The Cost of Carbon Leakage: Britain's Carbon Price Support and Cross-border Electricity Trade

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Asymmetric carbon pricing by one country or region is likely to distort trade and give rise to carbon leakage. Regional schemes like the European Union's (EU) Emission Trading Scheme (ETS) partially mitigate this by agreeing a uniform carbon price for some industries (the covered sector responsible for about half the total EU's emissions). While this should reduce the distortions (from asymmetric carbon taxes) within the EU, it is still prone to leakage to the rest of the world. The main industries affected by carbon leakage are carbon-intensive traded goods such as steel, aluminium and cement. The electricity sector is, however, considerably more carbon intensive than these. In the EU-28 electricity accounts for just over 20% of total greenhouse gas (GHG) emissions, with very little decrease since 1990. The electricity sector is therefore of central importance when studying the impact of differential carbon prices. It has the added advantage that electricity is not widely traded outside the EU, but within the EU, Great Britain (GB) faces potentially a 13% import share. A study of differential carbon prices within EU's *Integrated Electricity Market* isolates the impact, and allows us to ignore the rest of the world, except for the impact on global emissions.

GB, The Netherlands and France have all been coupled since early 2014, while the interconnector between GB and the Single Electricity Market of the island of Ireland was only coupled in October 2018. Coupling ensures that interconnectors are either fully used or equalize prices at each end, making the impact of changes in prices on interconnector flows both transparent and easier to model. Britain uncoupled from the EU on 1 Jan 2021 as a consequence of Brexit. We therefore restrict our study to GB's trade with France and The Netherlands from early 2014 to 2020In 2011, the UK Government enacted a gradually escalating Carbon Price Floor for fossil generation fuels. This came into effect in April 2013 in the form of a carbon tax (the Carbon Price Support, CPS, an addition to the EU carbon price) on generation fuels in GB (but not Northern Ireland). From 2016 the CPS has been frozen at £18/tonne CO_2, while the EU Allowance (EUA) price has risen from a low of €6/t CO_2 in 2011 to over €55/t by mid-2021. After leaving the EU, GB set up its own Emission Trading Scheme (ETS), with prices slightly higher than in the EU ETS. Together with the CPS GB generators faced a total carbon price of €80/t CO_2 by 2021, within the range of the Paris target-consistent carbon price. We therefore take €80/t as the social cost of carbon (dioxide).

This paper takes GB as a case study and quantifies the costs and benefits of cross-border electricity trading between interconnected countries in the presence of the CPS (an asymmetric distortionary carbon tax). We restrict our study to GB's trade with France and The Netherlands from early 2014 to 2020. We defend the assumption that the ETS acts as a carbon tax, and as such leads to carbon reductions. We find that the GB carbon taxes have a large impact on global welfare through their emissions reductions, but this is partly offset by carbon leakage to other connected countries. The paper quantifies the impact of the CPS on electricity prices, interconnector flows, congestion revenue. It also estimates the deadweight loss and carbon leakage caused by the asymmetric carbon price. This has implications for the design and ideally harmonisation of the EU carbon tax to improve the efficiency of electricity trading.

a This paper substantially extends, updates and replaces the earlier EPRG WP 2005 *The Cost of Trade Distortion: Britain's Carbon Price Support and Cross-border Electricity Trade*

Results

We estimate that over 2015–2020 when the CPS stabilised at £18 (€20) /tCO_2, the CPS raised the GB day-ahead price by an average of €10.3 ±1.1 /MWh (about 24% of the GB wholesale price) allowing for replacement by cheaper imports. The CPS increased GB imports from France and The Netherlands by 14±1 TWh/yr (about 5% of the GB annual electricity demand), thereby reducing carbon tax revenue by €102±13 m/yr (about 10% of the 2017 CPS tax receipts). The commercial value of interconnectors (measured by congestion income) increased by €131±7 m/yr (by 80% relative to the zero CPS case), half of which was transferred to foreign interconnector owners. The asymmetric carbon taxes created deadweight losses of €72±16 m/yr, about 2% of the global emissions reduction benefit of the CPS at €2.9±0.1 bn/yr. Increased French exports raised French prices by 4% and Dutch prices by 3%. Finally, about 16.3±3.5% of the CO_2 emission reduction is undone by France and The Netherlands, with a total monetary loss of about €584±127 m/yr.

Despite the fact that the CPS has distorted the cross-border electricity trading, it has significantly reduced GB GHG emissions from electricity generation—the share of GB coal-fired generation fell from 35% in 2015 to less than 3% in 2019. On 21 April 2017, GB generation achieved the first ever coal-free day. When the UK introduced the CPF, the hope was that other EU countries would follow suit to correct the failures of the Emissions Trading System, at least in the electricity sector. Since then the EU carbon price has risen but the asymmetry remains. As the electricity sector in most countries is the cheapest source of reducing CO_2 emissions and as carbon taxes are an attractive way to reduce the distorting cost of raising tax revenue, the case for an EU-wide carbon price floor are clear. This case is further strengthened by the desirability of correcting trade distortions. Now that the UK has left the EU, the simplest solution for GB is to replace the ETS by a target-consistent carbon tax, which would be close to the 2021 EUA level.

