Paying for Transitions

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Paying for transitions: The allocation of 'whole system' energy costs and implications for the study of sustainability transitions

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Abstract

This paper will seek to address the following question: How are whole system costs allocated in the electricity transition? New technologies require existing infrastructure to be reconfigured and this imposes additional whole system costs which need to be collectivised and allocated across system users in some way. The paper is a discussion piece written with a view to investigating whole system cost allocation through empirical research, for example, into how levels and types of electricity capacity are decided upon, and how costs are recovered and allocated through different types of charging methodologies and tariffs. The costs of reconfiguration are analysed and discussed at the national and subnational levels through the lens of allocation regimes; the rules governing how the economic costs and risks involved in electricity supply are spread amongst system users. Ultimately, the aim is to scrutinise who pays for energy transitions.

1 Introduction

New technologies require existing infrastructure to be reconfigured and this imposes additional *whole system* costs which need to be collectivised and allocated across system users in some way. In the energy sector, deep decarbonisation implies a move away from traditional system configurations which were build up around highly centralised and largely thermal-based forms of generation, an implication of this will likely be a requirement to increase the overall *capacity* across electricity systems. This is in order to cope with increasing electrification of demands (including transport and heating) and the greater complexity and variety of power flows that will result from high levels of variable renewable energies (wind and solar) and increasing amounts of distributed energy resources. This paper will seek to address the following question: Who will pay for this additional capacity and through what political processes are whole system costs allocated in the electricity transition?

While economists set out to design markets and regulatory frameworks which allocate costs to responsible parties through 'cost reflective' charging, the research gap this study proposes to fill is the analysis of who makes decisions about cost allocation and on what basis. The paper is a discussion piece written as an initial exploration of the topic through a transitions studies lens. This is with a view to investigating whole system cost allocation through empirical research, for example, into how levels and types of electricity capacity are decided upon, and how costs are recovered and allocated through different types of charging methodologies and tariffs. Ultimately, the aim is to scrutinise who pays for energy transitions.

Two types of whole system costs are analysed in the paper: *Network* capacity, on both the transmission and distribution grids, and the excess generation capacity which can be dispatched for system *balancing*. As the electricity system needs to be kept in balance second-by-second and the scope for storing electrical energy is currently limited, the amount of capacity required to meet demands and maintain reliability at any one point in time is difficult to predict in advance and, due to the risk of systemic failure, the cost of failing to do so are difficult to calculate. Also, demand-side response to short-term price signals is limited in the electricity sector and as a result the operation of the market as a form of cost allocation is severely curtailed; system reliability is one of a number of *market failures* which characterise electricity markets (Stoft, 2002). As a result, in both of these areas – networks and balancing – the costs of capacity are spread across the system amongst those connected to the networks.

Innovation studies and sustainability transitions researchers have discussed the implications of decentralisation and different forms of end-user participation for electricity system configurations, but this has mainly been from the entry point of the *smart grid* debate (e.g. Verbong et al., 2013, Erlinghagen and Markard, 2012). Here, it is claimed that with the aid of real-time pricing and smart metering the lack of demand-side response in electricity markets can be overcome and innovative ways of providing capacity and balancing which do not rely on capital intensive and centralised solutions can be found (Fox-Penner, 2010). While this *may* be possible in the medium and long term – although there are sceptical views on the promise of smart metering and grids (e.g. Thomas, 2012) – the reality of electricity system reconfiguration today is that centralised actors – mainly governments, network regulators and system operators – are the key decision makers when it comes to levels of capacity required and how system costs are allocated between different types of generators and customers. Therefore, rather than focusing on processes of technological innovation and the possibilities around smart grids, the paper instead focuses on the economic aspects of whole system costs and reconfiguration processes in today's systems.

In the remainder of the paper the costs of reconfiguration are analysed and discussed through the lens of *allocation regimes*; i.e. the rules governing how the economic costs and risks involved in electricity supply are spread amongst system users. In the next section we discuss how such regimes operate and have evolved in the context of liberalised electricity markets. Following this we discuss possible empirical strategies for investigating whole system reconfiguration based on an analysis of allocation regimes at the national level, by unpacking and comparing allocation regimes, and at specific locations on the grid where demand for the integration of low-carbon technologies is high but grid capacity is weak, thus opening up the potential for disruption of established regimes. In the discussion section of the paper we reflect on the approach in the context of research in the innovation and sustainability transitions field. We discuss how a whole systems view can open up new lines of questioning about the dynamics of transitions, particularly around the need to scrutinise who benefits from and who pays for energy transitions.

