas markets and infrastructure evolve under various scenarios distinguished by different levels of liquefied natural gas (LNG) demand and restrictions on where new LNG export facilities can be built. We are motivated by the strong LNG demand growth, especially in Asia, which could increasingly motivate gas infrastructure development in North America. However, opposition to new gas infrastructure is formidable in some U.S. states and Canadian provinces that are well positioned to supply LNG to the Asian market. In order to analyze the effects of these two conflicting phenomena, we build a mixed complementarity model with endogenous capacity investments. The model is a collection of optimization problems of six strategic player types: suppliers, traders, storage operators, liquefiers (LNG exporters), the pipeline network operator, and the tanker network operator. Market clearing conditions among these players and demand markets are used to determine regional market prices. Our model includes six regions for the U.S., two regions for Canada, and one region for Mexico, as well as two LNG demand regions for the Atlantic and Pacific LNG markets. The model is parameterized using publicly available data sources, and five main scenarios are run through the year 2050 based on LNG demand, North American demand, and restrictions on building new LNG infrastructure in the Western U.S. and Western Canada. Our results show that even if new export terminals cannot be constructed on the West Coast, LNG exports largely shift to other regions, most notably the Southwest region of the U.S., rather than suffer an overall decline. This suggests that the total North American LNG export volume would be robust to regional infrastructure restrictions. We also observe that increasing external demand for LNG puts upward pressure on regional prices in North America, and directs production and pipeline flows toward the regions that export LNG, as well as inducing capacity expansions in both production and pipelines to support growing LNG exports.

Modelling the Global Price of Oil: Is there any Role for the Oil Futures-spot Spread?

Daniele Valenti[c]

It is widely accepted that crude oil represents the most important and traded commodity in the world. Modelling the real price of oil and understanding the economic factors behind oil price fluctuations provide a useful content resource for institutional and private organizations. In this study, we illustrate the main benefits of accounting for the oil futures-spot spread (henceforth, spread) in a Structural Vector Autoregressive (SVAR) model of the global market for crude oil. The spread is defined as the ratio of oil futures prices over the relative oil spot prices minus one and the free-risk interest rate, after accounting for the time to maturity of the futures contract. According to the theory of competitive storage, the spread can be interpreted as a proxy for the net-convenience yield of oil stocks, although expressed with an opposite sign. This measure is derived by crude oil

a Graduate Program in Operations Research and Industrial Engineering, The University of Texas at Austin.

b Corresponding author. Graduate Program in Operations Research and Industrial Engineering, The University of Texas at Austin, ETC 5.128D, 204 E. Dean Keeton St., C2200, Austin, TX 78712, United States. E-mail: bleibowicz@utexas.edu

c University of Milan - Department of Environmental Science and Policy (DESP), Milan, Italy. E-mail: daniele.valenti@unimi.it.

Brent futures prices with maturity 3-months, since about two-thirds of oil purchases at world level use Brent as a reference price.

Most of the oil market VAR models use an inventory-based detection strategy to identify the speculative demand for crude oil. In contrast, our study provides three main reasons to consider the spread as a reliable measure of oil market expectations. First, the spread accounts for the price discovery role in the futures market. Second, the spread-based model alongside a proper set of identifying assumptions allows to examine the role of oil price speculation by accounting for possible frictions, which may limit arbitrage activity in the global market for crude oil. Finally, the proxies global above-ground crude oil inventories are affected by measurement errors.

Our model provides empirical evidence that, the spread responds to oil price shocks differently, depending on the economic motivations behind each shock. On average, oil supply disruptions and positive shocks to global business cycle cause a large and persistent drop in the spread, consistent with the fact that, inventories are used for consumption and production smoothing, respectively. Conversely, shocks to the demand for storage driven by fears of production shortage cause a small decline in the spread. Finally, the dynamic response functions show a positive relationship between the spread and the real price of oil, triggered by speculative shocks to financial markets. This last type of shock induces an increase in the demand for below-ground crude oil inventories because the future path of the spot price of oil is expected to rise.

