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Managing Electricity Decarbonisation: learning from experience – the cases of the UK and Spain

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Section 1 – Introduction

For most of the 20th century, electricity was a relatively straightforward industry – a classic utility, with secure long-term assets, increasing demand and reliable revenues and consequently it faced few risks. The basic technologies changed little and technological trends were gradual and predictable – towards ever larger, more centralised and more efficient generation, and more extensive network development. Partly as a result, there was a steady decline in unit costs and steady demand growth as electricity's share of the energy market increased, apparently inexorably. The dominant model was of a regulated monopoly. Customers were regarded largely as passive consumers; the industry's task was simply to ensure that power was available at the flick of a switch.

Since about 1990, the industry, essentially unchanged for the previous hundred years, has undergone a rapid series of revolutions whose long-term effects are only just starting to emerge. The first shock was the introduction of liberalisation and competition, initially in a few pioneer countries like the UK and Norway, but eventually across the whole EU Single Market (and much of the rest of the world). This proved traumatic enough for the industry, but before its implications had been fully digested a new wave of disruption got under way, to a significant extent as a result of the imperative of decarbonisation. The industry now faces unprecedented technological, economic and institutional change – it is truly entering a 'new era'.

Perhaps most visible are the developments in electricity generation – the growing penetration of intermittent renewable plants, driven both by technological advances and by the policy commitment to decarbonisation. But significant shifts are also taking place elsewhere in the system with the rapid development of information and control technology, which is opening the way for new approaches to system management and more flexible demand. It is likely that we are only seeing the beginnings of these changes and they raise wider questions about the very nature of the industry's product and its relationship with its customers.

The technological developments have been accompanied by major policy and economic changes – falling electricity demand in developed markets, greater use of on-site generation leading to lower network income, governments rather than markets driving investment in both renewable and fossil generation, and so on. The institutional frameworks surrounding the industry are struggling to keep up. For two decades or so after 1990, governments across the world focused on liberalisation and the extension of market forces; now there is a new emphasis on decarbonisation, but governments have not yet worked out whether decarbonisation and liberalisation can go hand in hand or whether there is a fundamental conflict. Markets have also been slow to adapt to the new era – the industry has traditionally relied on short run marginal cost (srmc) or kilowatt-hour (kWh) pricing, although a large proportion of its costs have always been fixed (and some eminent economists like Ronald Coase have argued against the over-emphasis on marginal cost). With a growing penetration of zero marginal cost plants, the srmc approach looks increasingly outdated, whether at wholesale or retail level.

Regulation too needs to respond to the changes under way and the increasing decentralisation of the system. New coordination and control methods may be required to manage the rapid growth of intermittent generation, particularly wind, and of decentralised sources like solar photovoltaics. Indeed the whole basis of the industry's workings are coming into question – what ultimately are its products? How should it price them? What business models should the industry be developing? What are its resources and how do storage and demand response fit in? How should effective competition among all distributed and centralised energy resources be facilitated?

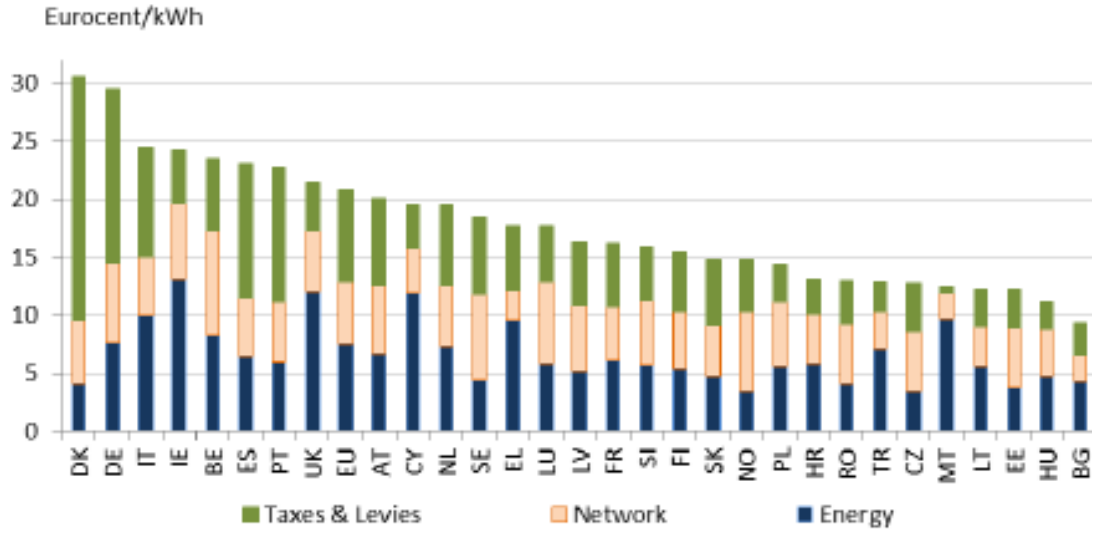
This paper looks at the ways in which two European countries – the UK and Spain – have been responding to these 'new era' challenges and what lessons can be drawn from their experiences. The choice of these two countries is based on a number of factors. They are not necessarily those which initially come to mind as being at the forefront of the decarbonisation revolution – many people would think first of, say, Denmark or Germany. Those countries have indeed made significant strides in changing their electricity systems in response to the new challenges. However, among other things,