2 Allocation regimes in liberalised electricity markets

At a very basic level, the way electricity is paid for can be subdivided into two types of *allocation regime*, as illustrated in Figure 1 below. The first is termed a *marginal pricing regime*. Here, prices determined through the interaction of supply and demand for electricity determine how much energy is generated at any one point in time. Markets for electricity have been designed around marginal cost pricing principles where consumers choose the most competitive suppliers, who in turn procure electricity from providers in the wholesale market. As prices closely approximate the marginal costs of production, the idealised outcome is that the most competitive mix of power plants required to meet demand over a specified timeframe is selected – usually each 30 min – and that these marginal prices send long-term signals to investors about which plants are competitive and to invest in. This market doesn't operate autonomously of course, wholesale and retail markets for electricity were effectively designed and put in place as a result of political initiative and are highly structured, rules-based markets.

On the other side of the diagram is the *cost recovery regime*. Electricity, like other large technological systems, such as water and railways, is a networked industry. Network externalities and scale effects mean that the bigger the network gets and the more users connected, paradoxically, the cheaper it becomes to operate per unit of output (Künneke, 1999). In these cases, once the systems are place, they are cheap to operate and maintain, that is relative to the costs of building the network in the first place. Fixed costs will therefore not be fully remunerated via short-term marginal-cost pricing, hence the need for an alternative form of cost recovery via a centralised mechanism which spreads them out over many years (average cost pricing).

For the case of electricity supply there is an additional problem, the need for excess capacity to meet uncertain demands. Demand for electricity at any one point in time is extremely difficult to predict, this is partly due to the inability of existing metering infrastructure to send real-time price signals to customers, but also the fact that electricity has so many uses and is driven by a wide range of economic and societal factors. This demand-side uncertainty is problematic for system planners across all networked industry but is accentuated for electricity because of the need for second-by-second system balancing and the risk of cascading failures. In order to cope with fluctuations and deal with this uncertainty, excess capacity needs to be built into the system, in the form of additional power plants and power lines. This additional layer of security involves significant capital intensive investment; it is a *public good* which benefits all users of the system, therefore the costs cannot be allocated to individual users using short-term price signals.

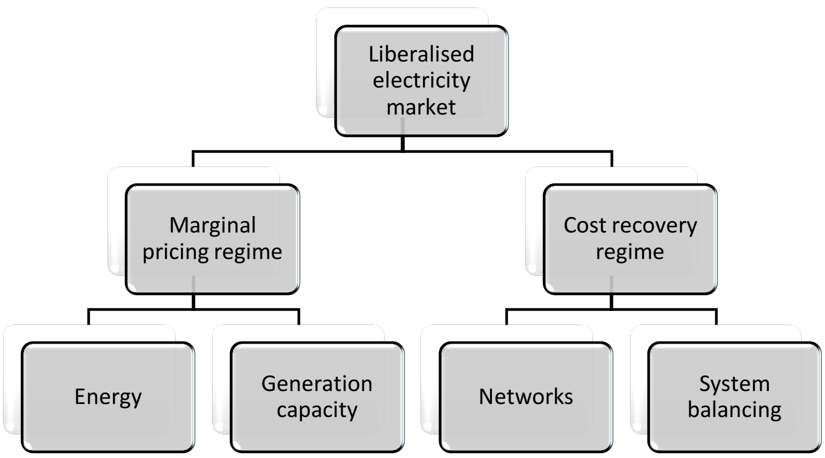

Figure 1: Idealised demarcation of allocation regimes in a liberalised electricity market

This description of the liberalised electricity model is a highly stylised and simplified account. It is by no means settled how an electricity market should work in practice; for example, there has been an ongoing dispute within the energy economics community about whether investment in generation capacity can happen on the basis of wholesale price signals (Keppler, 2017), and the appropriate level of integration across the different functional components of an electricity system, in particular whether generation, transmission and system balancing should be unbundled and treated as separate markets, or whether a high level of integration across them is closer to the optimal (Wilson, 2002, Cramton, 2017). It should also be noted that the implementation of electricity liberalisation has been a highly contentious and politicised issue in many countries and by no means a universally accepted model (Thomas, 2006).

A key development, and one strongly related to low-carbon transition, has been a general shift in emphasis in electricity markets away from marginal pricing towards cost recovery mechanisms as a means of valuing generation capacity. This has been mainly driven by the introduction of feed-in tariffs for renewables which, depending on their design, involve a transfer of risks related to operating in the market from investors to consumers. Another development has been the introduction of capacity remuneration mechanisms in many national markets as a means of delivering a safe capacity margin on the system which, some claim, is undeliverable in the 'energy-only' market due to high levels of price volatility.

