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Prices Behind the Meter: efficient economic signals to support decarbonization

1. Introduction

The electricity consumer is critical to the success of decarbonization. Yet, the economic signals that consumers receive in many countries are likely to discourage efficient decisions and could slow decarbonization or unnecessarily raise the costs. This paper emphasizes the importance of encouraging only efficient consumer decisions, in particular with respect to investment and use of distributed energy resources (DER) behind the meter (BTM). It focuses on eliminating existing price distortions in certain liberalized electricity markets in the European Union (EU) and on creating or changing markets to reflect new economic and technological conditions.

Section 2 introduces the analytical framework. Sections 3 to 7 identify a number of economic signals that will raise the cost of decarbonization or slow down the energy transition. For each, the paper makes proposals to improve economic signals. Section 8 summarizes the recommendations.

2. Efficiency objectives

The liberalized electricity industry structure was designed in England and Wales in the early 1990s and then adopted elsewhere, including in the EU. A key feature of the liberalized structure was that prices would reflect the efficient economic cost of supplying electricity. There were three specific efficiency objectives.

- *Operating efficiency*: Energy-only markets were designed to provide incentives to replicate the existing cost-based merit order dispatch, using a price-based dispatch to ensure that the cheapest generator available at any time was dispatched.
- *Allocative efficiency*: Governments dropped most price controls on electricity. This reduced subsidies and cross-subsidies as generators and retail suppliers tried to avoid selling at a loss. As a result, prices tend to reflect marginal costs.
- *Dynamic efficiency*: A key aim of liberalization was to transfer investment risk to investors, and thereby sharpen the incentives to make efficient decisions. Previously, investment decisions were typically made by government or regulated companies, with the costs and risks passed to consumers. This often led to expensive and inefficient decisions, the costs of which were passed to consumers. Liberalization aimed to stop this practice.

Liberalized markets in the EU have functioned reasonably well on the first two types of efficiency, but less well on the third. There has always been a concern about 'missing money', that is the inability of the 'energy-only' electricity market to generate sufficient revenue to recover investment costs. Some systems introduced administrative capacity payments or markets to ensure sufficient capacity was built, or that the mix of generation was acceptable. Others, including many European countries, did not see

David Robinson

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the need for special arrangements to remunerate capacity because investment was either unnecessary or already forthcoming. In any case, even in the early stages of liberalization, there was no consensus that energy-only markets would deliver sufficient quantities of policy-compatible investment.

When climate change became an important policy objective, after 2000, governments were increasingly reluctant to leave investment decisions to the market. The need to address an enormous market failure was evident. In principle, governments could do so through the introduction of carbon taxes and other market-friendly measures. However, these have never been more than supporting measures. Carbon prices introduced through the EU Emissions Trading System (ETS) were too low to incentivize investments in low-carbon generation capacity, and were often too low even to change the merit order from coal to gas. Instead of adopting technology neutral market measures, governments opted for specific forms of support (subsidies) for renewables. This led to rapid penetration of solar- and wind-based electricity, contributing to the decline in the cost of those renewables. This penetration effectively broke 'energy only' markets, which were designed for technologies with significant marginal (mainly fuel) costs, not for technologies with zero, or very low, marginal costs. The increasing penetration of renewables is now driving short-term energy prices down to levels that make investment in renewable and conventional generation unattractive in the absence of government support, which is increasingly provided through auctions (Keay and Robinson, 2019). Currently, there is no generally accepted 'exit' strategy to end subsidies and government control over investment, but there is a growing recognition that today's markets are not working as originally intended and will need to be reformed. (Keay, 2016)

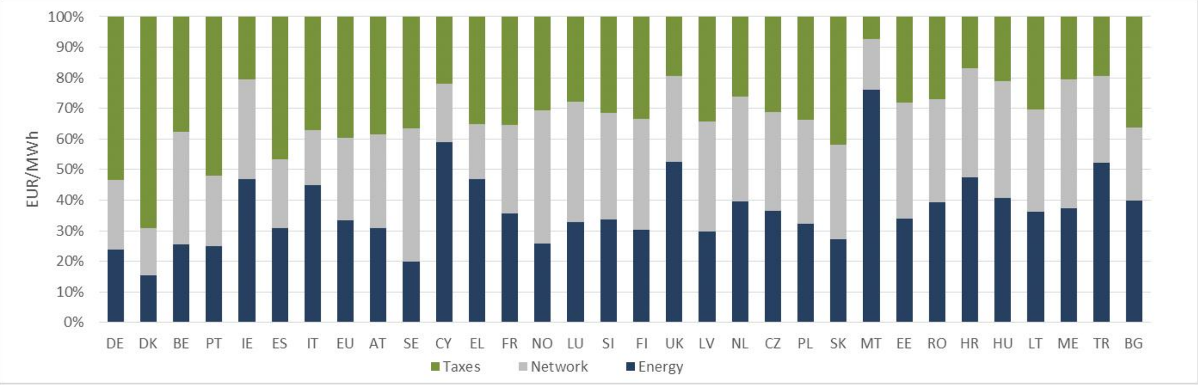
The accelerated decentralization of the electricity sector is introducing an additional dilemma. Distributed energy resources are key to renewable penetration and electrification, for instance through rooftop solar, battery storage, electric vehicles (EVs), heat pumps and more flexible consumption. On the other hand, current electricity markets, fiscal policy and regulations do not provide efficient price signals for BTM investment and operations. The next five sections examine ways to improve the efficiency of economic signals and thereby encourage BTM decisions that support decarbonization.