Energy Efficiency Premium Issues and Revealing the Pure Label Effect

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Climate change continues to be one of the most topical concerns of political discussion and decision-making, and measures have been taken in various parts of commercial trade to reduce energy consumption and carbon emission. Through the implementation of energy performance certificates (EPCs) for buildings in 2002, and more recent endeavors such as the CONSEED and PENNY projects, funded by Horizon 2020, the EU has a continuing focus on energy consumption, efficiency and development of policies to increase environmental sustainability.

The EPC policy is aimed to provide information and awareness regarding the energy efficiency of buildings and to create economic incentives for actors to invest in environmentally friendly improvements of buildings. The capitalization of energy efficiency in transaction prices and rents has been subject to much research in recent years. However, it is challenging to assess the policy implication of EPC implementation due to several confounding factors, such as issues related to data limitation and sample time period, together with endogeneity problems originating from omitted variables that might be correlated with energy efficiency and prices.

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This paper attempts to address the issues related to the price impact of energy efficiency by applying different identification strategies using highly representative samples from the Norwegian rental market ($N = 670,000$) between 2011 and 2019 and the Norwegian sales market ($N = 750,000$) between 2010 and 2017. We find that the valuation of energy efficiency is subject to endogeneity originating from unobserved locational factors, and that dwellings with lower energy efficiency are associated with more locational bias in the rental market, while this bias is higher for the energy efficient dwellings in the sales market. Further, we find that the lower the energy efficiency, the less bias comes from unobserved quality in the sales market. Overall, improving the energy efficiency of the dwelling with one letter on the EPC rating has similar effects for both rental and sales objects, with a price impact of about 0.8-1.0%.

The signaling effect of labeling seems to have immediate, short-run, and long-run price effects and different effects are observed in different submarkets. The findings also highlight the possibility that different conclusions might be drawn due to sample selection issues related to time periods and submarkets, and that methodological and data limitations are essential factors that must be considered when assessing the effects of the EPC implementation.

Market Power and Long-term Gas Contracts: The Case of Gazprom in Central and Eastern European Gas Markets

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Long-term supply contracts (LTCs) in many sectors have been extensively studied using transaction-cost economics. LTCs can serve multiple purposes: (i) protecting buyers and sellers against opportunistic bargaining due to the presence of highly asset-specific investments, (ii) deterring regulatory and political opportunism and ensuring fixed cost recovery, and (iii) distributing risks across the parties. In the gas supply industry, these objectives have taken the form of specific clauses: (i) linking the value of gas to prices of competing fuels (e.g., oil derivative products) in immature markets where wholesale gas trading is limited; (ii) destination clauses and profit-sharing mechanisms to restrict delivery to particular supply points, and (iii) take-or-pay clauses to distribute volume and price risks amongst buyers and sellers.

Since the early 2000s, the European Commission (EC) has sought to exercise its regulatory powers to integrate the European gas market by making LTCs in both upstream and downstream gas markets more competitive and by curbing the market power exercised by dominant incumbents at the national as well as supranational level. The first EC investigation was initiated in 1998, interest accelerated after adoption of the Third Energy Package in 2007 and its implementation in all Member States (MS). The Directorate-General for Competition (DG COMP) has investigated major European national incumbents as well as LTCs with major sellers of gas to the EU for anti-competitive and market segmentation practices. Over the past two decades, this process has led to restructuring LTCs by indexation of gas to traded price indices (e.g., TTF and NBP) in contract price formation, allowing third parties access to the market and the transmission and distribution network, and removing destination restrictions.

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In 2012, the EC initiated proceedings into the Russian state-owned producer Gazprom's LTCs with eight Central and Eastern European (CEE) MS - Bulgaria, Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland and Slovakia. The EC objected to Gazprom's practice of segmenting markets along national boundaries by refusing to change delivery points, using this segmentation and its dominant position in these markets to charge high prices, and obtaining unrelated commitments from its contractual counterparties concerning gas transport infrastructure. In February 2017, Gazprom proposed remedies to address EC objections by removing clauses that restricted re-sale of gas and offering its buyers to change delivery points ('swap deals'), to introduce competitive pricing benchmarks in its contracts and increase frequency of price revisions, and to not claim damages from Bulgaria regarding cancellation of the South Stream project. Following a market test, these commitments were made legally binding on Gazprom for eight years starting in May 2018.

Our analysis adds to existing *ex ante* modelling studies by investigating potential impacts of implementing Gazprom's commitments on CEE and North-Western Europe (NWE) gas markets. We found that Gazprom's commitments and, in particular, possibilities for its CEE customers to change delivery points to new locations may substantially limit Gazprom's potential market power in these markets. This would facilitate regional price convergence and offer a rather efficient way to connect CEE to more liquid markets in NWE. Thus, our results support the EC's conclusion that 'swap deals' facilitate further market integration in CEE, while limiting Gazprom's potential market power there. But *"the devil is in the details"*.