This general shift towards more centralised forms of cost allocation in electricity systems has become a key topic in the energy economics literature (Pérez-Arriaga et al., 2016, IEA, 2016). Roques and Finon, for example, characterise the new dynamic as a *hybrid market regime* and provide a very useful structural overview of changes to key European power markets (Roques and Finon, 2017). Some have argued that the move to a cost recovery model for generation is an irreversible trend, the logic being that as fossil fuels – whose costs have traditionally been the key factor in price formation at the margin – are driven out of the system the key source of value in the market will be capacity rather than energy (Helm, 2017). Over time this segment of the market may begin to resemble the regulated natural monopoly areas where costs are spread out over many decades and allocated centrally. Economists in subfields such as institutional and industrial economics, auction theory and regulatory economics are broadly concerned with how to elicit information about the underlying costs in these areas of the system where conventional market approaches do not operate, and with how these costs are allocated amongst different users in a way which minimises them. What has been less discussed in this literature, and a fertile area for transitions researchers, have been the contextual factors which influence how allocation regimes are designed and *who* pays. As is discussed later in the paper, this is by no means uniform across countries.

3 Key components of *whole system* costs

Before turning to how transitions studies researchers might engage with such questions, in this section we discuss in more detail the network and balancing areas of the system, focusing on the mechanisms through which the costs are allocated. First we discuss network capacity costs, followed by balancing.

3.1 Network charging

Capacity on the transmission and distribution networks is limited and hence a scarce resource. As discussed above, charging for network services is challenging because of demand-side information asymmetries and the fact that a reliable network has public good characteristics. Decisions do need to be made however about who pays for the cost of providing network capacity. Broadly, charges for network services are determined by answering the following questions (further elaborated in the table below): *What* the charges are for? *Who* pays? Do charges vary depending on *when* generation or consumption occurs and *where* network users are located.

What?	• Are charges based on the use of *energy* (kWh), or a *capacity* (KW) measure based on power consumption during peak periods, or some combination of the two?
Who?	• How are costs spread across generators and consumers? • How are different types of consumer treated? (industrial, domestic etc.) • Are there exemptions for some network users?
When?	• Do charges differ to reflect fluctuating supply and demand conditions?
Where?	• Are costs spread evenly across the system or are localized capacity constraints considered?

Table 1: Design parameters for network tariffs. Based on (Grubb and Drummond, 2018)

3.2 Balancing the system

A second area of whole system costs relevant to the discussion is related to balancing the electricity system. As discussed previously, due to uncertainty and technical constraints, it has never been clear to system operators what demand levels might be during a scarcity period. The *value of lost load* for most customers – the price at which they might be willing to agree to be disconnected – cannot be found through markets as system operators (SOs) are risk averse and will intervene quickly if there is an imbalance. Dealing with this uncertainty requires some form of central intervention to dispatch capacity to balance the system and, because this is done at some remove from market trading, the costs have to be recovered retrospectively (Bolton et al., 2016).

On the exchange-based power markets which have been implemented in many European countries costs arise through the process of balancing the system, a brief explanation is as follows: After a point known as 'gate closure' the operation of the free market is progressively curtailed until, very close to real-time delivery, market trading concludes and instructions are sent to capacity providers to provide different types of services required to maintain the stability of the system. In the British market there are two forms of cost during this period[1].

1. The first is during a trading period known as the *balancing mechanism*; essentially a centrally coordinated energy balancing market. Here buyers and sellers submit bids and offers into the market to adjust their positions and ensure they are in balance. National Grid, the SO, also participates in this market and, based on the costs of doing this, it calculates *imbalance prices* which are imposed on those generators and

[1] See slide 5: https://www.ofgem.gov.uk/ofgem-publications/41372/electricity-cash-out-pdf (accessed 9.5.18)

suppliers who deviated from the positions that were communicated to the SO at gate closure.

2. The second cost is related to the 'out-of-market' short-term measures by the SO which are deemed necessary to balance the system in real-time. In Britain there has been four main categories of products which are procured by the SO: *Response* and *reserves* to deal with frequency and system balancing issues from seconds to 20+ minutes, *voltage control*, primarily local network issues, and other *ancillary services* required for system security. Under these main categories there will be a number of specific contracts for which the SO puts out tenders[2].

In some countries, like Britain, these balancing costs are essentially socialised. Recovery of both of these costs is through Balancing Services Use of System (BSUoS) charges which "is recovered from both generation and demand in equal proportion, by the Balancing Services Use of System (BSUoS) Tariff, calculated daily as a flat tariff (per MWh) across all users" (Grubb and Drummond, 2018). In other markets, such as Germany, balancing costs are not allocated separately but as part of the transmission network charge. This means there will be geographic variation in balancing costs depending on which of the four German transmission grids a customer is connected to.