3. Fiscal policy reform

Governments in the EU and elsewhere typically use electricity tariffs as a revenue collection mechanism to finance public policies. The EU's accounting of electricity costs distinguishes three categories: (a) taxes and levies, (b) energy and (c) networks. Of the first, taxes, like value added taxes (VAT), fund general government expenditure, whereas levies usually fund specific policies, such as the promotion of renewables. Taxes and levies together are referred to below as the 'government wedge'; levies alone are also referred to below as 'policy costs'.

As Figure 1 shows, the government wedge accounts for an important share of final electricity prices in the EU. In Germany (DE), Portugal (PT) and Spain (ES), it accounted in 2017 for about 50 per cent of final prices, and in Demark (DK) for significantly more.

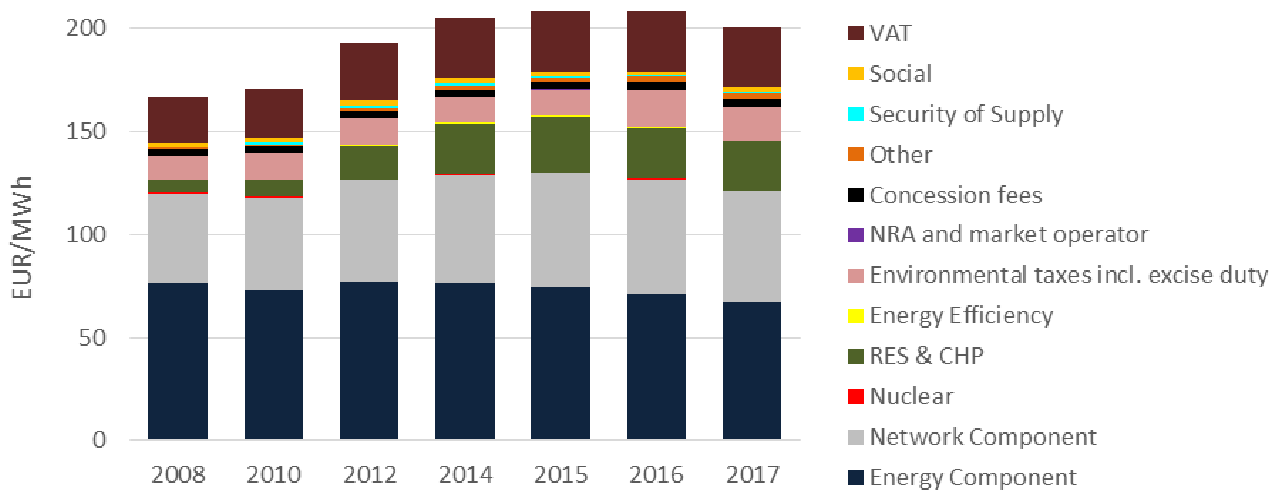
Figure 1: Composition of household electricity prices in 2017, EU member states



Source: EC (2019), page 32

Furthermore, between 2008 and 2017, the government wedge rose substantially in the EU, from 28 per cent to 38 per cent of the average final residential tariff. Figure 2 illustrates the changing composition of absolute final household electricity prices. While the combination of the energy and network components remained about the same, the government wedge increased noticeably.

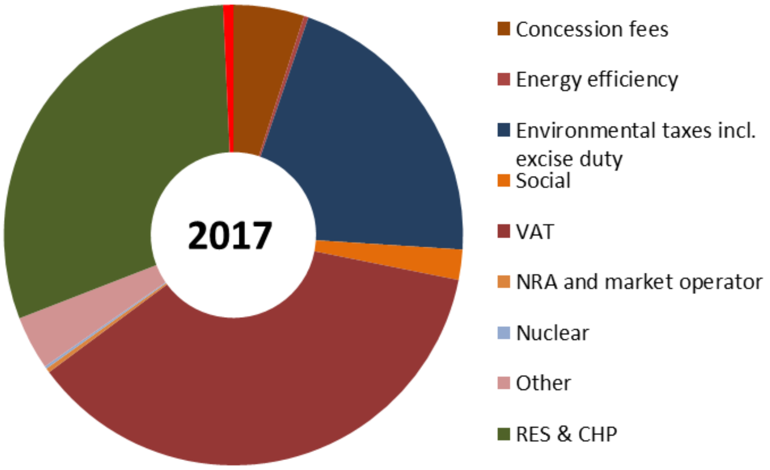
Figure 2: Composition of household electricity prices in EU 2008–17



Source: EC (2019), page 33

The main cause of rising electricity prices in the EU were the levies to finance the costs of renewable electricity (RES) and combined heat and power (CHP) that could not be recovered through markets. Combined, these levies rose on average from 14 per cent to 33 per cent of the government wedge between 2008 and 2017. Figure 3 illustrates the share of the different components of the government wedge in 2017.