Finally, our study provides a clear picture of the historical dynamic of the real price of oil and the spread. To illustrate this point, we focus on four exogenous events in global crude oil markets: the 1990-1991 Persian Gulf War, the 2003–2008 oil price surge, the 2008–2009 global financial crisis and the 2014–2016 oil price slump.

The Heterogeneous Impact of Coal Prices on the Location of Cleaner and Dirtier Steel Plants

Francois Cohen[a] and Giulia Valacchi[b]

The Paris Agreement (2015) has set the ambitious objective of limiting global warming below 2°C. Yet, the Nationally Determined Contributions (NDCs) agreed on by the Parties to the Agreement are insufficient to reach the below 2°C target. Delivering the promise of the Paris Agreement comes at a cost for national industries, especially those reliant on fossil fuels, such as steelmaking. They are afraid to lose competitiveness if ambitious environmental policies are implemented unilaterally.

We estimate the effect of coal prices on steel plant location. Coal is by far the main input responsible for CO_2 emissions in steelmaking. We furthermore look at production preferences for Basic Oxygen Furnaces (BOF), a polluting technology, and Electric Arc Furnaces (EAF), a greener one. Looking jointly at the effect of energy price shocks on plant location and production preferences constitutes the main contribution of this paper. The two are likely to interact since manufacturers may not need to relocate if they can adopt low-pollution technologies instead.

We find that an increase in coal prices at national level has a negative effect on the size of steel manufacturing in a country. In our preferred specification, a 1% increase in coal prices reduces

a Corresponding author. Department of Economics, Chair of Energy Sustainability and Barcelona Institute of Economics, University of Barcelona, Barcelona, carrer de John Maynard Keynes, 1, 11, 08034 Barcelona, Spain. Email: francois.cohen@ub.edu

b World Intellectual Property Organization, Geneva, Switzerland.

BOF production capacity by around 0.37%, while it has no statistically significant effect on EAF capacity.

We simulate the implementation of a stringent European carbon market with no border adjustment and find a non-negligible shift in steel production outside Europe, partially offset by a shift in the technologies employed to produce steel. There may be limits to the diffusion of EAF, even under high coal prices, because this cleaner technology is a recycling technology that requires scrap. If applied worldwide, the same policy would lead to a relative increase in EAF production capacity, but also affect production in Asia, which relies on BOF and currently benefits from lower coal prices than those expected to emerge in the future.

All in all, these findings suggest that enhancing international coordination for the implementation of Nationally Determined Contributions (NDCs) of the Paris Agreement, in accordance with the principle of differentiated responsibilities, will be essential to increase the ambition of the NDCs.

Market Makers and Liquidity Premium in Electricity Futures Markets

Juan Ignacio Peña[a] *and Rosa Rodríguez*[b]

Electricity futures trading offers benefits to electricity producers and consumers, such as price discovery, a hedge against spot price market risk, and market power mitigation. But these benefits come at a cost when the futures price diverges significantly from expected spot prices, giving rise to a forward premium, defined as the difference between futures prices and expected spot prices. If the futures price is higher (lower) than expected spot prices during the delivery period, this cost is borne by consumers (producers). The forward premium has been studied by comparing futures prices against expected spot prices. If we use realized (ex-post) spot prices, futures prices contain forecast errors that may induce bias in the estimated forward premium. If we use the estimated (model-based, ex-ante) spot prices, the forward premium becomes dependent on the spot price model used. There are many models of the spot price, and none enjoys general acceptance. This paper studies the forward premium as a liquidity premium in electricity futures markets as determined by producers and retailers' demand for immediacy. Demand for immediacy by a buyer (seller) means the willingness to buy (sell) at the current market price rather than wait until a better price appears. An imbalance between the supply and demand of futures contracts creates a need for immediacy. Market makers satisfy this demand by offsetting the imbalance at the current market price and require a liquidity premium until the imbalance disappears. The liquidity premium is negative (positive) when market makers sell (buy) futures contracts. The empirical application to the French, German, Spanish, and Nordic futures electricity markets in 2008-2017, finds several periods with a negative liquidity premium in the first three markets, suggesting that retailers wanted to offload a higher amount of price risk than the producers. The premium decreases when market competition, as measured by the number of market makers, increases.

a Corresponding author. Universidad Carlos III de Madrid, Department of Business Administration, c/ Madrid 126, 28903 Getafe (Madrid, Spain). E-mail: ypenya@eco.uc3m.es.

b Universidad Carlos III de Madrid, Department of Business Administration, c/ Madrid 126, 28903 Getafe (Madrid, Spain). E-mail: rosa.rodriguez@uc3m.es.