First, although swap deals improve market efficiency in CEE by limiting Gazprom's strategic behaviour, they do not improve total social welfare—by acting strategically, Gazprom reduces supplies to CEE, and, while swap deals increases those supplies in CEE close to the level of competitive benchmark, they do so by 'pulling' additional, more expensive, LNG into Europe. This results in loss in welfare for Europe overall. Thus, political solidarity between NWE and CEE has an economic cost when the dominant supplier, Gazprom, withholds supplies even to rather small CEE gas markets.

Secondly, although the ability to change delivery points may have a positive impact on market efficiency in CEE, it also poses policy challenges, namely, gas diversification and energy security for CEE. Swap deals may decrease Gazprom's market share at the expense of its other buyers entering the CEE markets, but this is 'contractual' diversification rather than the physical diversification desired by some CEE countries (e.g., Poland and Lithuania), because swap volumes are still Russian gas.

Indeed, most CEE investments in gas infrastructure (planned or realised) are meant to diversify their gas supply portfolios as well as give them an economic advantage in negotiations with dominant gas suppliers over terms of gas imports and trade. Our modelling results confirm the importance of LNG import terminals (e.g., Klaipeda and Świnoujście) and supply diversification pipelines (e.g., IGB bringing Azeri gas to Bulgaria). They serve as a hedge against Gazprom's strategic behaviour—when Gazprom exercises market power our modelling shows increased utilisation of these gas infrastructure projects. Further, we show swap deals do not substantially affect project utilisation when Gazprom acts strategically.

Since the 2009 Ukraine gas transit disruption, European authorities and MS regulators have been working to prevent a repeat of disruptions by ensuring all cross-border interconnection points have physical reverse capability. Our modelling underscores the importance of having such capability: we found reverse flow from Germany may be effective in putting competitive pressure on Gazprom's supplies into Poland and the Baltics. In fact, when Gazprom exercises market power, Poland becomes a transit hub, transporting gas from Germany to the Baltics. Further, bi-directional flow capability enhances cross-border gas trade in the Baltic region. Thus, in addition to having direct access to the LNG market, which has been the paramount goal of gas diversification policy for many CEE and Baltic states, more interconnected markets become critical in case Gazprom acts strategically by withholding supplies to increase its revenue.

The flipside is that LNG and interconnection in the Baltics increase regional gas security of supply in case of gas flow disruption from Russia. In this regard, access to LNG markets via import terminals at Świnoujście (PL) and Klaipeda (LT) is essential but insufficient to counterbalance Gazprom's strategic behaviour; the region should also be well interconnected with bidirectional flow capability. In practice, this means that national regulatory authorities should ensure non-discriminatory access to gas infrastructure for all suppliers not just their national gas suppliers (e.g., suppliers in Latvia should be able to book capacity in Polish LNG terminal but also capacity to bring that LNG back home via LT/GIPL or indeed German suppliers having non-discriminatory access to reverse capacity to bring gas into Poland and further up north to the Baltics when needed).

Further, well interconnected markets in CEE and the Baltic region is important not just for security of supply but they also ensure that the proposed swap deals are utilised in the most efficient way—this is because swap deals allows gas flows in Europe to be re-optimised in response to Gazprom's strategic behaviour and thus well interconnected markets allows for this flow optimisation. This is evident from our modelling where swap deals allowed trade and counter-trade between various markets in CEE, Baltics and NWE.

While our modelling show that in the next five years swap deals could have a marginally negative impact on utilization of CEE strategic assets, there is a risk that, once Gazprom's commitments expire in mid-2026, utilization of these strategic assets will fall considerably, especially if Gazprom withhold supplies to CEE and the Baltics. This may have 'unintended' consequences in terms of disintegrating CEE and Baltic markets from the rest of Europe. For example, GIPL interconnector's utilization rate falls dramatically should Gazprom withhold supplies to the region; absent swap deals, utilisation will not improve. This potentially means an increase in the cost of using the gas system in the CEE because the European regulatory model socialises gas assets and gas tariffs might not be cost reflective (see Chyong, 2019). The cost of cross-border trading between these small markets and the rest of Europe would then be hampered by these additional costs.

Thus, the only unambiguously positive outcome of the commitments is the certainty that Russian gas prices will become more competitive once priced against competitive NWE against NWE competitive benchmarks, and the socialised cost of gas systems (which would then include all strategic assets deployed against Gazprom's monopoly power). It is a vicious circle in the sense that these projects were publicly financed for security reasons in the expectation they would be used should Gazprom exercise its market power. Now that Gazprom has committed for a short period of time (until mid-2026) to changes to its contractual and sales practices to ensure competitive markets and prices, these assets will not be utilised or they will be utilised much less than envisaged, but the costs still need be allocated to all users of their gas systems beyond the commitment period.

More generally, in light of declining gas demand relative to the size of the gas systems and the widely divergent competitive landscape across European markets, our results reveal fundamental challenges in completing the project of a single European market for gas in the next decade. Addressing these challenges may require further gas market reforms, particularly, the current market design for gas transportation: potential policy options range from retaining the existing entry-exit regime to more drastic reforms such as redefining market zones with a gradual shift to nodal pricing. Ultimately, achieving the most efficient tariff structure goes far beyond a narrow discussion around security of gas supply since establishing efficient price signals will allow our energy system to be fully decarbonised at least cost.