Figure 3: Composition of taxes and levies on electricity in the EU 2017



Source: EC (2019), page 33

As a result of a rising government wedge, electricity prices today in many European countries are much higher than the incremental costs of supplying electricity. Consumers have an incentive to generate their own electricity to avoid paying taxes and levies. This avoidance reduces substantially the pay-back period on investment in roof-top solar power generation.

Who can blame consumers for wanting to pay less? The problem is that, when high prices reflect taxes and levies, the bypass is usually uneconomic from a system perspective, potentially creating serious economic problems that require policy reversals.

- *Uneconomic bypass*: The cost of rooftop renewables in areas with developed distribution grids is normally higher than the cost of large-scale wind or solar, even after taking account of the reduced system losses and other possible benefits of distributed generation. Regulated tariffs that do not reflect that difference will encourage uneconomic bypass of the system, raising system costs. Consumers may choose to generate their own electricity for other reasons, but should be given accurate information about the incremental costs of the alternatives. If they have the option to purchase renewable electricity from the system at lower costs than to generate it themselves, many are likely to prefer to purchase from the system.[1]
- *Barrier to decarbonization via electrification*: The government wedge is a barrier to decarbonization through electrification. Take heat, for instance. In many EU countries, the fiscal treatment of natural gas makes it more competitive than electricity. In Spain, for example, taxes and levies for natural gas are much lower than for electricity; this reduces the competitiveness of efficient electric heat pumps (for heating and air conditioning). Transport is another example. In Europe, the fiscal burden on transport fuels has been fairly steady over the past 20 years, while CO_2 emissions from transport have been rising. During the same period, the fiscal burden on electricity has risen noticeably and CO_2 emissions from electricity have fallen, mainly due to the penetration of renewables. Consequently, electricity is losing competitiveness to fossil fuels; this could slow the penetration of electric vehicles (Robinson 2017 and Robinson et al. 2019).
- *Policy dilemma:* Who will finance the government wedge if a growing number of consumers bypass system costs through investment in own generation? Poorer citizens who could not afford to invest in solar panels may end up subsidizing wealthier households. Alternatively, the government could force electricity companies to absorb the costs. A third possibility is that the

[1] Section 7 of this paper discusses a new market approach that would give consumers the opportunity to compare own-generation of renewables with purchasing renewable energy from the system.

> government would face a tariff deficit (revenues from regulated activities less than regulatory entitlements) that requires recovery of costs from future consumers. None of these options is politically attractive and the government might eventually need to withdraw the incentives for uneconomic bypass. However, this too would be very difficult. It would be far better to avoid or minimize the distortion from the outset.

What can be done to resolve these problems? The following solutions are all worth considering, with the first being superior to the others but very difficult to implement. The likely outcome will probably be some combination.

Pass the levies to the government budget

The best solution is to finance support for renewables and other public goods through general taxation. In the words of Newbery (2015),

> 'It thus follows that the revenue needed to finance renewables and other public goods should come from general taxation raised in the least distorting ways consistent with distributional objectives – either through income taxes or a uniform rate of VAT, and not by selectively charging single products like electricity.'

In practice, governments are reluctant to pass levies to the budget since this either creates a larger government deficit or requires the introduction of politically sensitive measures to raise taxes in other ways.

Share these costs with the oil and gas sector

Another solution is to share the policy costs with the oil and gas sector. There are two arguments for doing so. First, governments have promoted investment in renewable power in order to meet the European 2020 objective: 20 per cent renewables as a percentage of energy (not electricity) consumption. It seems reasonable that consumers of all energy products should share the cost of the financial support needed to meet this goal. The new EU renewables objective of 32 per cent provides further reason to share costs that cannot be recovered through markets; to not do so would raise the relative price of electricity and weaken the incentives for decarbonization via electrification. The sharing could be done by reference either to the emissions of each energy source or to a combination of energy content and emissions, as proposed in a draft EU Directive that was abandoned in the absence of a consensus.

A second argument in favour of sharing the costs is related to the 'polluter pays' principle. Currently, fossil fuels burned in electricity generation pay a carbon price determined in the market for carbon emission allowances under the EU ETS. But the EU ETS does not apply to emissions in most energy end markets, notably transport, industry and buildings. To ensure that the polluter always pays, some EU countries have introduced economy-wide carbon taxes. The carbon tax revenue could help to finance the cost of supporting RES/CHP, thereby reducing the levies on electricity prices. These proposals meet understandable resistance from the oil industry, which argues that its tax burden is already high, leading to heated debate about whether its taxes cover all environmental externalities and its share of the costs of the road transport infrastructure. Furthermore, raising transport costs can have macroeconomic impacts that need to be managed. Nevertheless, the case for sharing the support costs for renewables among all energies, for instance through an economy-wide carbon tax, is gaining strength (Robinson et al., 2019).

Limit the potential for a tariff deficit

A third option is to limit the freedom of consumers to sell self-generated electricity to the system. This restriction makes no economic sense once the distributed generation has been built, since the marginal cost of producing electricity is virtually zero. In any case, the system still loses levy revenue. Furthermore, this measure does nothing to address the other concerns, notably the disincentive for electrification.