this means that they have been more frequently studied and cited than the two countries which are the focus of this paper; their experiences are therefore likely to be relatively familiar.

Furthermore, in a number of respects Denmark and Germany could be regarded either as untypical, or as having faced the 'new era' challenges in a less acute form than the UK or Spain. For instance:

- Both are extensively interconnected with their neighbours and in many ways this has made the task of system balancing easier. Denmark, for instance, has access to the large hydro resources of other Nordic countries and can respond to the intermittency of wind power by importing or exporting electricity as needed, rather than having to achieve balance solely within its own system. Germany, similarly, has greatly expanded its electricity trade with neighbouring countries as its wind and solar generation have grown and enjoys access to the extensive hydro capacity in the Alps.
- In Germany, much of the impetus for the 'Energiewende' (energy transition) has come from the decision to phase out nuclear power after the Fukushima accident. There is wide public support for the move and wide acceptance of its consequences. Denmark has also achieved a broad policy consensus – in the words of the International Energy Agency (IEA), 'A long history of consensus-based policy making and political stability has been leveraged to develop Denmark's far-reaching and comprehensive energy policies'. (IEA 2011) So in both countries political circumstances are particularly open to the changes needed.
  One of the similarities is the relative decentralisation of the industry in both countries. Germany's experience, for instance, has been described as a 'decentralised energy revolution' (Burger and Weinmann 2014). Much of the renewables development has been undertaken by local, communal, and municipal organisations rather than by the major utilities. In Denmark, although large scale generation is dominated by two companies (Dong and Vattenfall), the small scale wind and combined heat and power sectors are much more diverse, as is supply. In 2009 for instance, there were 84 distribution companies for only 3.2 million consumers (IEA, 2011). So in these countries, consumers often feel more directly involved in the decarbonisation process than elsewhere.
- Perhaps as a result of the political and institutional circumstances outlined above, both countries' consumers also seem to accept relatively high electricity prices without major political controversy, although recently there has been some resistance from smaller consumers. According to Eurostat, they are the two highest price countries for household consumers in Europe – see Chart 1.

Chart 1: Electricity prices for households in Europe



Source: Energy prices and costs in Europe COM (2016) 769

By contrast:

- Both the UK and Spain feature in (and near the bottom of) the list of European countries below the EU's 10 per cent interconnection target1. Neither has ready access to the hydro capacity of its neighbours. To a large extent, both countries therefore have to solve the problems of intermittency at home.
- There is probably a lower level of consensus about the direction of travel in the UK and Spain. The UK has certainly achieved political agreement on the goal, in emissions terms, but many of the modalities, like nuclear and onshore wind, remain highly contentious. In Spain, other concerns – and in particular the economic problems the country has encountered since 2008 – have tended to take priority.
- In both countries, the electricity industry itself, and renewable generation in particular, tends to be dominated by larger players. For instance, Iberdrola, the Spanish company, is the largest wind developer in the UK and Spain, and indeed the world in general but has little involvement in the German or Danish markets. Indeed, in Spain, decentralised renewable generation has been discouraged.
- Prices and affordability have been topics of controversy in both countries, as discussed later in this paper.
- The UK was a pioneer in liberalisation and still remains committed to the principle of markets. On the other hand, it also has what are probably the world's most rigid and demanding emissions targets, enshrined in statute in the Climate Change Act 2008. Spain adopted a version of the UK's original liberalised electricity market in the late 1990's and has integrated renewables into the short-term operating regime successfully. However, the government has intervened heavily in investment decisions and regulation, creating a tariff deficit of over €25 billion that consumers will be paying for the next generation. Both face a difficult balancing act in developing their policies for electricity.