4 The politics of whole system costs

It is generally recognised that there is no concrete law or set of laws in economics for how to recover these whole system costs (Pollitt, 2018, Grubb and Drummond, 2018). A general principle applied by energy economists is *cost reflectivity*; essentially to calculate and recover costs based on how they are imposed on the system at particular times and particular locations by different network users. However, as Pollitt notes, economics only provides general principles which, although delivering efficient outcomes in the context of an overall system, will have disproportionate effects on some consumers, for example those who may be inflexible and unresponsive to price signals (Pollitt, 2018)[3]. How this tension between economic efficiency at the whole system level and the political implications of different allocation regimes in terms of distributional effects is negotiated is a key site of contestation in the design of cost recovery mechanisms.

4.1 Varieties of allocation regimes

Unsurprisingly, given the lack of strict guidance from economic theory regarding the recovery of fixed costs, there is significant variation across countries. This is illustrated well in the figure below from Hinz et al.'s study of network charges (Hinz et al., 2018). Here, each European country is positioned according to a number of categories, including the percentage of costs levied on generators as opposed to end users, the balance between energy/volumetric and capacity charges, whether transmission and distribution charges reflect the costs of operation specific regional grids or are evened out across the user base, and whether charges for initial grid connection are upfront and reflect the cost of adding new capacity (deep) or are spread out over time and levied as a usage charge (kWh).

[2] https://www.nationalgrid.com/uk/electricity/balancing-services/future-balancing-services (accessed 9.5.18)

[3] As marginal prices calculated based on time and/or location of consumption will not be sufficient to recover fixed costs some economists propose to allocate these costs based on the differences in price elasticity of demand of consumers (*Ramsey-Boiteux pricing*). Essentially, inelastic customers pay a higher proportion as they are less likely to change their consumption patterns on the basis of higher prices, therefore cost recovery has less of an impact on consumption and hence overall efficiency.

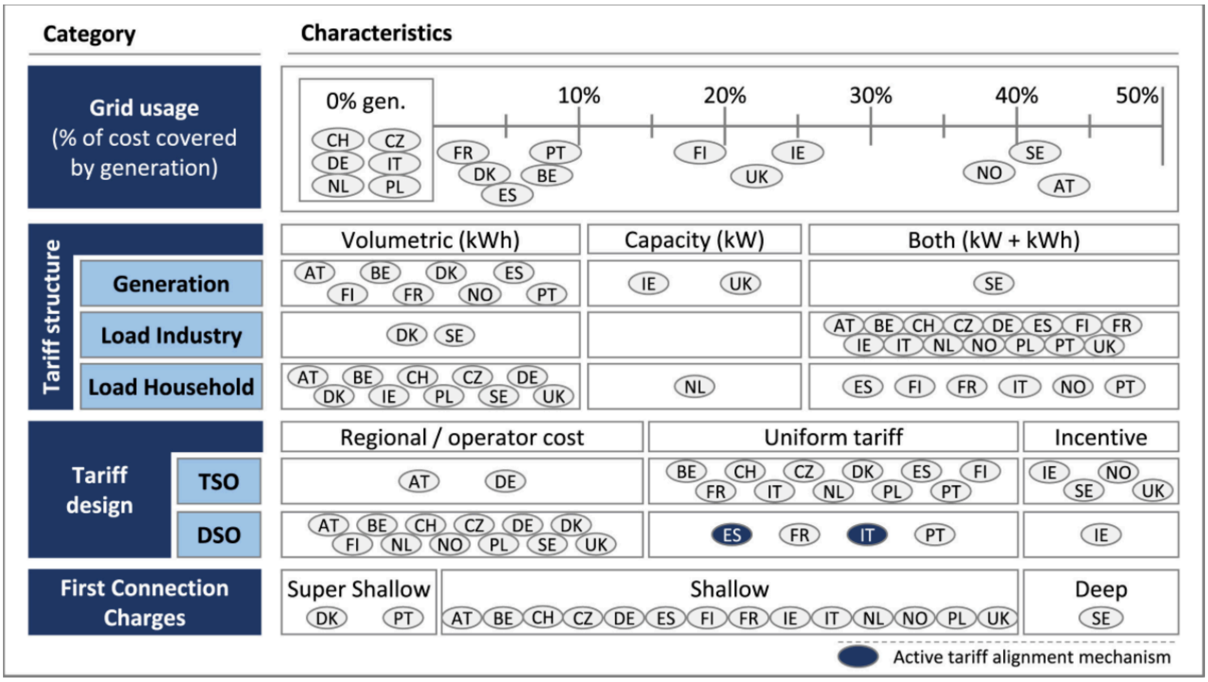

Figure: Approach to transmission charging in different European countries (Hinz et al., 2018)

Of course, energy economists are best equipped to make recommendations to regulators and policy makers about the likely material impacts of different cost recovery mechanisms, that is within the confines of analytical frameworks and categories developed by economists themselves, such as economic efficiency and societal welfare. The contribution of socio-technical systems research should be to pose more critical questions about choices and underlying political drivers; to account for why these national-level differences exist.