Collect the remaining levy costs in a policy charge

If policy costs are recovered through tariffs, the best way to minimize distortions is to recover them through a fixed charge for all consumers connected to the system. Since the cost to be recovered is sunk and unrelated to future costs, the challenge is designing the policy charge to distort investment or consumption decisions as little as possible, subject to equity concerns. For instance, this charge could reflect a consumer's income, the contracted capacity or a combination. However, a high fixed policy charge could motivate disconnection from the system, with all the problems this would entail; that risk reinforces the case for eliminating levies from the tariff or reducing them as far and as soon as possible.

4. Redesigning network access tariffs

Before liberalization, network pricing was not a problem. Electricity companies needed to make a margin over their overall costs and it did not matter greatly where the costs arose. With liberalization, it became critical to understand the costs involved in the now separate functions of transmission and distribution and to reflect them properly in prices. With the challenges of decarbonization and decentralization, network access tariffs have become much more complex.

There are many important issues in defining network prices today.[2] The analysis below draws on a recent debate in Spain where the regulatory authority is considering what methodology to adopt for remunerating networks and for access tariff design. The analysis focuses on access tariff design, in particular providing efficient temporal signals and incentives for decarbonization via electrification.

Currently, regulated network access tariffs in Spain include a fixed component related to the consumer's contracted capacity (per kW) and a variable component related to consumption (per kWh), with some time-of-use (ToU) and seasonal variations. The current tariff design is problematic for at least four reasons[3].

- *Inefficient signals for network investment*: The fixed component reflects a consumer's contracted capacity, not the consumer's demand at times of *coincident system peak*. Consequently, tariffs do not provide signals to lower demand at system peak and therefore do not help to reduce or postpone future investment.
- *Inefficient signals for use of uncongested capacity:* Neither the fixed nor the variable elements of access tariffs provide a sharp enough signal to use the network when it is underutilized. This indirectly leads to greater use of the network during peak periods, creating the need for investment that could be avoided through better price signals.
- *Uncertain recovery of network costs:* Consumers are already reducing their contracted capacity; the resulting loss of revenue will grow in line with distributed generation and storage. Furthermore, a share of revenue comes through the variable charge, making revenue streams vulnerable to the loss of throughput.
- *Poor incentives to invest in electric vehicle (EV) networks and electrification:* The fixed element of the tariff discourages investment in EV charging networks, mainly due to the difficulty of recovering those fixed costs from the low volume of EV charging in the early years following investment. Furthermore, a high variable charge may discourage investment in electrical devices, such as heat pumps.

There are various reasonable alternatives to this tariff structure. The analysis below considers two extreme possibilities: one based almost entirely on fixed payments for contracted capacity (kW) and the other based solely on variable payments for energy actually sold (kWh). Both extremes are unlikely

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[2] See Keay and Robinson (2017a) for a fuller analysis of the main policy issues related to network pricing, notably the importance of location signals.

[3] There is a fifth problem with network access tariffs in Spain, which is that they include an element ('cargos' in the Spanish legislation) to recover levies and a second element ('peajes') to recover network costs. Really, the two components should be dealt with together, but that is not the case in Spain. The government is responsible for deciding how to deal with the levies ('cargos') and the previous section of this paper made suggestions on how to remove related distortions. The regulatory authority (CNMC) is responsible only for the remuneration of the network costs, including the design of the 'peajes'. This section only addresses the design of the 'peajes'.

today, but the analysis helps to understand the pros and cons of the alternatives being discussed and the preferred direction of change. Since both approaches begin with the same assumed regulatory revenue entitlement (whether recovered through fixed or variable charges), the incentives for efficient use and expansion of the network, and for decarbonization, are especially important.

The aims of access tariff design include: using the existing network efficiently; incentivizing efficient investment decisions; recovering investment costs; supporting efficient electrification; and being sensitive to equity considerations.

Fixed charging approach[4]

Under this model, fixed costs are recovered through a fixed charge based on contracted capacity (per kW) and variable costs through a variable component (per kWh). Since approximately 80–90 per cent of network costs are fixed[5], under this model the fixed component is the main source of revenue. To provide ToU signals, this model has different fixed charges reflecting anticipated peak and off-peak time periods. Supporters of this kind of model argue that it: (a) promotes electrification, notably heat pumps, because of low variable electricity charges; (b) is predictable, similar to flat tariffs used in telecom, and therefore easy for consumers to understand; (c) involves no price shocks and related consumer anger; and (d) facilitates investment in EV charging networks due to the low off-peak fixed charge. On the other hand, this model raises some concerns.