As a result of these, and other, factors, it could be argued that the UK and Spain in many ways face the 'new era' challenges in particularly acute form and that the way in which they have responded to these challenges is of significant wider interest – both for what they have done well and for the mistakes they have made.

In order to keep this paper to a manageable length, a choice had to be made about the number of topics which could be covered and the depth to which they could be investigated. The authors make no claim to have produced a definitive or final analysis; rather they have aimed to use the experience of the two countries to explore some of the issues raised by the 'new era' challenges in the hope that the countries' successes and failures may throw some light on possible ways forward.

In considering which aspects of the UK and Spanish response should be selected for examination, the main criteria have been:

- Range: the assessment below tries to cover a wide range of issues from the very highest level (institutions and governance) to the level of technical detail (for example treatment of embedded generation).
- Differences of approach: In order to see what lessons can be learned, the focus has been on areas where the two countries have adopted significantly different approaches. Where the same overall approach has been taken (for example as a result of EU harmonisation measures) there is less to be learned and so those issues are therefore not covered to any extent: the aim here is not to assess EU policy as such.

[1] Commission Communication *Achieving the 10% Interconnection Target* COM (2015) 82

- Relevance to other countries: The issues examined are those of wider relevance. Some issues of undoubted importance (for example nuclear power and coal) are only touched on in passing here, as each country has its own very specific problems in these areas.
- Links with decarbonisation policy: The issues examined here are directly linked with decarbonisation policy – there are many other issues of a regulatory nature which are not specifically related to decarbonisation, but these are not the focus of this study.

The paper is divided into the following sections, each of which is summarised below:

Section 2 – Institutions and Governance

Decarbonisation creates major challenges for the governance of liberalised markets. The basic aim of liberalisation was for governments to stand back from the management of the electricity sector and allow market forces to drive developments, including investment as well as operations and consumption. With the new priority of decarbonisation (addressing the 'greatest market failure the world has ever seen' – Stern 2006) this hands-off approach is no longer tenable in its purest form. Nonetheless intervention risks distortion and inefficiency – governments have been trying to develop arrangements which give the maximum scope for markets or regulated market mechanisms (like auctions) to operate while still ensuring the achievement of climate change objectives. In particular, the section looks at:

- Overall governance. The UK has been a pioneer in this area. Its Climate Change Act insulates the decarbonisation process from short-term political pressures and sets clear long-term goals. Spain has a less developed institutional framework and policy development has been more erratic. (Section 2.1)
- Progress with decarbonisation. Whether or not it is a direct result of the differences in governance, the UK is also performing very well against its climate targets. It has already achieved reductions of around 40 per cent against a 1990 base, a decade and a half ahead of the EU in general. It will face more difficult challenges in the future but the framework seems so far to have proved robust. Spain has thus far met its climate change targets, but these were much less demanding than those of the UK. (Section 2.2)
- Role of the regulator. Sector regulators originally had relatively defined economic functions. As decarbonisation rose to the top of the energy agenda, the UK started adding environmental responsibilities which threatened to overwhelm the regulator's core role. It now seems to be moving back to something more like its original role. In Spain, the regulator has always had more of an advisory role to the government and there has been less of an attempt to introduce environmental responsibilities. However, the downside is that the independence of the regulator has come into question. (Section 2.3)

Section 3 – Costs, prices and burden-sharing

Decarbonisation inevitably involves higher costs, at any rate initially. Decisions are needed on how costs should be contained, how far they should feed through to consumer prices, and how the cost burden should be shared. This section looks at:

- Cost containment. The UK has experimented with various forms of cost containment, including the use of auctions for (some) low carbon generation and an overall cap on the extra costs involved. Despite some problems, the approach has on the whole worked reasonably well, though it is coming under strain. Spain meanwhile has had less success, starting off with more open-ended support schemes whose costs were not fully passed on. This led to various abrupt efforts to contain costs and a halt in new investment. (Section 3.1)
- Price intervention. Spain has relied heavily on price intervention to minimise the effect on consumers, leading to a huge overhang in the form of the 'tariff deficit', a problem which has been contained in the sense that the deficit is no longer growing, but whose consequences continue to distort policies. The UK has generally resisted the temptation to regulate electricity prices directly;

the sporadic, and ill thought-through, UK government interventions in pricing structures have generally proved counter-productive and inimical to innovation. (Section 3.2)