The Energy Efficiency Gap in the Rental housing Market: It Takes Both Sides to Build a Bridge

Xavier Lambin,[a] *Joachim Schleich,*[b,c,d] *and Corinne Faure*[b]

There is ample evidence that households and organizations paradoxically fail to invest in energy efficiency (EE) measures that would be profitable for them based on net present value calculations.

To explain this phenomenon in the context of rental housing, most of the existing literature investigates investment inefficiencies after a tenant and a landlord have matched and signed a leasing contract. In particular, the literature on split incentives often assumes that when considering investing in EE, a landlord takes her tenant's characteristics as given, but in reality this is rarely the case. The lifetime of EE investments is typically much longer than a tenant's average tenure. Therefore, when landlords make EE investments, they do not have perfect information about current or future tenants' energy consumption. This information asymmetry on the tenant side has not been considered in the literature so far and, as we show in this paper, is also a source of inefficiency whenever landlords pay at least part of a dwelling's energy expenditures. Indeed, about 10% to 30% of rental contracts in developed economies still include at least some portion of the associated energy expenditures. Reasons include costs of the meters and of metering, lack of information, behavioral biases, or landlords' marketing strategies.

To analytically explore the role of informational frictions in the rental housing market, this paper develops a simple theoretical model which allows for information asymmetries on the side of landlords (i.e. dwellings) and of tenants (i.e. energy consumption). The model confirms that when the characteristics of both tenants and landlords are unobservable, EE investment is on average too low compared to a situation without such market frictions. When landlords' characteristics are observable - e.g. through Energy Performance Certificates (EPCs) - matching is efficient in the sense that energy-efficient landlords are matched with high-consumption tenants. However, investment in EE is still suboptimally low when landlords pay some or all of the energy expenditures. Similarly, when tenants' characteristics are observable, but landlords' characteristics are unknown, matching is efficient, but investment in EE is too low unless landlords pay the entire energy expenditures.

Thus, our theoretical model shows that the EE paradox may be attributable not only to the lack of signaling regarding landlord-side information but also to the lack of signaling regarding tenant-side information. Data from an original survey of landlords in Germany provide some empirical support for the relevance of disclosing information about tenants.

Our study confirms that when effective EPCs are in place policies encouraging individual metering go in the right direction, because these enable landlords to exclude energy expenditures from the rent and implement consumption-based billing. However, because various market frictions cause many rental contracts to still include energy expenditures, signaling the tenant type is also

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needed. In particular, because EE investments are often made when a landlord is searching for a new tenant, tenants should be able to signal their preferences for energy performance. Ideally, tenants would be encouraged to show their past energy bills to potential landlords. This could form the basis of an "energy passport" wherein tenants would record their past energy performance and other characteristics relevant to forming a prediction of their future energy use. This would be the tenant-side counterpart to EPCs. In most rental housing markets, landlords already gather some information about potential renters (credit checks in particular). In Germany (where the empirical study was conducted), potential renters are often asked to fill in a voluntary self-descriptive questionnaire including questions about rent payment capacity but also about being a good caretaker and a good neighbor. Further, in many countries, landlord associations have launched "ratemytenant" initiatives in which they gather and share information about their tenants (see for instance the site myrental.com in the USA). These questionnaires and websites could be expanded to include information about energy consumption.

Investing in Bridging Fuels: The Unit Commitment Problem of Public vs. Private Ventures

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Greece is gradually being transformed into an important energy hub of Southeast Europe supported by the development of big power and gas infrastructure projects and the introduction of the Target Model. Moreover, the continuing privatization process in the domestic energy market and the establishment of the Hellenic Energy Exchange are anticipated to enhance cross- border electricity trading and foster competition. The decision to completely decarbonize the Greek electricity sector until 2023, provides an additional incentive for a significant growth of natural gas as share of Greece's total electricity generation. Those radical changes in the electricity market assist the investment in new Combined Cycle Gas Turbines (CCGT) units that are currently under way.

This paper contributes to the growing literature on individual case studies by presenting an extensive comparison between public and private natural gas-fired units in managing the unit commitment problem in Greece. The aforementioned developments signal the importance to analyze and compare the efficiency of the existing public and private gas-fired power plants in Greece and derive important policy implications. By utilizing a unique hourly dataset, which spans from 2015 until 2019, we seek to identify which of the two groups under examination achieved to minimize imbalance costs, and in parallel, maximize profits. To our knowledge, none of the previous studies from the existing literature have analyzed this subject under this scope since our approach is the first to implement the well-known Cash Flows at Risk (CFaR) and Risk Weighted Returns (RWR) methodologies.

The first empirical finding, considering the period under examination, reveals that public units significantly outperformed compared to private units. Even though private units achieved

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accounts for the actual generation is included, public firms demonstrated superior results. In parallel, private units are obliged to pay higher imbalance costs compared to public units. However, following natural gas market liberalization in 2018, we observe a significant increase in terms of private units' efficiency. The second empirical finding of our study indicates an increase of efficiency throughout the years for both public and private units, yet the latter group achieved it at a considerably greater pace. The growth projections of our main profitability indicator (Index1), provide a clear indication that, following 2019, private units are anticipated to dominate over public ones.