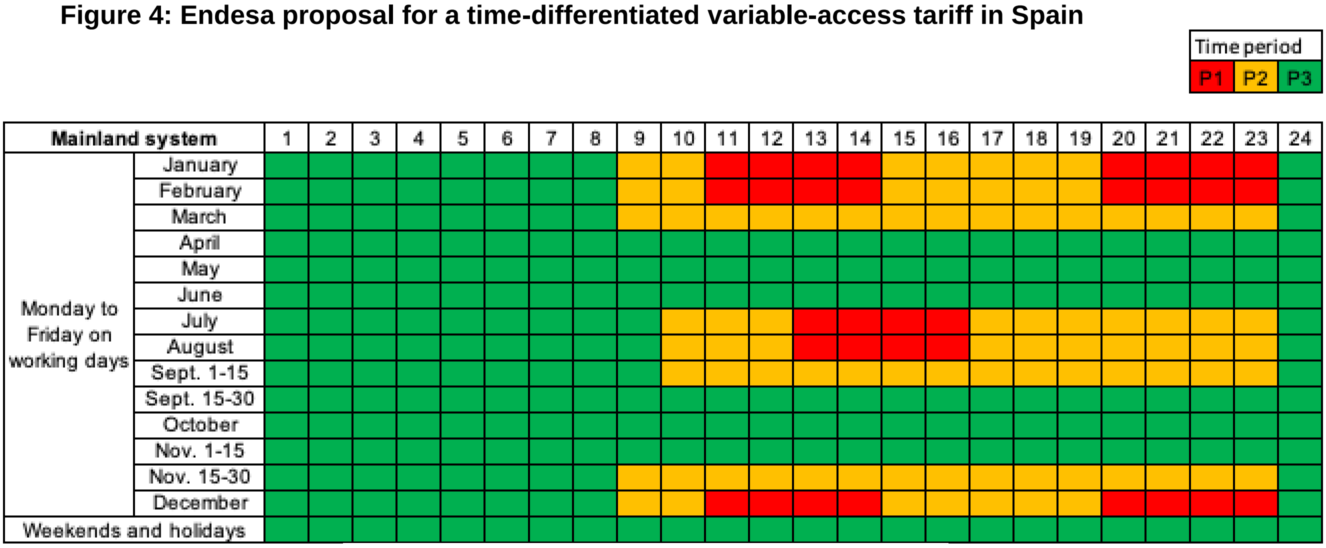
- *Poverty*: In most countries, it is politically unacceptable to levy a large fixed charge on small consumers if this means that poor consumers will be penalized. There is a debate about whether the poorest really are penalized by the fixed charging approach. The poor may consume a lot of electricity due to bad insulation and old radiators, while wealthier people may have alternatives that reduce electricity consumption from the system, including self-generation, gas and gasoil. In any case, the solution for energy poverty is a combination of direct public support, as well as more efficient buildings and heating systems (e.g. heat pumps), rather than distorted tariff designs. Nevertheless, it is important to ensure that new policies do not harm the most vulnerable consumers.
- *Fixed cost recovery in doubt:* If the fixed payment is based on contracted capacity, consumers will reduce the amount they contract, reducing the potential to recover fixed costs. This could be addressed by an annual regulatory 'true-up', although this is politically difficult to implement. In any case, incentives to reduce the need for capacity are a good idea.
- *Inefficient use of network:* This approach to pricing is not based on the actual use of the network, especially at peak times, and may not provide efficient incentives for its use. The incentives for efficient use will depend on how well the ToU tariffs reflect congestion.
- *Uncertainty about future congestion:* This model does not reflect the increasing uncertainty about network congestion, especially due to penetration of intermittent renewables and BTM activity.

Variable charging approach

A second approach recovers most or all costs through a variable payment related to hourly capacity demand (kWh) and ToU. Endesa has made a proposal for Spain along these lines, as reflected in Figure 4. It uses a road traffic-light analogy to identify three periods (p1 red, p2 yellow and p3 green). The tariff reflects the average capacity used in each period, which is equivalent to the energy consumed in each period.

[4] The case for the fixed charging approach in Spain is made in 'Que estructura de tarifa eléctrica es la adecuada para favorecer la transición energética?', in *Energía y Sociedad*, Boletín #188, 21 octubre 2019.
[5] This percentage can vary depending on the treatment of losses in each country.

Figure 4: Endesa proposal for a time-differentiated variable-access tariff in Spain



	Time periods		
	P1	P2	P3
Number of hours	672	1,479	6,609
Share of hours	7.70%	16.90%	74.40%

Source: Endesa

Green-light hours account for 70–80 per cent of hours, when congestion on the distribution and transport network is very low. During these hours, the variable charge would be very low to encourage utilization of the network. Yellow-light hours, possibly 15–20 per cent of the total, correspond to moderate congestion. Red-light hours**,** around 5–10 per cent of the time, correspond to heavy congestion periods when variable charges will be significantly higher.

These tariffs reflect low short-run marginal costs as well as congestion costs, which vary by time period, and allow for fixed cost recovery. They aim to encourage a shift in demand from peak hours to off-peak hours. By lowering the cost of network utilization in off-peak hours, the variable tariffs are consistent with the development of EV networks that are used during green hours. The advantages of this approach are: (a) efficient use and expansion of the network; (b) consistency with investment in EV networks and their use in off-peak periods; and (c) avoiding some of the concerns related to energy poverty. However, there are a number of possible concerns.

- *Poverty:* If poorer consumers need more electricity at times of system peak, this system would penalize them. On the other hand, it would benefit the poor who do not consume much electricity or consume it off-peak. As mentioned above, energy poverty is a policy issue that is best addressed by providing direct subsidies to the poorest consumers, rather than distorting the price signals, and through better insulation and the installation of more efficient equipment, such as heat pumps. However, to reiterate, it is important to protect the most vulnerable.
- *Cost recovery at risk:* Fixed cost recovery is at risk since success in reducing congestion will lower revenues. This problem applies to both models and is not a reason to discourage efficient use and development of the network.
- *Complexity and negative consumer reactions:* The system may be too complex, with household consumers not understanding its implications or, more importantly, reacting negatively when electricity bills jump to reflect seasonal peaks. Most consumers are familiar and comfortable with peak pricing, for instance for air travel, but not for electricity. This can be addressed through education, but will take time. Retail companies and aggregators may also offer bundled prices that smooth the variations in network tariffs and include an additional margin to reflect the risk.