One potential avenue to explain variation at the national-level is to examine the political processes involved in designing and implementing specific policies and regulatory instruments. Recent work on the politics of sustainability transitions has highlighted the need to examine policy processes in much more empirical depth and to engage with a wider range of analytical lenses in the policy studies literature, including, amongst others, the *advocacy coalitions framework* and the *multiple streams approach* (Kern and Rogge, 2017). However, an important difference between the design of cost recovery regimes and the types of policy processes typically analysed in transitions research – niche protection policies to support demonstration and early stage deployment – is that decision making processes in relation to allocation regimes tend not to be overtly political and, despite their economic importance, often do not attract the same level of stakeholder attention as, for example, siting controversies for wind farms or decisions to reduce feed-in-tariff rates. Processes will tend to be more characterised by very specific and highly technical debates around the design of regulatory instruments and market devices.

In order to understand the distinctive character of these processes insights can be drawn from the literature on the history of technology in which experts and technocratic processes are central to the explanation of how large technological systems emerged and evolved in the 19th and 20th centuries (Hughes, 1983, Kaiser and Schot, 2014, Lagendijk, 2008). Technocratic processes, as charted by historians of European infrastructure (Högselius et al., 2015), were purposely designed by powerful system builders to remove politics from decision making processes and to deliberately ‘technify’ contentious issues. Disagreements were thus *solved* whilst keeping them within the confines of a shared technical language and culture. Engaging in and influencing such processes therefore typically involves high entry barriers, both in terms of expertise and institutional access; understanding and opening them up to critical investigation should be a contribution of socio-technical research into allocation regimes.

While the detailed analysis of how specific policies and regulatory instruments have been designed and introduced should be investigated as a source of variation, this does not account for the underlying structural processes which influence the design of allocation regimes and, ultimately, who pays. Investigating how, for example, different types of industry actors and groupings lobby government for favourable tariffs and exemptions would be an interesting extension of Hall and Soskice's *varieties of capitalism (VoC)* thesis (Hall and Soskice, 2001); that variations in national economic performance can be explained by complementarities between the interests of powerful public and private actors. Economic institutions across key spheres of economic activity – labour relations and corporate governance, inter-firm collaboration and competition, training and education – are shaped by these complementarities and differ markedly between liberal market economies (LMEs) - US, Australia and UK - and coordinated market economies (CMEs) - Germany and France. Economic outcomes in LMEs tend to be as a result of competitive processes, with government involvement taking the form of competition policy and independent economic regulation, whereas in CMEs outcomes are achieved more through negotiation and collaborative governance, with government as a more active participant and partner of corporate actors and labour unions.

A brief analysis of how large industrial consumers are charged for network services indicates that the theory may have some relevance to the analysis of why national regimes differ. The box below summarises the level to which different categories of industrial customers, categorised into bands 1A-1F[4], are charged for transmission networks in a number of European countries. Here we see different mixes based on charges for electricity use and capacity, and some also accounting for location on the transmission grid, as in the British case. In Germany the network and balancing costs are bundled together into a single charge, whereas in Britain they are separated, with balancing costs spread evenly across all users. There is a more even spread across customer bands in Britain, as oppose to Germany, and they are significantly lower for very high-usage customers in Italy and France. It may be the case that the relatively even spread of transmission costs across the different bands of industrial consumer in Britain can be explained by its historic commitment to competitive markets, often at the expense of industrial policy; whereas in the CMEs large, electricity intensive industries may hold a stronger bargaining position. In-depth qualitative analysis of the institutional history of the allocation regimes of these countries would be required to investigate the VoC thesis and whether the governance of natural monopolies can be added to Hall and Soskice's list of economic spheres which differentiate LMEs and CMEs.