Do We Need to Implement Multi-Interval Real-Time Markets?

Darryl R. Biggar[a] and Mohammad Reza Hesamzadeh[b]

With increasing penetration of intermittent generation in wholesale electric power markets, there is growing concern that, due to large swings in the supply/demand balance, ramp rate constraints on generation resources may bind from time to time. When ramp rate constraints are anticipated to bind in future dispatch intervals it may be efficient, or even essential, to 'pre-position' some resources in advance, so as to reduce the cost of dispatch during the period when ramp rate constraints are binding.

But how to achieve such pre-positioning? Several wholesale power markets have extended the real-time dispatch process to optimize over several dispatch intervals at once, into the near future. This is known as 'look-ahead dispatch' or a 'multi-interval real-time market'. The idea is to anticipate future binding ramp rate constraints and allow those constraints to be correctly and efficiently incorporated into current and forecast prices and dispatch.

But there is a problem. Several papers have pointed out that the resulting prices may be *time inconsistent*: This can be explained as follows: At the outset, the look-ahead dispatch process forecasts a sequence of efficient prices and dispatch. Faced with these prices, it can be shown that the generation resources in the market have an incentive to voluntarily comply with the dispatch instructions, including any prepositioning where it is efficient to do so. But each dispatch interval, only the first price in the sequence (known as the spot price) is used for settlement purposes. The next dispatch interval the look-ahead dispatch process is run again. Importantly, even in the case of perfect foresight (where the subsequent supply and demand conditions are exactly as originally forecast) the resulting sequence of spot prices may not be the same as the prices forecast at the outset. Faced with this out-turn sequence of prices, a generating resource may not have an incentive to comply with the dispatch instructions which were determined to be efficient at the outset. Even if pre-positioning is efficient the generating resource may have no incentive to do so.

To address this problem a couple of papers have proposed extensions or augmentations to the dispatch process to ensure the time-consistency of the resulting prices and dispatch. But the proposed extensions only work in the special case of perfect foresight. The proposed solutions effectively tie the dispatch and pricing outcomes to outcomes that were forecast at an earlier time, potentially for quite different forecast demand, supply or network conditions. In the real world, new information on supply, demand, and network conditions arrives all the time. The power system should be able to adjust efficiently to this new information as it comes along.

This paper sheds new light on the look-ahead dispatch task and the time-inconsistency problem. We point out that the time-inconsistency problem is not inherent in look-ahead dispatch, but only arises in a context where both the cost function of generators and the utility function of loads is linear. In this case there can arise an ambiguity in the definition of the wholesale price (i.e., the marginal value of the energy balance constraint) in each dispatch interval. Bellman's Principle shows that dispatch and prices which are optimal at an earlier time remain optimal (under perfect foresight) at a later time. But it turns out that the size of the set of efficient prices may increase over time. As a consequence the dispatch process may not happen to choose a price at a later time which is within the forecast set of optimal prices for that interval at an earlier time. We consider the case of linear cost and utility functions to be a special case. If either the supply curve of each generator or

a Australian Competition and Consumer Commission, Australia,

b Corresponding author: KTH Royal Institute of Technology, Sweden, E-mail: mrhesamzadeh@ee.kth.se

the demand curve of each load is continuous and upward sloping, this problem of time inconsistency does not arise.