- *Discourage electrification (heat pumps):* Although this model would support the development of EV networks and off-peak use of EVs, it would raise the price of electricity used in red periods, including by electric heat pumps, and this could slow decarbonization through electrification. On the other hand, the variable charging approach reduces fixed payments and clients will save on energy costs during green periods, which should encourage demand shifting and the use of batteries. Indeed, this network pricing structure would provide commercial opportunities for the retail company or aggregator to develop storage facilities.
- *Does not reflect real-time conditions:* Endesa's initial proposal does not reflect real-time congestion, so is not as efficient as it could be. A more 'dynamic' variation of this model, also proposed by Endesa, would allow network charges to be set closer to real-time and to more closely reflect congestion on the system. Although that would increase price volatility and might elicit negative consumer reactions to changes in price, the dynamic model could be introduced later, when consumers and intermediaries are accustomed to the idea of varying prices.

These models each have strengths and weaknesses. Both can send price signals to encourage investment in EV network charging networks and favour utilization in off-peak hours. Both need to address concerns related to energy poverty and recovery of fixed costs. However, there are two important differences. First, the fixed charging approach aims primarily to kick-start electrification, especially investment in electrical equipment – notably electric heat pumps that provide heat and cooling – that consume in peak and off-peak periods[6]. The logic is that early electrification will bring with it energy efficiency (since EVs and heat pumps have very high energy efficiency) and decarbonization (since electricity is generated by renewable sources) and that high variable access charges will discourage certain kinds of electrification.

Second, the variable charging model charges on the basis of actual use of the network, whereas the fixed charging model does not. In that respect, the variable charging model sends better signals to use the network efficiently, reduce congestion and lower network investment costs. Furthermore, these economic signals will be even sharper if access prices more closely reflect actual congestion. This will matter increasingly as BTM activity becomes more relevant and makes congestion less predictable. Large consumers will have the incentives and the ability to manage this volatility and invest accordingly. The variable approach may discourage early consumer investment in heat pumps and other electrical equipment that consume in peak periods. However, fixed payments are lower and consumers or their intermediaries could install local storage to enable purchasing electricity in off-peak periods for use or resale in peak periods. Furthermore, this approach would encourage the development of electrical equipment designed to operate when costs are lower. Although there is a risk of discouraging consumers from early investment in heat pumps, the variable charging approach promotes efficient use of the network and of distributed energy resources, and should provide efficient incentives for investment in the network and in flexible demand options. Looking down the road, these efficiency incentives will become increasingly important.

5. Establishing local congestion markets

With the growth of distributed energy resources, the distribution system operator (DSO)[7] will need to manage the uncertainty about the volume, timing and direction of flows on the network. New mechanisms are needed to manage the network, both in the short term and when making investment decisions. Market mechanisms are an obvious tool, and BTM resources should have incentives to participate in those markets since consumers and aggregators can provide flexibility to help manage

[6] If there are fiscal distortions that favor other technologies, for instance gas or gasoil boilers, the incentives for electrification will depend on these distortions.
[7] The DSO is the operating manager (sometimes the owner) of energy distribution networks, operating at low, medium and, in some member states, high voltage levels.

congestion. This section focuses on the creation of new markets for local congestion management services.

Nodal pricing

One way to manage congestion would be to introduce nodal pricing, setting market-based electricity prices for each node on the system. Prices would differ by an amount that reflected the congestion costs between the nodes. In this way, nodes with high prices would elicit greater supply and reduced demand; and low-priced nodes would have the opposite effect. Although this model is theoretically attractive, and used in some countries, it has two main drawbacks that are especially relevant at a local level.

- *Technical complexity*: Nodal prices can be technically very complex. As opposed to transmission, which has only a few hundred nodes, distribution has several thousand nodes. The costs and complexity of introducing nodal pricing at distribution level can thus outweigh the potential benefit.
- *Political sensitivity:* Nodal pricing runs into difficulties in countries where regional differences in prices are politically sensitive.

Local flexibility markets

Introducing local flexibility markets is an interesting option. These markets would need to reflect different levels of congestion and the applicable timeframes for reducing it. Drawing once again on the traffic-light analogy, below is a proposal by the Spanish market operator (OMIE) in conjunction with IDAE, the Spanish Institute for Energy Diversification and Savings.

Green-light conditions exist when there is no congestion on the distribution system. These are fundamentally the same conditions that apply under the green-light access tariffs that were discussed in the last section. In this case, there is no need for a local congestion market and consumers may participate directly in wholesale markets. Since the growth of distributed generation will reduce the volume of electricity flowing into the distribution network, most hours will be free of congestion.