[4] In the Eurostat database industrial customers are categorised into several consumption bands based on annual consumption (MWh): 1A<20; 20<1B<500; 500<1C<2,000; 2,000<1D<20,000; 20,000<1E<70,000; 70,000<1F<150,000 (Grubb & Drummond, 2018, table 1 p.14)

Overview of transmission costs faced by industrial customers in European countries. Based on (Grubb and Drummond, 2018)

Britain

- Costs recovered through Transmission Network Use of System charges (TNUoS)
- For larger customers with half hourly metering this is based on usage during the three periods of highest demand (known as 'Triads')
- Charges also depend on location with the application of a 'location-specific tariff'; 'from £29.58/ kW in Northern Scotland, to £51.96/kW in South- West England in 2017/18'

Germany

- Network and balancing costs are combined into a single tariff applied across the 4 networks which are regulated separately
- Charged on the basis of both *fixed* cost of capacity of connection and *variable* level of consumption
- Fixed charges increase as a proportion of total cost for high consuming customers (>2,500hrs of consumption)
- Bespoke tariff rates and discounts can be made available to customers with very high usage, over 10GWh. Max discounts can range from 80-90%, depending on level of usage.

France

- A single tariff for both transmission and balancing and no differentiation based on location.
- Tariff 'based principally on the consumer's voltage and capacity of connection, and time of consumption'
- This includes a fixed and variable charge and is calculated for customers at different voltage levels during 'pre-defined time periods'. Most customers can select from 'one of three tariff options, with different weighting to the fixed and variable components' whereas customers connected at higher voltage levels (350-500Kv) 'pay a fixed capacity charge and a single consumption rate, without time differentiation'
- Certain categories of industrial customers also qualify for 'tariff reductions based on their total consumption, pro le of use and electro-intensity'

Italy

- Separate tariffs for 'transmission and distribution, metering, and system services, all of which are applied equally across the country'
- Only customers connected at >380kV pay a fixed rate capacity charge and a variable usage charge is applied across all customers but disproportionately to lower voltage. High voltage customer pay approx. 90% less than those at medium voltage.

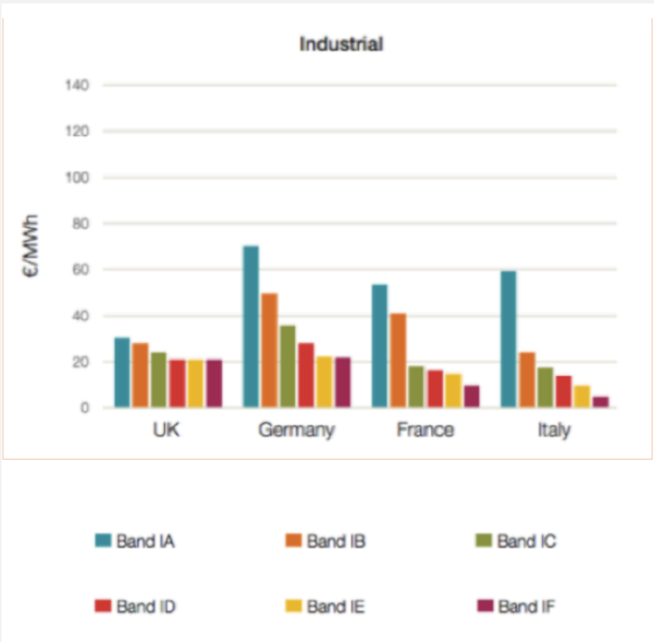

Figure 2: Comparison of transmission costs faced by industrial customers. Source: (Grubb and Drummond, 2018)

4.2 Disruption of national allocation regimes in transitions

National allocation regimes are struggling to cope with the integration of low-carbon technologies. As a result, new arenas of contestation are opening up where, in the absence of established procedures for the the integration of non-conventional technologies in parts of the system where capacity is weak, stakeholders negotiate whole system cost allocation in a more overtly political way.

National regimes have been designed with centralised generation technologies in mind. Taking into account the potential for unscheduled maintenance of nuclear and thermal pant and seasonal variations which affect hydro plants, the power output of these conventional sources of electricity generation have been relatively predictable, while their geographic distribution across the transmission grid could be planned, or at least predicted. As a result, the additional capacity required for system integration could be calculated with some certainty, enabling system planning.

However, for a number of reasons, the same level of certainty does not apply to low-carbon technologies, in particular variable renewables. Wind resource is often most abundant in geographical locations where the transmission grid is either not present or weak, while solar PV systems are being deployed on the lower voltage distribution grids or behind-the-meter at the building level. This, alongside the increasing electrification of transport and heating demand, is putting pressure on lower voltage grids where systems and cost allocation regimes have been designed for one-way flow of electrons.