Second, we highlight the problem of efficient response to new information. The standard formulation of look-ahead dispatch and the extensions to solve the time-inconsistency problem discussed above, assume only a single state of the world in each dispatch interval in future. In other words, these formulations assume that no new information about demand, supply, or network conditions arrives over time. This is not realistic. In all real world power systems demand, supply, and network conditions change all the time. How can such new information be accommodated?

New information can be efficiently handled in a one-off or ex ante dispatch if the dispatch itself is made contingent on that new information as it arrives in the future. This is known as state-contingent dispatch. In theory, the extensions discussed above to resolve the time-inconsistency problem (and the look-ahead dispatch itself) could be made contingent on new information as it arrives over time by applying them in a framework of state-contingent dispatch. In practice, the very large number of potential contingencies in a real-world power system makes this a practical impossibility.

But how then are we to achieve dispatch in the face of binding future ramp rate constraints? Fortunately it turns out that we do not need to implement look-ahead dispatch or multi-interval real-time markets to achieve efficient dispatch in the face of binding ramp rate constraints. We show that provided certain conditions hold, the one-shot dispatch is sufficient to achieve overall efficient dispatch outcomes. The reason is straightforward: Intertemporal constraints are private constraints for each generation resource individually. Provided that each resource forecasts the correct (state contingent) prices, each resource individually has an incentive to make the efficient dispatch and pre-positioning decisions. Neither look ahead dispatch nor other, more significant interventions (such as ex ante procurement of ramping capability or extended operating reserve) are necessary to achieve efficient outcomes.

In summary, look-ahead dispatch at best plays a role in improving forecasts of near-term prices. However, this role could be improved and made more valuable for market participants by making those price forecasts contingent on credible contingencies that may occur in the near future. Multi-interval real-time markets are not an essential feature of an efficient wholesale power market.

Short and long-term energy cost disclosure effects on willingness-to-pay for residential energy efficiency

James Carroll,[a] Claudia Aravena,[b] Marco Boeri,[c] and Eleanor Denny[d]

Motivation

While more energy efficient products generally cost more to buy, their lower running costs can make them better investments over their lifetime. Some consumers may fail to make this trade-off by choosing products with lower upfront purchase costs but higher energy consumption. This underinvestment in energy efficiency, if prevalent, is known as the Energy Efficiency Gap. Given that energy consuming products, such as appliances, cars and properties, can have relatively long

a Department of Economics, Trinity College Dublin, Dublin 2, Ireland.
b Department of Economics, School of Social Sciences, Heriot-Watt University, Edinburgh, Scotland.
c RTI Health Solutions, Belfast, Co. Down, Northern Ireland.
d Corresponding author. Department of Economics, Trinity College Dublin, Dublin 2, Ireland. E-mail: dennye@tcd.ie.

lifetimes, the legacy of poor energy efficient investments can have considerable implications for future energy supply, emissions and the climate.

Many authors have proposed reasons for the Energy Efficiency Gap, including the possibility of 'missing' or 'incorrect' energy cost forecasts. This implies that some buyers do not consider energy costs when buying i.e. they are inattentive to energy efficiency, and for those who are attentive, it is possible that their estimates of future energy cost will be inaccurate. From a policy perspective, the key question is whether or not this omission or bias is reducing the uptake of more energy efficient technologies.

In this paper, we consider two research questions:

1. Does presenting energy consumption in monetary units increase the demand for more energy efficient technologies?
2 Would increasing the horizon of the monetary forecast increase this demand further?

While there has been some research conducted to date exploring these questions for appliances and private vehicles, to the best of our knowledge, this paper is the first to examine these issues for properties, a 'product' with relatively high energy consumption.

The Research Conducted

We test the two questions above using a discrete choice experiment for a sample of over 350 renters in Dublin, Ireland. A discrete choice experiment presents the participant with a choice of two rental properties which differ according to a number of property characteristics, including energy efficiency. Participant choices are used to infer the value placed on each property attribute, including energy efficiency.