The above findings derive important implications for both policymakers and market participants. First, the dominance of public units reveal that the role of PPC should be revised during the decarbonization period, since it is irrational to impose a share reduction in an efficient company that mainly uses CCGTs units compared to lignite ones. Second, we identify room for improvement in terms of private CCGTs units during their daily operation, given that higher operational efficiency throughout the bidding procedure is translated into increased social welfare via a reduction of the system marginal price and profit maximization.

The Negative Pricing of the May 2020 WTI Contract

Adrian Fernandez-Perez,[a] Ana-Maria Fuertes,[b] and Joëlle Miffre[c]

On April 20, 2020, the day before it was due to mature, the price of the NYMEX WTI crude oil futures contract (known as the May 2020 delivery contract or CLK20) tumbled to -$37.63. This was the first time that a WTI futures contract had experienced a negative price since NYMEX WTI trading began almost 40 years previously. The purpose of this article is to investigate the plausible reasons behind this unprecedented event.

In early 2020, the WTI futures market steered into a super contango due to demand shattered by COVID-19 lockdowns and supply exacerbated by geopolitical tensions. The super contango in turn incentivized cash and carry (C&C) traders to open long positions on CLK20 and short positions in more distant contracts, while simultaneously booking storage at a facility in Cushing (Oklahoma), the delivery hub of NYMEX WTI futures contracts. In this research, two pieces of evidence corroborate the idea of increased participation among C&C arbitrageurs in March and April 2020. First, we note that the futures-spot spread at that time exceeded the cost of financing and carrying the spot asset, and thus C&C arbitrage was profitable. Second, we demonstrate that increases in crude oil inventories at Cushing, in response to the widening of futures-spot spread, were 4.3 times higher in March and April 2020 than had been historically. Both pieces of evidence shed light on the lack of storage capacity at Cushing that prevailed before the negative pricing.

On April 20, 2020, or one day before the maturity of CLK20, the large number of open positions combined with the lack of storage at Cushing contributed to create an unprecedented problem of illiquidity. Long CLK20 traders who had not secured storage at Cushing had to either pay an exorbitant cost for storage, if any free capacity was still available, or close their positions at any price. In the end, they chose to close their positions at negative prices. Among the aggravating factors were i) the staggering margin calls that long traders inexorably had to pay as the price of CLK20 fell and ii) the likely price distortion and market abuse that occurred as a consequence of the trade-at-settlement (TAS) mechanism.

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Even within one day after the negative price event, some energy market commentators had blamed index traders for distorting the price of CLK20. The line of reasoning that these market pundits advocated was simply that by rolling their long CLK20 positions to more distant contracts, index traders had triggered the negative pricing of CLK20. We demonstrate the lack of veracity of these claims in reference to the United States Oil fund, the largest WTI crude oil exchange–traded fund, by showing that its flows did not influence either the return or the change in volatility of CLK20. We also show that the rolling of large, long index trader positions on prespecified dates ahead of maturity did not impact the futures-spot spreads in March and April 2020, and thus did not trigger further C&C trades or contribute to the observed negative pricing.

Among the practical implications of this research are lessons to traders with long front-end positions right before maturity, calling them to exert caution in super-contangoed futures markets, since at maturity the long position can suddenly become unfeasible if the asset cannot be physically stored. Our findings thus call for regulators to monitor the long positions of traders close to delivery so that they do not dislocate the natural convergence of the futures and spot prices at maturity. To ensure the integrity of the TAS pricing mechanism, it might be of interest for regulators to limit the netting of speculative TAS positions with speculative outright positions during the contract delivery month.

Compensating Solar Prosumers Using Buy-All, Sell-All as an Alternative to Net Metering and Net Purchasing: Total Use, Rebound, and Cross Subsidization

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Net metering (NM), currently used by 40 US states, compensates owners of solar PV systems who generate more electricity than they consume by crediting solar generation at the retail rate. However, there is increasing pushback to NM from electricity providers who argue that NM does not reflect the value of solar (VOS) to the utility. A cost-reflective rate would measure VOS as it affects electricity system generation, transmission, and distribution, operations and maintenance, and environmental attributes (Brown and Sappington (2017)). Furthermore, household solar generation is intermittent and not under the control of the electricity dispatcher, which requires ancillary services such as backup generation and technology to stabilize electricity system frequency and voltage.

To date, there is very limited empirical evidence on how solar pricing using NM affects electricity use, much less alternatives to NM. Given the resistance by solar proponents to replacing NM, the alternatives so far have attempted to maintain simplicity, while trying to address the utility-side concerns that solar customers are not paying enough to cover capacity costs and that prices do not reflect VOS, and the related fairness issue that non-solar customers are experiencing higher bills given the smaller contribution by solar customers.

Austin Energy is the first US electricity provider to replace NM with Buy-All, Sell-All (BASA), also known as Gross Metering (GM). BASA requires separate metering of solar generation and electricity consumption. Separate metering allows the provider to pay a different rate for solar generation than the customer pays for purchases from the grid. Under BASA, the customer buys all

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of its electricity from the utility at the retail rate and sells all of its solar-generated electricity to the utility at the VOS rate; the household can no longer self-consume its solar generation.