- Government wedge. This refers to the extra costs in electricity supply due to government decisions rather than market forces. These can be hidden or transparent; can appear directly in electricity prices or be spread more widely. In the UK the extra costs are relatively transparent – they appear in the national accounts as 'tax and spend' – although they are not identified separately on consumer bills. In Spain the position is more complex but also more opaque: a large proportion of the final price (45-50 per cent) is accounted for by taxes, various levies and cross subsidies, not all of which are related to decarbonisation. (Section 3.3)

Section 4 – Network regulation

Transmission and distribution networks have always been regulated, because of their monopoly nature, but the task is complicated by the process of decarbonisation. It requires the integration of numbers of new sources at both transmission and distribution levels and poses new questions for the regulators – what changes are needed to facilitate the introduction of these new sources while at the same time avoiding creating distortions and inefficiencies? How can the move towards a decarbonised system be guided towards an optimal outcome, given the uncertainties about the nature of future systems? The section looks at three issues:

- Distribution. One of the areas where uncertainty is greatest is over the future role of distribution companies. In the past their role has been relatively passive, simply to distribute electricity generated from central sources. In the future their role will be much more active, but many scenarios are possible. The UK has tried to cope with the uncertainties by adopting a flexible and exploratory approach but one result is that it is only moving rather cautiously towards a more active role for the distribution companies. Spain again has seen little progress in this area. (Section 4.1)
- Interconnectors. As noted above, both the UK and Spain suffer from relatively limited interconnections and both want to increase the level of interconnection capacity. This should help promote competition, put downward pressure on prices, increase security and reduce the system costs of decarbonisation. In principle, such connections could be unregulated ('merchant') projects. However, in practice, to reduce risk, a 'semi-regulated' cap-and-floor system has been introduced for the UK, while Spain still maintains a monopoly for its national transmission company in this area (which has led to challenges from the Commission). One problem is that there is no supra-national or federal regulatory authority in Europe to regulate such links. (Section 4.2)
- Network pricing. There can be a difficult trade-off between ensuring that prices cover costs and encouraging the development of the new sources. The UK has gone for a relatively open-ended system which encourages innovation and focuses on outputs in order to create appropriate incentives for the networks. Spain has a less developed regulatory approach and retains a largely traditional form of rate of return regulation. (Section 4.1)

Section 5 – Promoting balanced investment

Because the environmental externalities involved have not been fully internalised in prices, special support is often needed to ensure that the right sort of investment takes place. However, hitherto the process has been somewhat erratic, with more focus on building, say, a certain amount of renewable generation, rather than considering the most effective way of getting to a low carbon system. The process has in turn created the need for new interventions, for example capacity markets. The section looks at systems of support for particular types of resource:

- Renewables. Both countries have changed their systems of renewables support over time. There is now more emphasis on competitive approaches and less prescriptiveness about technology types. Nonetheless, the focus is still largely on intermediate targets (share of renewables) rather

than the ultimate goal (an efficient low carbon system) and there have been unintended consequences. (Section 5.1)

- Distributed generation. It is generally agreed that distributed (embedded) generation will play a greater role in future systems because of a combination of technical developments and the need for decarbonisation. However, if governments try to force the process along by creating special incentives they risk creating new distortions. Both countries have seen over-generous support schemes which have had to be revised. In Spain the schemes focused on centralised generation and the government is very reluctant to support decentralised ones. The UK is currently considering whether distributed generation is being over-rewarded through the regulatory system more generally. (Section 5.2)
- Demand response. Again it is generally agreed that this will be an important feature of future systems and a number of experiments are under way. To date, however, tangible progress remains thin on the ground and it is unclear how to make best use of this resource. (Section 5.3)
- Capacity markets. One of the unintended consequences referred to above has been the failure to consider the impact of large amounts of intermittent plants on the system. Among other things it has made investment in reliable generation less attractive, leading to the creation of capacity markets. The UK is facing tight supply margins and has created a system-wide market, which has advantages in theory but has in practice not produced the results policy-makers were aiming for. Spain has a more administratively based approach; it has also faced problems but in view of the considerable over-capacity in Spain the problems there have been less acute. (Section 5.4)