In order to test the questions above, we randomly divided our sample into three experimental groups. The control group received energy efficiency information as per the current labelling policy in Ireland (the *Building Energy Rating* (BER)), which displays a property's energy efficiency information through a non-monetary indicator (kWh/m^2/year displayed on a colour-coded efficiency grading system). In treatment group one, we converted this information into a "typical two-month energy bill" and explored the change in renter's willingness-to-pay (WTP) for energy efficiency (Hypothesis **H1**). To explore whether the temporal framing of energy cost information affects valuation (Hypothesis **H2**), we created a "yearly energy cost" label for treatment group two.

Main Conclusions

We find that long-term energy cost forecasts (in our case, annual) increase the WTP for energy efficiency whereas the short-term forecast (2 months) has no effect. Our findings therefore provide additional evidence that buyers are, to some degree, missing the long-term costs implications of their energy-consuming investments, and that such information is valued by consumers and nudges more energy efficient decisions.

Policy implications

Long-run energy cost labelling appears to be a straightforward amendment to current energy labelling policy, which are generally based on kWh or carbon estimates. However, we note that such a change in metric represents a major ideological shift in labelling in regions like the EU: prior labelling often highlights the carbon-reducing and therefore public benefits of energy efficiency while energy cost labelling shifts the focus more towards the private benefits. Public benefits may become more persuasive in the coming years as the effects of climate change become more visible to technology adopters.

Abatement Technologies and their Social Costs in a Hybrid General Equilibrium Framework

Michael Miess,[a] Stefan Schmelzer,[b] Milan Ščasný,[c] and Vědunka Kopečná[d]

We present a novel methodology to directly integrate heterogeneous micro-founded preferences into a computable general equilibrium (CGE) model with technological detail to quantify the social costs of an endogenous, demand-driven abatement technology (electric vehicles) in a general equilibrium framework. With this methodology, we not only present a novel way to hard-link microeconomic preference structures to a CGE model with technology-sharp resolution for specific sectors (passenger vehicles, electricity), but we also demonstrate an innovative method to model endogenous, demand-driven technological change.

To this end, we develop a hybrid model that directly integrates consumers' decisions on conventional and emission-reducing technologies derived from a discrete choice (DC) model into a fully dynamic CGE model. The abatement technologies focused on in this study represent four individual transport technologies, namely conventional vehicles (CV) and three cleaner alternatives such as hybrid (HEV), plug-in hybrid (PHEV), and battery electric (BEV) vehicles.[e] Demand for vehicles determines the vehicle fleet through an embedded stock-flow accounting model, affecting the use of fuel and electricity, and vehicle production sectors in the CGE model. Endogenously determined demand for electricity is satisfied by production optimised in a bottom-up electricity model to supply it by a least-cost combination of fuels and power technologies. Emissions stemming from vehicle use, electricity generation, and economic production provide an input to quantify the external environmental effects associated with the technological change.

We apply this methodology to Austria as a blueprint for further use, considering current policies to support the uptake of alternative technologies. We assess the impacts of three policy scenarios on the economy, electricity production, air quality pollutants and GHG emissions, and environmental benefits associated with the emission reductions. *MODEST* assumes modest investments in the expansion of EV charging infrastructure, and a preference shift of households to EVs due to increased environmental awareness and increasing traction of EVs as a viable alternative to conventionally-fueled vehicles. *EM+* then assumes a more rapid expansion of EV charging stations and hence more investments, as well as an increase in the mineral oil tax and vehicle registration tax (a feebate system) to foster a large-scale introduction of electromobility in individual road transport. *TARGET95* is a much more ambitious policy defined by the target that almost all (95%) newly-registered vehicles in Austria will be EVs by 2030 through increasing the mineral oil tax and registration

a Corresponding author. Institute for Advanced Studies, Vienna; Institute for Ecological Economics, Vienna University of Economics and Business; International Institute for Applied Systems Analysis. Email: miess@ihs.ac.at; mmiess@wu.ac.at

b Institute for Advanced Studies; Institute for Ecological Economics, Vienna University of Economics and Business

c Corresponding author. Charles University, Institute of Economic Studies, Faculty of Social Sciences; Charles University, Environment Center; Email: milan.scasny@czp.cuni.cz

d Charles University, Institute of Economic Studies, Faculty of Social Sciences.

e Hereinafter, electric vehicles (EVs) comprise both PHEVs and BEVs.

vehicle tax, as well as introducing stricter emission standards (as reflected in a higher purchase price of emission-intensive cars). We also explore how the economic costs to reach the 95% target in the new registrations will differ if one of these measures is implemented alone compared to a policy that introduces all of these measures jointly.