Net purchasing (NP) is another mechanism that is similar to NM, in that customers can consume what they produce, only buying from the grid when their total electricity consumption exceeds their solar generation. But like GM, there are separate meters to track solar sold to the electricity provider vs. electricity purchased from the grid. The electricity provider can pay a different rate for the net exports than the rate it charges for electricity from the grid.

We develop a theoretical model to compare rates and cross-subsidization under the three mechanisms. We also incorporate the increasing block rate structure employed by Austin Energy. We derive propositions that shape our empirical analysis. Our model suggests rebound effects and cross subsidies for NM and NP but not for GM.

Pecan Street Dataport provides detailed data for a sample of Austin Energy customers, with a focus on the Mueller Street neighborhood where there is a high concentration of solar adopters. We examine customer load curves to gain intuition into the differences in energy consumption between solar and non-solar customers for varying home sizes. We then use regression analysis to compare total electricity consumption for solar and non-solar customers in the Mueller Street sample. In particular, we consider whether solar generation (and compensation for generation) results in a rebound effect, whereby solar customers increase their total electricity consumption as compared to non-solar customers. Finally, we simulate customer bills under BASA and compare them to NM and NP. We compare customer bills under the three rates as well as cross-subsidies between solar and non-solar customers.

The load curve comparisons suggest that solar PV customers have higher consumption than non-solar customers during late afternoon and evening hours. We find from the regression analysis that solar customer air conditioning use, but not total use, is sensitive to the size of solar credit they receive. An increase in solar generation of 10 kWhs, resulting in a solar credit of about \$1, increases air-conitioning electricity consumption by about 2 kWhs, a 20% effect. We interpret this as a rebound effect with a similar magnitude to that found by Deng and Newton (2017), who examined a GM rate in Australia.

The simulations show that net metering and net purchasing typically result in lower consumer bills and larger cross- subsidies than BASA, with almost 18 percent of bills of net metered and net purchasing prosumers paid by non-solar customers. But the comparisons depend on the structure of the tiered retail rates for all three rates as well as the rate paid for for solar under NP and GM. Finally, we simulate a flat rate in place of an increasing block rate, which reduces cross-subsidies to under 7 percent.

Volatility Forecasting of Crude Oil Market: Which Structural Change Based GARCH Models have Better Performance?

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GARCH-type models have been widely used for forecasting crude oil price volatility, but often ignore the structural changes of time series, which may lead to spurious volatility persistence. However, when we focus on relevant research in the crude oil market, it can be found that most of

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existing methods can only recognize the abrupt structural changes caused by strong external shocks, but they hardly recognize the smooth structural changes caused by the slow response to external shocks. But in other financial markets, some relevant research have found the presence of smooth structural changes in the varying price series and recognized that the flexible Fourier form (FFF) GARCH models can capture various degrees and forms of structural changes in light of different external shocks.

Therefore, it is necessary to apply the FFF-GARCH-type models considering smooth shift to crude oil price volatility modeling and forecasting. Specifically, this paper focuses on the smooth and sharp structural changes in crude oil price volatility, i.e., smooth shift and regime switching, respectively, and investigates which structural change based GARCH models have better performance for forecasting crude oil price volatility.

The empirical results indicate that, first, the flexible Fourier form (FFF) GARCH-type models considering smooth shift can accurately model structural changes and yield superior fitting and forecasting performance to traditional GARCH-type models. Second, the Markov regime switching (MRS) GARCH model incorporating regime switching exhibits superior fitting performance compared to the single-regime GARCH-type models, but it does not necessarily beat the counterparts for forecasting. Finally, the FFF-GARCH-type models outperform MRS-GARCH for forecasting crude oil price volatility and portfolio performance, indicating that compared to regime switching, the incorporation of smooth shift can better capture structural changes, thereby improving the forecasting accuracy of GARCH-type models.

The conclusions above have clear policy implications for modeling the volatility in crude oil market. In particular, for energy economists, energy policymakers and energy market practitioners, they can consider the smooth shift to identify the various degrees and forms of structural changes in crude oil price volatility more efficiently, in such a way to generate more accurate volatility forecasting results and make more accurate strategic decision. In addition, the incorporation of regime switching does not perform significantly better than the single-regime GARCH models when they are used to forecast crude oil price volatility, and it is not necessary to prefer the complicated models.

Household Solar Analysis forPolicymakers: Evidence from U.S. Data

Rohan Best[a] and Ryan Esplin [b]

Prior research on household solar-panel adoption has reached a range of conclusions. There are differing results for multiple important explanatory variables including income, age, race, and education. Greater understanding of these influences has substantial potential for enhancing the policy process, as subsidies for solar systems are increasingly referring to variables such as income. More targeted policy support can help to promote emissions reduction more efficiently through lower subsidy spending for a given level of solar-panel adoption that substitutes for fossil fuels. Energy insecurity for households can also be reduced more efficiently through more precise identification of which households face the most binding constraints for solar-panel adoption.