Section 6 – Conclusions

Drawing on the discussion in the preceding sections, this section draws some broad conclusions:

- Governance. The UK's experience seems to vindicate the underlying principles of its governance system, specifically: to try to insulate climate change policy from short-term political pressures; to set clear, binding long-term goals so that investors and consumers understand the emissions trajectory the country intends to follow; and to base decisions as far as possible on technical advice from expert bodies. This sort of approach gives clear long-term signals for investors and consumers and it avoids, or at least reduces, the risk of sudden policy shifts. It also seems to lead to more effective outcomes.
- System optimisation. One area where neither country appears to have made much progress is in system optimisation, especially from the perspective of investment. On the whole, the various policy strands are being treated independently and their consequences (often adverse) dealt with as they emerge. No thought is given at a central level to the overall optimisation of the many resources which will need to be integrated into the more complex system of the future. Additionallly, because these resources are all regulated in a different manner, there is no level playing for competition so markets cannot be relied on to produce an optimum outcome either. The costs, in terms of inefficient investment and consumer opposition could be huge.
- Policy integration. A key problem emerging from the points above is the need for policy integration, namely to think about the impacts of particular policies on the whole system, rather than trying to pursue a range of separate objectives. For instance, if cost containment is not built into the system from the start, costs may quickly prove unsustainable; if support is given for one form of generation it will impact, often negatively, on other forms, leading to a distorted investment climate, which in turn requires remedial action – and so on. One bandage covers another bandage, without curing the original wound, which continues to fester. One way of achieving better policy integration would be, as in relation to overall governance, to develop arrangements which provided for stronger technical input; fuller consideration of the medium and longer term consequences of policy options; and ways of optimising the system as a whole rather than focusing on specific areas.

Section 2 – Institutions and Governance

This section looks at the changes in institutions and their roles which have taken place in response to the imperative of decarbonisation. The challenges for electricity have been profound and while there have been some changes at institutional level, it is likely that significant further evolution of governance will be needed.

2.1 Electricity Sector Governance and Institutional Development

2.1.a Introduction

The two key underlying trends shaping the 'new era' – liberalisation and decarbonisation – do not necessarily conflict with each other, but there are certainly potential tensions which can be particularly acute in relation to the governance of the energy sector. Before liberalisation, governments had guided or controlled the energy sector, often according to a national energy plan. The sector was dominated in many countries by nationalised industries which operated in cooperation with governments to deliver these plans. Moreover, since these corporations generally enjoyed a monopoly of supply, either nationally or regionally, government preferences about, for instance, the choice of fuels for power generation, could be implemented directly without undermining the industry's finances and costs were simply passed through to consumers.

This all changed with liberalisation and privatisation where the aim was essentially to get governments out of direct decision-making. The classic statement of the goal as established early on, in the 1980s when Nigel Lawson, then UK Secretary of State for Energy, described the government's role in the following terms: 'I do not see the Government's task as being to try to plan the future shape of energy production and consumption…rather to set a framework which will ensure that the market operates in the energy sector with a minimum of distortion.' (Lawson 1982) For many years, this was the general approach to energy sector governance – that the government's role was essentially to set the 'framework conditions' within which companies would operate, not to have a fully developed plan for energy. This included decisions about the choice of the generation mix and how much needed to be built. But when decarbonisation emerged as an overriding imperative, it tended to push in the other direction. Given that it involved dealing with 'the biggest market failure of all time' (Stern 2006), some form of intervention in the energy sector was needed if the aim of a lower carbon system was to be delivered. Increasingly, that intervention took on the form of quantitative targets (for emissions, for the share of renewables and so on) with associated policy instruments, designed to achieve the required results.