We find that, as a consequence of these policies, new registrations of EVs rapidly increase particularly at the end of the modelling period, reaching 44% in MODEST and 68% in EM+ in 2030. Hence, the share of 28% of EVs in the vehicle stock in EM+ is almost doubled in comparison to MODEST, and can be expected to be further increasing and replacing CVs beyond the model horizon. However, the relatively swift uptake of EVs in Austria in both scenarios is also supported by measures to foster electromobility that are already in place.

In terms of the macroeconomic effects, investments in charging infrastructure enhance economic growth. We show that efforts to decarbonise the transport sector can also positively contribute to growth. However, the tax-related incentives (EM+) would have a negative impact on GDP. We highlight, however, that this effect is relatively small in a range of –0.12 to –0.32% compared to the business-as-usual scenario. Still, the shift from CVs towards EVs is a relatively expensive carbon abatement measure – over the whole analysed period GDP loss is €490 per tCO_2eq: abated in EM+, and €447 in TARGET95, respectively, and these costs are declining over time, reaching €294 and €242 per tonne after 2020.

Welfare is reduced as well, but the effects are rather small and partly balanced by avoided negative environmental externalities mainly adversely affecting human health. While these incentive measures might have slightly negative effects on GDP growth, they lead to higher net government revenues. We also find that the vehicle registration tax is a more efficient measure to reach a 95% EV target in new registrations than the mineral oil tax. In particular, a balanced mix of policy instruments implies costs in terms of GDP of about 0.29% in 2030, while reaching this target only by increasing the mineral oil tax implies costs of 0.4% GDP in 2030. Increasing the vehicle registration tax alone to reach such a target is even less costly in terms of GDP than the balanced scenario with GDP costs of about 0.27% in 2030.

Part of the criticism of electric vehicles derives from the fact that air quality improvements achieved along the roads can be outweighed by the costs of increased environmental damage associated with increased production of electricity to charge vehicle batteries. We show that this criticism can be averted, at least in the case of Austria. We find that a considerably large shift towards EVs in Austria may indeed lead to an increase in emissions and hence environmental damage. However, we also find that these increases are always counter-balanced by emission reductions, environmental benefits attributed to a reduction in fuel use, and changes in the economic structure. We conclude that the economic impacts are very small and the total environmental benefits are positive. If the EM+ policy scenario is considered as a set of climate change mitigation measures, it will generate ancillary benefits due to air quality improvements at ≈50 euro per tonne of CO_2eq abated.

Overall, our modelling approach is clearly able to capture economic and environmental effects due to the shift in purchasing passenger vehicle technologies, providing a useful tool to assess the social costs in comprehensive manner.

Carbon Intensity and the Cost of Equity Capital

Arjan Trinks,[a,b] Gbenga Ibikunle[b,c] Machiel Mulder,[a] and Bert Scholtens[a,d]*

The need for governments to pursue a transition from high- to lower-carbon economic systems poses an increasingly salient financial risk. Firms may face intensified regulations that constrain and price carbon emissions. At the same time, competitors could develop lower-carbon technologies and serve the growing demand of consumers and investors for more sustainable products. Hence, the cash flows of high-carbon production activities are at risk.

This paper investigates to what extent equity market investors demand a premium to compensate for such risks and thus might raise firms' cost of equity capital (CoE). We find that firms' carbon intensity (carbon emissions per unit of output) has a distinct and robust impact on CoE: On average, a standard deviation higher (sector-adjusted) carbon intensity is associated with a CoE premium of 6 (9) basis points or 1.7% (2.6%). These results are based on a combination of portfolio-level analyses and panel regression techniques, using two comprehensive international panel data sources over the years 2008–2016.