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This paper uses the 2019 American Housing Survey to give a large sample that is representative of the United States (U.S.). We use multiple methods to assess the impact of key socioeconomic variables on residential solar-panel adoption. These include logit and probit models to account for the dichotomous nature of solar-panel uptake, a linear probability model for further assessment of robustness, and entropy balancing to justify causal interpretations of the results. We progressively add key explanatory variables to the regression models to assess the impacts for debated influences on solar-panel adoption. Interaction analysis supports the baseline regressions. Subsample analysis is also conducted to uncover similar results for key groups.

The key conclusions of the paper include the important impacts of wealth and age on solar-panel adoption. Higher housing wealth and older age are generally associated with greater solar-panel uptake. These results are robust across each of the methods employed. The impact of wealth is an often-omitted influence for household-level studies of solar-panel uptake that is shown to be crucial in understanding the influence of other aspects such as education, income, and race. The wealth influence is consistent with economic theory, as the upfront capital constraint is more difficult to overcome for households with lower levels of wealth. The paper also finds some evidence that public housing tenants are more likely to have access to solar panels than private tenants.

In contrast to recent policy approaches that have increasingly been based on income targeting, our analysis suggests that wealth thresholds will be considerably more effective in identifying constrained households who require policy assistance to obtain solar panels. There are likely to be major benefits from data collectors including components of wealth in future household surveys.

The Economics of Demand-side Flexibility in Distribution Grids

Athir Nouicer,[a] Leonardo Meeus,[b] and Erik Delarue[c]

The Clean Energy Package (CEP) Directive (EU) 2019/944 calls on the Member States to develop regulatory frameworks that incentivize Distribution System Operators (DSOs) to consider the use of flexibility as an alternative to network expansion. DSOs will have to develop and publish network development plans that consider the trade-off between flexible resources and system expansion. The CEP also includes demand-side flexibility as a new network code area, recognizing the need to elaborate on a regulatory framework for demand-side flexibility.

Demand-side flexibility can be implicit, i.e., reacting to pre-defined price signals to which all consumers are subject, or explicit, i.e., flexibility, offered by a consumer or requested by the DSO, is paid a given price. This paper focuses on mandatory curtailment by the DSO with compensation. We develop a long-term bi-level equilibrium model. In the upper level, the regulated DSO optimizes the social welfare by deciding on the network investment and/or curtailing consumers, as well as setting the network charge level to recover network and flexibility costs. Consumers, prosumers or passive consumers, maximize their own welfare in the lower level. The DSO anticipates the consumers' reaction when investing in the network and when setting the flexibility level.

We assess to what extent explicit demand-side flexibility mechanisms can complement the implicit incentives. If network tariffs are somewhat cost-reflective, prosumers investments in PV and batteries internalize the cost of network investments. Explicit demand-side flexibility, used in

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combination, allows the realization of higher welfare gains. If network tariffs are too imperfect, it can become relatively cheaper to overinvest in the network than to correct the resulting consumer profiles with curtailment. We also found that it will be challenging for regulators to set an appropriate level of compensation for curtailment. When the compensation is below the Value of Lost Load (VoLL), passive consumers are only partly compensated for their loss. If the compensation is increased towards the VoLL, it becomes so attractive for prosumers that they game the system. They start to use their batteries against system needs, anticipating that they will get curtailed and compensated.

Revisiting Energy Subsidy Calculations: A Focus on Saudi Arabia

Anwar Gasim[a,b*] *and Walid Matar*[b]

The global debate surrounding fossil fuel subsidies has become more contentious due to climate change. Many governments offer subsidies in the form of below-market energy prices to spur industrialization and support lower-income households. While some governments do this through direct transfers to producers or consumers, other governments forgo revenues that could have been attained from selling energy at higher prices instead. Countries that fall in the latter category are typically energy exporters that experience large rents.

After reviewing various definitions of energy subsidies, we adopt one that compares an oil exporter's domestic energy prices with its costs, including opportunity costs. Applying this definition along with exhaustive energy price and quantity data, we estimate the magnitude of Saudi Arabia's energy subsidies from 2007 to 2018, a period that encompasses rapid domestic socio-economic growth and two waves of energy price reform.

We first apply the conventional price-gap method, where the price gap is some fixed reference price minus the domestic price. If a fuel is traded internationally, its market price is used as the reference price. If it is not, then the production cost is used instead. We find that total energy subsidies peaked in 2012 at 85 billion 2019$ (2019 U.S. dollars), with crude oil, diesel, and gasoline constituting 70% of the total. In 2016, as global oil prices fell and the first wave of energy price reform kicked in, total energy subsidies declined to 39 billion 2019$. The second wave in 2018 mainly reduced electricity and gasoline subsidies, although total energy subsidies increased to 47 billion 2019$ due to a recovery in international oil prices.

However, the price-gap method does not consider how subsidy removal affects domestic consumption, fuel exports, and international market prices. For example, removing the crude oil subsidy in Saudi Arabia would reduce domestic crude oil demand, freeing up more crude oil for export. The resulting increase in supply on the international market will depress global oil prices, thus reducing the newly reformed domestic crude oil price, which would now be directly linked to the international price. A lower domestic crude oil price would alter domestic demand and exports again. This process would repeat until a new equilibrium is reached.