Yellow-light conditions reflect temporary congestion, for example anticipated next Tuesday at 6 pm in a specific location on the distribution grid. To relieve that congestion, the DSO would request a market operator (which potentially could be controlled by the DSO) to acquire the necessary flexibility service, for instance through a reverse auction that determines the price and selects the suppliers, including BTM providers or their representatives.

Red-light conditions reflect structural congestion that requires investment, either by the distribution company or by alternative providers, such as aggregators with access to a range of BTM and other resources. In these conditions, the DSO would request a market operator to select the provider and determine the price for the service. Since overcoming structural congestion is likely to require investment or allocating resources to an asset that will have to be available when needed, the selected provider would receive a fixed availability payment for the commitment to provide flexibility, when needed, as well as the variable market price in the flexibility market when the service is called.

The attraction of this proposal is that it creates local flexibility markets where none now exist. It offers the basis for establishing a price to support efficient investment and operating decisions behind the meter, whether managed by the consumer or aggregators. However, as always, the devil is in the details, especially the identity of the market operator and the incentives for the DSO. The DSO should only control the market operator if regulation or ownership separation can overcome two conflicts of interest. One is between the DSO and the owner of the distribution network. The other, even more complicated, is between the DSO and the market participants – retail and aggregator – belonging to the same vertically integrated group of companies. An existing market operator is another obvious candidate to run these markets, with the advantages of standardization and synergies with access to existing Day-ahead and Intraday markets. It is also possible to envisage a variety of new local market operators.

To improve the incentives for the distribution company, the regulator could introduce a financial inducement to lower the distribution company's costs of meeting its performance targets related to congestion. For instance, as in the UK, the regulator could allow the distribution company to keep a proportion of the savings associated with choosing an alternative – such as flexibility from distributed energy resources – instead of investing in its own network.

6. Opening access for BTM participation in all markets

Today there are many different wholesale electricity markets, including financial and physical markets trading over many time dimensions. Although existing wholesale markets were designed with large-scale generation in mind, they have evolved to facilitate the participation of smaller producers and large consumers, normally through aggregation companies. However, ancillary services and balancing markets in many countries have been effectively off limits to prosumers or aggregators wishing to sell energy and flexibility. In these markets, a limited number of generators set prices that are passed through to consumers. It is precisely in these markets where demand-side flexibility has an opportunity to compete for relatively attractive margins.

To address these challenges, the proposed reform of markets involves at least three changes.

- *Authorization:* The first reform is to authorize consumers, prosumers and aggregators to participate in all existing markets, subject to meeting certain conditions.
- *Redefine the conditions for participation in markets:* The second and more important reform is to redefine the conditions for participating in these markets so that the door is genuinely open for demand-side participation, including all BTM resources. For instance, current regulations for the balancing market in Spain require suppliers to have at least 10 MW of capacity. Although aggregators could presumably meet that condition, information communication technology is able to cope with suppliers with significantly less capacity. At the time of writing, the Spanish regulator is proposing to reduce the required capacity to 1 MW in line with European platforms. The system operator may have a natural preference to maintain existing protocols and be able to insist on risks to supply security (resource adequacy) or system stability. However, it should be given strong incentives to promote competition in the provision of balancing and other services. These incentives are the best guarantee that BTM assets will be able to participate in existing and new markets.
- *Establish new markets and services:* A decentralized and decarbonized system will require new kinds of flexibility, in multiple time dimensions. These may include long-term capacity markets and local markets, as well as markets to deal with the loss of inertia – resulting from closure of large power stations – and to respond to fluctuations in output related to intermittent renewables. The regulator should be identifying the new system needs, and provide incentives for the market operators and the system operators to establish new services and markets in which BTM participation is welcomed on a non-discriminatory basis.

7. Rethinking wholesale market design for a decarbonized system

Current energy-only electricity markets are broken and the system relies increasingly on governments to determine the mix, location and quantities of energy resources. There are many proposed reforms, but most aim to solve only one of the problems of energy-only markets, for instance adding capacity markets to overcome the problem of 'missing money'. This section focuses exclusively on the 'two-market' approach, which attempts to address all of the problems faced by today's energy-only markets (Keay and Robinson, 2017b). That approach places consumer decisions at its core.

The two-market approach creates separate markets for two different sorts of power ('on demand' and 'as available') at both producer and consumer ends. For producers, dispatchable plants would operate in the on-demand market, be dispatched according to merit order when needed, and paid as at present in the energy-only model. Intermittent renewable plants would participate in the as-available market; in principle, they would operate when available and, at least initially, be paid a price reflecting the levelized cost of electricity, similar to current auction arrangements in a number of EU countries. The idea is that the differing costs and operation of sources in the two wholesale markets would be reflected in the retail market. Consumers would be able to buy from either of the two markets at retail prices reflecting their respective wholesale prices, or buy combinations of the two sources of power. Initially – as at present – it is likely that price support would be needed either at producer or consumer level to make the as-available (renewable) offer attractive to consumers, but, over time, as carbon prices increase and renewable costs fall, the support could be removed, creating a potential exit strategy for government subsidies and control over investment decisions.

The benefits of this model are discussed in detail in Keay and Robinson (2017b). The model is particularly relevant for the development of BTM activity for at least five reasons.