The CoE premium is primarily explained by systematic risk factors: high-emitting assets are significantly more sensitive to economy-wide fluctuations than low-emitting ones. Carbon intensity has a stronger CoE impact in contexts in which carbon risk poses a more salient issue, such as in high-emitting sectors, EU countries, and firms subject to carbon pricing regulation.

Our findings have several implications for policymakers and practitioners. Firstly, financial market investments are considered crucial to facilitate and stimulate low-carbon activity (IPCC, 2018; UNFCCC, 2015). We establish that the risk mitigation effect provides an important, but relatively weak, market mechanism that will stimulate investment in low-carbon activities. Policymakers are informed, however, that additional regulations will be needed to foster low-carbon investment. Policies also are needed to improve disclosure and validation of firms' climate-related impacts and strategies, as the risk mitigation effect largely hinges on reliable data. Secondly, our analysis could guide investors' security selection, sector allocation, and portfolio decarbonization strategies (PDC, 2017; TCFD, 2017). Finally, firm managers are informed about the relevance of low-carbon production for the CoE, which is a key driver of business and project decisions.

Electrification and Socio-economic Empowerment of Women

Ashish Sedai,[e] Rabindra Nepal,[f] and Tooraj Jamasb[g]

After three decades of energy market deregulation, Indian electricity sector still reels under the pressure of the inability to match the demand for electricity at the household level. Post the Rajiv Gandhi Grameen Vidyutikaran Yojana, 2005, there have been significant improvements in electricity connections provided to households. However, the performance in improving the quality of

a Department of Economics, Econometrics & Finance, University of Groningen, PO Box 800, 9700 AV Groningen, The Netherlands.

b University of Edinburgh Business School, 29 Buccleuch Place, Edinburgh EH8 9JS, Scotland, UK.

c European Capital Markets Cooperative Research Centre, Via Luigi Polacchi, 11, c/o ITAB, Chieti 66100, Italy.

d School of Management, University of St. Andrews, The Gateway, North Haugh, St. Andrews KY16 9RJ, Scotland, UK.

* Corresponding author. E-mail address: arjantrinks@gmail.com (Arjan Trinks).

e Department of Economics, Colorado State University, Email: ashish.sedai@colostate.edu

f Department of Accounting, Economics and Finance, University of Wollongong, Email: rnepal@uow.edu.au

g Department of Economics, Copenhagen Business School, Email: tj.eco@cbs.dk

electricity provided to households has been dismal; on average, six relatively poorer and populous states in India still have less than 60% of electricity hours in day. This inability to meet the demand due to poor infrastructure, transmission and grid capacity limits the opportunities for women's participation in the labor market, efficiency in home production activities, and consequently hinders their empowerment.

We gain insights into effects of the quality of electricity on women's empowerment by using a unique nationally representative gender dis-aggregated survey in India (India Human Development Survey, 2012). Under a comprehensive framework to measure empowerment and robust estimation techniques capturing the endogeneity in empowerment and electrification, we empirically explore the effects of additional hours of electricity in the household on women's socio-economic outcomes.

As empowerment is a multi-faceted concept, we use market and non-market based indicators at the individual and household level reflecting women's access to economic and social capital, agency to make and exercise their decision, and ability to achieve economic and social independence. A Nash bargaining model is used to derive testable hypothesis. The model predicts that the underlying cause of empowerment is the exhibition of strong preference for higher hours of electricity by the woman in the household, in the absence of which the household might not be willing to acquire better quality of electrification.

The issue of endogeneity at hand is: are women with strong bargaining power and economic autonomy able to acquire better electrification, or is better electrification the cause for improving their bargaining power and autonomy? In order to capture the issue of endogeneity we use an instrumental variables approach with 'average hours of electricity in the household at the district level in the state, except the district of the household'. We argue that this instrument satisfies the exclusion restriction and captures the general equilibrium effects giving us robust casual estimates that could be used to understand the magnitude of effects.