The interventions were focused particularly on electricity, where low carbon options are available, and where changes can be made upstream without directly affecting consumers. However, electricity has inherent system characteristics – an intervention at one point in the system (for example supporting the development of renewable sources) is not neutral. It affects the whole operation and dynamics of the system, leading to changes elsewhere (for example through its effects on the wholesale market, leading to increasing pressure for capacity payments as discussed in Section 5.4). So one intervention tends to lead to another, and governments are increasingly driving nearly all investment in the electricity sector, which raises the question of whether they need to get more serious about system planning. Should their interventions be based on an overall strategic plan for the sector, rather than simply a renewables objective in isolation? Who will coordinate the investment and ensure optimum system development? If it is to be the government, do they have the capacity to develop and implement such a plan? If it is the network owner or system operator, what conflicts of interest does that create, and is it consistent with the unbundling which formed a central plank of liberalisation to give a single body within the industry a central directing role? Or is a new energy agency or system architect needed – an independent agency which could plan the system in a neutral, technocratic fashion? And should this planning and regulation be national, regional or EU-wide?

The issues extend to the wider question of the role of markets. Is this new emphasis on planning compatible within a basically liberalised market or are more fundamental reforms needed? Should the

aim be simply to ensure that the transition to a low carbon system takes place, then allow the government to step back or will continuing intervention be required? Governments have tended to skirt around these fundamental questions. Interestingly, the first White Paper on electricity market reform in the UK was called 'Planning our electric future' (HMG 2011). Despite that title, and despite the fact that it seemed to herald a full-scale reform of wholesale electricity markets, it did not in fact constitute an overall plan or new market design. Instead, it consisted essentially of a series of measures designed to give incentives for low carbon investment in electricity. Successive UK governments have expressed the goal of returning to competitive market-based structures as soon as possible. Meanwhile, the government is driving electricity investment without any overall coordination mechanism or means of optimising the mix.

Similarly, the EU has focused primarily on the development of the Single Market without giving extended consideration to the implications of the low carbon investment it is simultaneously encouraging. (OIES 2016a) There have been calls for more comprehensive and integrated planning of the various strands of energy and environmental policies, but in the view of many, the proposals for an Energy Union go only a little way towards this objective. There is a marked contrast between the ambitious goals of the Energy Union and the Commission's lack of delivery mechanisms (OIES 2015a; Buchan and Keay 2016; Froggatt and Hadfield 2015).

But the new challenges do not lie solely at the level of high level planning – they also affect the operation of the system at a more direct level. As the penetration of intermittent renewables increases, the tasks of balancing and ensuring system stability get more complex, perhaps reinforcing the case for separating the roles of transmission network owner and system operator (which are combined in some countries). The growth of distributed generation may give new emphasis to the need for a fully developed distribution system operator (DSO), at present little more than a nominal function in many countries.

The various uncertainties and inconsistencies discussed above have led many to argue that there is a deficit of governance – that the energy system remains half-planned, with no clear sense of direction, and that it is caught in the worst place of all: neither a market-based system nor a planned one. However, steps towards a more coherent overall approach remain sporadic; the overall picture is of governments not wanting to give up either of their big goals – liberalisation and decarbonisation – but unsure how best to reconcile them in practice.

2.1.b UK

The UK was one of the first countries to try to develop a new governance structure. The Climate Change Act (CCA) 2008 was an innovative measure passed with all party support, which had three broad aims:

- To insulate climate change policy from short-term political pressures
- To set clear, binding long-term goals so that investors and consumers could understand the emissions trajectory the country intended to follow.
- To base decisions as far as possible on technical advice from expert bodies.

By and large, the approach has been extremely successful, as discussed below.

The CCA sets a binding target for the year 2050 of an 80 per cent reduction in greenhouse gas (GHG) emissions as compared with 1990 levels, and also provides for the establishment of a trajectory to that goal based on five year 'carbon budgets'. These are defined as a level of emissions to be achieved over each succeeding five year period, a length of time which should allow short-term fluctuations, due to weather and other uncertainties, to average out. The budgets are set with advice from the Committee on Climate Change (CCC), also set up under the Act, which advises the Government and reports to Parliament on progress in reducing emissions. Once the budgets have been agreed, they are also binding. The Secretary of State has a duty, first to set the carbon budgets – for periods of at least twelve years ahead – and then to ensure that emissions do not exceed that budget.

It may seem odd for the government to commit itself in this way, but it is much more than window-dressing. The government would face big political difficulties if it did not accept the advice of the CCC or meet the emissions reduction targets; furthermore, the possibility of legal enforcement is real. In a separate but comparable area (clean air) the UK government has been forced by the courts to take action to meet target levels of air pollution following a judicial review brought by a non-governmental organisation. Much the same threat arises with GHG emissions: if it appeared that the government did not have credible policies to meet future carbon budgets the courts could force it to introduce new measures. In practice, as noted in the following section, the UK has so far been largely successful in meeting its own targets, which are more ambitious than those required by the EU.