In this vein, we propose a method for calculating the implicit subsidy that accounts for these market responses. The implicit subsidy, or foregone revenue, consists of the revenue obtained from selling the fuel locally and globally at the new international market price, minus the lost revenue on the initial exported quantity that is now sold at the new relatively lower international mar-

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ket price. If domestic demand does not respond to higher prices, and thus there are no additional exports, our method collapses to the simple price-gap equation.

Our method demonstrates that the magnitude of total energy subsidies in oil exporters such as Saudi Arabia, in which a large share of subsidies represents forgone revenues, may be considerably lower than the value estimated by the simple price-gap method. For instance, the implicit crude oil subsidy in 2018 amounted to $8.6 billion using the price-gap method. If the short-run domestic price elasticity of crude oil demand is -0.06 and Saudi Arabia exported all the domestically saved crude oil (due to subsidy removal), we demonstrate using our method that the crude oil subsidy would fall to around $4.6 billion, 46% smaller than the price-gap estimate.

This study contributes to the literature in several ways. We not only provide comprehensive estimates for energy subsidies in Saudi Arabia by fuel and over time, but we also introduce a method that produces more realistic estimates of implicit energy subsidies for oil-exporting countries. Given that our method only requires ex-post information about the past and little additional data, it can add significant value to future studies of global energy subsidies.

Manufacturing in a Natural Resource Based Economy: Evidence from Canadian Plants

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Since the 1980s, myriad studies have investigated the oil price shock impacts on the economic performance in oil-exporting countries. However, the theoretical and empirical research on understanding the responses of firms to oil price shocks is limited. While most studies have focused on aggregate or sectoral analysis, only recently have researchers begun to examine the firm level impacts of the oil price shocks, thanks to the availability of large-scale micro data. The firm level studies allow us to examine the heterogeneous responses of firms to the oil price shocks based on their individual characteristics, which can aid to understand how regional economies perform generally after the boom. They will also provide better understanding of the diverse evidence on total employment and trade effects.

In this paper, we contribute to the literature of oil price shock effects on economic performance by first developing a theoretical model to analyze firm level outcomes in economies affected by a resource sector, and second, by conducting an empirical analysis using a large firm level dataset. Our general equilibrium model with heterogeneous firms and a natural resource sector allows us to understand how different firms respond to oil price shocks based on their given productivity. Relative to other studies setting out heterogeneous or productivity differentiated firms, we therefore leave behind the classical dichotomy of a traded and non-traded sector suggested by Dutch disease model. The model assumes a resource boom as an increase in the oil price or an increase in total factor productivity in the oil sector, which prompts a reallocation of labor from manufacturing firms to the oil sector. It further allows a geographical factor to interact with these dynamics. Specifically, the oil sector pays a wage premium over the wage of the manufacturing sector, which is largest for firms that are in the same locality as the oil sector and diminishes with distance.

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We derive a number of predictions that reflect the interaction between the resource sector and the firm's performance including the export decisions, wages, and employment. For instance, the model predicts how a firm's choice on exporting responds to a resource boom, which after aggregating to a sectoral level gives an endogenous expansion of non-trading firms. Additionally, in contrast to other studies using firm-level data, we look at the export performance of firms affected by natural resource sector development. Specifically, our model suggests that while wage rate and domestic sales increase for a given firm, only most productive firms continue to export. Also, employment increases in a given non-exporting firm, but the effect is ambiguous for exporting firms. All these effects are attenuated by a distance parameter, allowing for a differentiation between geographies.

As a case study, we take the predictions of the model to a rich Canadian data source. Canada is a developed country with well-diversified economic activities across its provinces. Specifically, major oil extraction facilities are located in the western province of Alberta, while the eastern provinces of Ontario and Quebec are the major producers of manufacturing products. However, the oil and gas produced in Alberta are almost exclusively exported, mainly to the United States. In this sense, the Alberta oil industry is exemplary case of a booming sector that generates a local foreign exchange windfall. From the Annual Survey of Manufacturers (ASM) of Statistics Canada, we obtained yearly plant level data of all manufacturing plants in Canada from 2000 to 2010. We estimate the relationship between economic performance of each plant and time-varying revenues in the natural resource sector and cross-section varying distance of each plant relative to Ft. McMurray, Alberta, as the main hub of the oil extraction activity. We find that on average plants tend to be negatively affected by a boom in the natural resource sector in terms of employment, total revenue, productivity and exports. However, there exists a great heterogeneity in plants' responses, indicating that some plants actually do rather well. We cannot attribute this effect exclusively to the tradability of the produced output or industry linkages. Instead, we find that plants that have above average levels of productivity at the beginning of the sample period do relatively better and increase their exports in response to the resource boom.

The interaction between a resource extracting sector and manufacturing remains an important area for research. This paper indicates that plant level productivity can be an important explanatory channel to understand how firms, rather than sectors, respond to a resource boom. Relatively high productivity plants appear better able deal with shock in the resource sector. Policies aiming to prepare regional economies to the transition away from fossil fuels would do well to take account of the productivity of plants, rather than solely their linkage to the resource sector.