As these issues are related to quite specific locations on the grid where capacity constraints are imposing high costs, it is typically at the local or regional levels where regimes are being challenged. Below we provide two very brief case studies to illustrate:

4.2.1 Transmission charges and wind energy in Scotland

The long running dispute in Scotland relates to the locational element of the transmission usage (TNUoS) charges explained earlier in the paper. Due to the low population in Northern Scotland transmission capacity is comparatively low, however, the region has the best wind resource in Europe and as a result there has been a long running dispute between Scottish stakeholders and the UK government about how the costs of the additional transmission capacity required might negatively impact the economics of wind in Scotland. This position is summarised in a 2011 statement by the Scottish Government:

> *"The grid network in Scotland needs to be able to deliver the connections that will transport and export the remarkable renewable energy potential in Scotland and its islands - with an estimated quarter of EU tidal and wind power and 10% of its wave power"*[5]

The core of the dispute was about equity and fairness, particularly in relation to how transmission costs are spread across the network user base. The main argument mobilised by the Scottish Government at the time was that the locational element in the transmission charge was unfair to Scottish generators which, they pointed out, "produce about 12% of

[5] http://www.gov.scot/Topics/Business-Industry/Energy/Infrastructure/TransmissionCharging (accessed on 9.5.18)

UK generation but account for 40% of the transmission costs, or about £100 million per year more than generators in the South" (*ibid*).

Scottish stakeholders called for a "national network charge" which would socialise costs across the UK. This became part of a number of issues under consideration as part of a UK House of Commons Energy and Climate Change Select Committee investigation into network costs, following which the UK Government summarised its position on the proposal in 2016:

> *"Electricity network charges vary by region and reflect the costs of running the network in that area and the number of consumers that those costs are spread over. The Government does not plan to move to national network charging, as the current cost reflective approach helps to ensure efficient use of the network and keeps overall costs down for bill payers across Great Britain. In contrast, national pricing risks an overall increase in network costs by weakening each network company's local accountability to its customers, as well as making charges less transparent"*[6]

The analysis behind the UK Government's position was conducted by the energy regulator, OFGEM, and published in 2015 (OFGEM, 2015). OFGEM examined charging across both electricity and gas, and at the transmission and distribution levels; according to their analysis, the current transmission charging approach actually favours consumers in this particular Scottish region:

> *"'typical' households on the single rate the electricity transmission component of their bills range from £21 per year in North Scotland to £37 in London and Southern England" (ibid)*

A stronger regional disparity emerged when electricity distribution charges were analysed, with households in the North of Scotland consuming more electricity, in part because many are not connected to the gas grid and hence having higher electricity usage for heating. For an average customer the combined annual transmission charges differ significantly in London and the North of Scotland: "from £107 (London) to £169 (North Scotland)". They also found that in the North of Scotland "electricity distribution charges are £47 above the Great Britain average but electricity transmission charges there are £11 lower than average" (p23).

OFGEM analysed the effects of moving to a national network charge, i.e. socialization of costs across the customer base, and stated the following:

> *"approximately 16 million households would face higher bills, while around 11 million would see reduced bills under such an approach. In most cases the increase or decrease would be small. In Scotland, 1.8 million households would face higher bills and 0.7 million households would see reductions…There does not appear to be any clear justification for national network charges in terms of regional concentration of vulnerability"*

This is an ongoing dispute with many dimensions and complexities but, as this brief excerpt illustrates, the polices are shaped by stakeholder interests and positions, but also by forms of technical appraisal which, in this case, were based on quite different framings of fairness and equity. For the Scottish Government the key priority was the impact on generation

[6] HC Deb 11 Apr 2016 PQ 32443. https://www.parliament.uk/written-questions-answers-statements/written-question/commons/2016-03-23/32443 (accessed on 9.5.18)

investment in the region and competitiveness in the GB power market, whereas for OFGEM the focus of the analysis was on costs to end consumers, this is unsurprising given that their legal duty as a regulator is to "protect the interests of current and future consumers".

4.2.2 PV behind-the-meter: production or consumption?

While the controversy about network charging in Scotland is primarily focused on the transmission level, the issue of the balance between generators and consumers and locational charging cuts across the networks. An issue which has become particularly controversial is the treatment of *prosumers* who invest in *behind-the-meter* (BTM) installations where generation and end-use become conflated. Here there are different views on whether self-generation should be categorised as production or consumption and how the excess electricity not consumed by the *prosumer* is valued in the market; should it be sold into the grid at wholesale prices (which would likely be very low), or netted off against future consumption, in effect valuing the electricity at the higher retail rate? If it is the latter this excess is categorized as a saving for the grid rather than an input, which leads to a potential misallocation of resources; PV may be producing excess during low demand periods meaning that highly valuable electricity at peak times is priced at too low a rate. Also, retail rates typically include whole system and policy costs, therefore providing what is in effect a subsidy which is paid for by the non-prosuming customers[7].