- *An efficient alternative to own generation:* Consumers facing the option of investing in rooftop solar will have an alternative, namely to purchase renewable energy produced on the system at a stable and attractive price. The model is designed to incentivize consumption when the contracted renewable power is operating. In this way, the consumer is helping to integrate intermittent renewables into the system and reducing the need for the system to rely on generation from fossil fuels. This also eliminates or at least reduces the incentives for uneconomic bypass that were discussed in Section 3 of this paper.
- *Incentives for consumers to maximize their use of as-available (renewable) power*: Consumers would now have an understandable and effective choice, along with price incentives, to use renewable power from the system. Markets for demand response, on-site storage, distributed generation and the supply chain that supports these and other services, would develop in response to their preferences.
- *Meaningful price signals for consumers to contribute to overall system optimization*: In effect, security would be privatized and consumers would be able to decide for themselves how far they were prepared to pay for secure supplies. (System stability is a separate matter and would still be subject to system operator control.) It would be possible for consumers to use their own Value of Lost Load assessments in deciding whether to access the on-demand market. The same ideas could be adapted to enable consumers to reveal their preferences with respect to distributed resources and network access.
- *A long-term contract for selling energy that is excess to needs:* Consumers could contract to sell renewable energy into the as-available market at a long-term price that reflects the long-term costs reflected in that market. This could be a local market or part of the wholesale market.
- *An incentive to develop and sell flexibility:* Consumers will have an incentive to manage their own BTM distributed energy resources, e.g. batteries and electric appliances, in order to sell flexible energy services into the on-demand market.

This proposal aims to reveal consumer preferences and support the development of a supply chain that would respond to those preferences. It should be viewed as a long-term vision, rather than a model to be introduced immediately. If the two-market approach is accepted as a possible goal, there are many steps that could be taken that would lead in that direction, without necessarily ending up in the precise model that is described above. For instance, it would be possible initially to focus on the two markets at the consumer retail end, while maintaining a single wholesale market, or integrating the two wholesale markets[8]. The aim would be to experiment, in a 'regulatory sandbox', with tariffs, markets and regulations that give consumers the opportunity to choose between the two different kinds of energy and thereby to learn about consumer preferences.

[8] See Grubb and Drummond (2018), pp. 52–3.

8. Conclusion

Distributed energy resources located behind the meter should ideally benefit society as well the individuals owning them. For this to happen, it is critical to send efficient economic signals. This paper has analysed a number of existing economic signals that encourage inefficient investment and operating decisions behind the meter in some liberalized markets of the EU. These decisions could raise the costs of decarbonization and slow the energy transition, and shift costs to poorer consumers and future generations. For each of the identified problems, the paper makes recommendations, which are summarized below.

- *Fiscal reform:* First, fiscal reform is needed to eliminate incentives to generate (and store) one's own electricity simply to avoid paying taxes and levies collected through regulated electricity tariffs. These levies fund public policies, notably the promotion of renewable power and cogeneration. Failure to reform fiscal policy will encourage uneconomic bypass of the electricity system, raise system costs, enable the wealthy to benefit, leave others to bear the fiscal burden and slow electrification, which is recognized as being key to decarbonization and improved energy efficiency. Eventually, governments will need to eliminate this fiscal distortion. It would be far better to fix the problem now, rather than later when it will be politically even more difficult. The paper makes a number of recommendations, with the main proposal being to finance support for renewable energy and other public goods through the government budget, not through special charges on electricity.
- *Access tariffs design:* Second, regulators should design access tariffs to provide incentives to invest in, and operate, distributed energy resources that lower the overall costs of the system as well as benefiting the owners of the resources. The paper compares and contrasts two extreme approaches: one recovers virtually all costs through fixed charges (per kW contracted) and the other through variable charges (per kWh consumed). Both are workable. The paper concludes that the fixed charge approach is designed primarily to kick-start consumer investment in electrification, especially when there are no fiscal distortions favouring other technologies, whereas the variable charges approach is designed to encourage efficient investment and use of distribution networks and of distributed energy resources. In future, these efficiency incentives will become increasingly important.
- *Market reform:* Third, governments and regulators should ensure that consumers and their representatives can participate effectively in markets for energy and flexibility services. All existing wholesale markets should be opened to consumers, especially the flexibility markets where margins are typically higher. Furthermore, establishing local congestion markets is an important first step to managing local distribution networks. These local markets should be designed explicitly to encourage participation of distributed energy resources and to protect against conflicts of interest involving the distribution company. As a long-term goal, the proposed two-market approach provides the basis for revealing consumer preferences and for supporting the development of a supply chain that would respond to those preferences.
- *Reforming entire electricity systems:* Fourth, policy makers should recognize the need to think about reforming entire electricity systems, rather than reforming its separate parts. This is why the paper emphasizes efficient economic signals throughout the system. This is also why the paper recommends system-wide market reform, through the two-market model, rather than partial reforms that address only some of the problems of energy-only markets.

Fundamental changes are under way in the electricity sector. The primary responsibility of governments is to provide a framework of markets, regulations and fiscal policies that send efficient economic signals to all agents in the system. That framework should be designed to reflect consumer preferences rather than the preferences of central decision-makers and to enable consumers to drive the energy transition process. It should also be designed and introduced in a way that consumers understand and embrace since their support is critical to a successful energy transition.

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