The study highlights the role of the quality of electricity in improving women's economic autonomy, decision making ability, agency, mobility, likelihood of employment, work days, work hours, fuel and water collection minutes and use of time saving energy resources at the margin of deficiency of electricity hours. The pathways to empowerment are through the labor market and respite effects of better electrification. Having electricity throughout the day allows for more efficient time allocation in household activities and labor supply, which has a positive effect on women's work days and likelihood of employment. It provides women with respite from arduous housework which can be eased if electricity is available 24*7. In addition to these, reliable electricity allows for use of more efficient household energy resources which are time efficient and healthy.

Given the multi-dimensional impacts of reliable electricity on women's autonomy, this study adds to the debate on considering 'electricity as a right'. On the one hand, the quality of electricity disproportionately improves women's lives and so it should be considered a right to achieve the sustainable development goal of gender equity, through equality, inclusion and participation in societies structured around grave inequalities and exclusions. On the other hand, the magnitude of our estimates are incentivizing for distribution companies as they reveal the potential benefits of providing service quality. These unaccounted margins could either be used for appropriate pricing, or could be leveraged for more support from the government.

Cooperate or Compete? Insights from Simulating a Global Oil Market with No Residual Supplier

Bertrand Rioux,[a] Abdullah Al Jarboua,[a] Fatih Karanfil,[a] Axel Pierru,[a] Shahd Al Rashed[a] and Colin Ward[a]*

Structural changes in the global oil market are disrupting conventional market dynamics and the roles played by competing and cooperating producers. Industry players are adjusting to the tight oil revolution and the possibility of a plateauing or peaking global oil demand. In particular, OPEC and Saudi Arabia, its top producer, are reshaping the organization's role as the primary residual supplier to the world oil market and have invited other major exporters to contribute to stabilizing prices under the Declaration of cooperation.

Given these changes, what if OPEC decided to cease organizing residual production collectively? In this paper, we develop an economic equilibrium model that uses detailed oil supply activities calibrated using Rystad Energy's Ucube upstream oil and gas database. We design scenarios to assess the medium-term consequences (i.e. up to 2030) of a shift in the structure of the world oil market. This includes competitive scenarios that assume all oil producers behave as price takers (i.e. no residual supplier). We contrast the competitive scenarios with a reference scenario in which the actions of a residual supplier result in a market outcome aligned with WEO's projections. We examine two cases within the reference scenario: in the first, OPEC members collectively operate as a residual supplier; in the second, Saudi Arabia acts as the only residual supplier, and other OPEC members join the competitive fringe. Using a demand curve calibrated to WEO's projections, we simulate competitive scenarios under different constraints capping investments, given that the amount of capital available globally for investment in the upstream oil sector can be influenced by global megatrends (such as shifts in funds allocation due to environmental concerns).

The results from our competitive market scenarios indicate that between 2020 and 2025 prices would decline on average by up to U.S. \$11/b (14 percent) relative to prices in our reference scenario. Prices subsequently recover to the reference residual supplier scenario levels. Prices under our competitive market scenarios have a high sensitivity to growth in tight oil production. Depending on upstream investment trends, we find significant variability in the mid-term price response.

When all countries behave competitively, we find that a reduction in the global investment cap results in an increase in the cash flows of low-cost producers. The cap implicitly raises the investment costs for all projects by imposing a scarcity premium on investment, but low-cost producers remain profitable. This for instance means that Saudi Arabia would benefit from a decrease in the financial resources available for the global upstream oil sector.

We also study the economics of the residual supplier and investigate whether serving as a residual supplier can increase Saudi Arabia's oil revenues relative to purely competitive market behavior (at least in the context of our reference scenario). We estimate Saudi Arabia's free cash flows, defined as net revenues less capital expenditures, under the competitive and residual supplier scenarios. We find that when acting as a residual supplier without support from OPEC, Saudi Arabia's profits are lower than in the competitive scenarios. The fundamental reason behind this finding is that Saudi Arabia's market share is relatively small, and the price elasticity of global demand is too high.

a King Abdullah Petroleum Studies and Research Center (KAPSARC).
* Corresponding author. E-mail: bertrand.rioux@kapsarc.org.