In Spain, for example, this issue came to the fore when in 2015[8] the Government introduced a new law which prohibited electricity export from consumers whose peak consumption is less than 100kW. The change in legislation also meant that consumption related charges - for network, policy and other system costs - would take into account a combination of output and input based on metering at the interface with the main grid, but the key point of controversy was that the metered self-generation - which is mostly consumed by the owner - would also be subject to these charges, and as such be primarily categorized as consumption rather than production (Aragonés et al., 2016). This led to a framing of the new tariff as a "sun tax"[9] . Its introduction is still disputed and the issue remains unresolved.

In relation to BTM generation it is worth also specifying the problems in relation to network charging. Although much of the consumption on an average basis will be met by the solar installation, there will be times when grid generation will be needed, and as a result a grid connection required. At the moment, for domestic customers, much of the distribution network tariffs in Europe are based on volume rather than capacity related charges (as described above), therefore the cost of providing this energy security benefit is only partially covered. The network capacity issue is relevant because a prosumer is still likely to need the same level of grid capacity which will be the maximum demand required during peak consumption hours. This issue is complex because up to a certain level of penetration BTM generation is actually beneficial to the grid as it reduces the need for centralised provision of voltage and frequency control.

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[7] The trade-off between *Prosumer* and societal benefits is summarised succinctly as follows: "Absent specific regulation, from the consumer viewpoint, the economic value of self-generation is the energy saving (€/kWh) that includes, in addition to energy costs, the policy charges and some network costs. However, from the societal viewpoint, the value of self-generation is rather the system avoided cost, that is, energy and network variable costs, but not the other system costs and policy charges" (Aragonés et al., 2016)

[8] Royal Decree (RD) 900/2015

[9] http://www.bbc.co.uk/news/business-24272061 (accessed 9.5.18)

This policy challenge of valuing BTM is well known and has been studied in significant depth from a techno-economic perspective (Green and Staffell, Pérez-Arriaga et al., 2016). What has been less studied is how such technical disputes are related to wider political contexts. A socio-technical analysis of the Spanish case could explore links to the 2008/9 financial crisis when the Government introduced significant cuts to renewable support policies. In Scotland the dispute is strongly related to the UK's devolution settlement in the area of energy and environmental policy. The Scottish Government has powers to set its own emissions reductions targets and, unlike the UK Government, has set specific targets for meeting demand in Scotland from renewable sources. However, powers, and hence responsibility, over electricity prices, markets, network regulation and levels of renewable subsidies are with the UK Government. The dispute about transmission charging is in some ways a proxy for this wider institutional alignment and the political tensions between these different governance levels.

5 Conclusions

The contribution of this paper has been to draw attention to the understudied issue of whole system costs which, because of the collective nature of electricity systems, technical constraints, and market imperfections, are difficult to assign to individual system users and are typically recovered centrally through regulated network tariffs. As low-carbon technologies move from protected niches to the mainstream and are integrated into systems, the issue of how the associated costs will be allocated will become increasingly salient. It has been argued here that socio-technical systems research should focus on how and why *allocation regimes* – the rules governing how the economic costs and risks involved in electricity supply are spread amongst system users – differ at the national level. It was also discussed how these regimes are being disrupted and potentially dismantled as new arenas of politicisation are opening up at specific parts of the grid where capacity is limited. This leads certain actors to question the underpinning principles of national regimes which have been built around conventional technologies and system configurations.

It will of course be beneficial for certain consumers and advocates of different technologies – both high and low carbon – to lobby for reduced tariffs or exemptions from system costs. A challenge for transitions researchers investigating such a highly politicised issue will be how to position the research. One option would be to appraise claims and counter claims about system costs whilst remaining neutral about societal impacts, similar to the symmetrical approach developed in the sociology of scientific knowledge (Bloor, 1976); another would be to develop some form of normative stance which, for example, favours certain types of low-carbon technologies, consumer groups, or which adopts the principles of social welfare as developed in the economics discipline. Another research challenge identified is the highly complex and technical nature of the debate around specific market and regulatory instruments which creates barriers to wider stakeholder participation. This may mean that these processes may not be amenable to conventional frameworks in political science and policy studies which have been discussed elsewhere as suitable for the analysis of energy transitions.

Finally, the organisers of this conference have rightly pointed out that an important, but now largely neglected, intellectual foundation of transitions studies was the study of complex systems as configurations of material and social elements which are deeply embedded in societies (Green et al., 1999, Rip and Kemp, 1998). This (re)turn to *whole* *systems* analysis is an important contribution to a field which has increasingly aligned itself with the study of technological innovation processes and policy design in that single domain. It has been shown here that who *should* pay for energy transitions is a surprisingly difficult question to answer, but a potentially fruitful one for the transitions studies field as it engages in a more substantive way with wider processes of system change.

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