Unfortunately, perhaps, the UK has not followed up this pioneering institutional achievement in specific sectors. For instance, its electricity market reforms are less far reaching than they might sound. They do not involve the establishment of new bodies, rather the government and the network owner, the National Grid ('Grid'), have shared most of the new functions between them, such as designing and operating the capacity market, running the Feed-in Tariff auctions and so on. Meanwhile, the Grid's role as system operator has grown with the penetration of intermittent sources. Constraint and balancing costs have increased rapidly as have what used to be relatively minor elements of ancillary services (like black start – the cost tripled to £113 Million in 2016, way above the Ofgem cost target[2]). This has led to questions about whether its various roles may involve conflicts of interest and whether the system operator role in particular should be separated out (HC 2016). A Parliamentary Select Committee has recommended the establishment of an Independent System Operator, separate from Grid as the owner of networks, but in practice the regulator has been cautious. Ofgem intends to set up the System Operator as a separate subsidiary within the Grid, rather than split it off completely[3]. This seems to reflect earlier comments by a government minister to the Select Committee, whereby he stated that the options were under examination: 'Those range from "stick with what we have" to a fully independent system operator. We are looking at models elsewhere in the world and the Committee will be aware that in the States they have fully independent system operators. There are strengths and weaknesses of all models and there is a kind of possible "best of both worlds" or you might call it a halfway house, depending on your perspective, where you would have much greater independence but within the National Grid umbrella.' (HC 2016) Whether a halfway house is really the best of both worlds remains to be seen.

Other (relatively minor) changes being considered by the government include the role of the regulator Ofgem in relation to energy efficiency (which had been threatening to unbalance its activities), (Rutledge and Wright 2010, ch 10).

However, these cautious moves are indications of the reluctance with which the government is approaching any further institutional development. This is despite the fact that many in the UK have questioned whether there is sufficient expertise, coordination and direction in the overall governance arrangements, and indeed a special programme to look at issues of governance (IGov) has been set up at the University of Exeter. Proposals for change include the idea of an energy agency to coordinate developments at a national level, secure from political interference (Helm 2001), or of 'system architects' at a national and local level to promote coherent overall development[4].

At the time of writing, however, it seems unlikely that there will be major developments in this area, partly because governments never like ceding power to outsiders, but also because of the continuing desire to phase out intervention in the medium term and return to something like the Lawsonian ideal of government as framework setter rather than planner. Under that scenario, markets would do the coordination and consumers would participate by responding to price signals, so there would be no need for new bodies and agencies.

In fact, the government does not really seem to have a clear view of the role of markets in the energy sector. On the one hand it frequently declares its wish to return to non-intervention once the low

[2] http://utilityweek.co.uk/news/national-grid-spent-113m-on-black-start-contracts-with-drax-and-sse/1250662#.V6BuBaJRh34
[3] https://www.ofgem.gov.uk/publications-and-updates/greater-separation-national-grid-s-system-operator-role
[4] See, eg http://projects.exeter.ac.uk/igov/the-belly-of-a-system-architect/

carbon system has been achieved; on the other, its interventions continue to be based on the achievement of specific outcomes. While it has moved increasingly to auction arrangements, its support for low carbon sources remains largely technology specific. In the capacity market, as discussed in Section 5.4, it has sought to rely as far as possible on market forces by using technology neutral auctions but has apparently been dissatisfied with the results. Consequently, it is now seeking to tweak the arrangements to encourage the outcome it had wanted in the first place, namely the construction of new gas-fired plants.

Overall, it is not clear that the government has thought through the problem of how to get off the treadmill of intervention. Without any clear 'exit strategy' from the process it is difficult to see how a sustainable system based on market forces alone could be developed (OIES 2016a). Yet without some energy equivalent of the CCC, it may not be possible to develop and implement the sort of changes in policies and institutions which could lead to that result. At the moment the UK seems to be stuck in an uncomfortable halfway house between a preference for markets and the constant need for intervention (Keay 2016).

2.1.c Spain

Spain has done very little to reform its governance of the electricity sector, either in providing long-term (out to 2050) policy guidance for climate change or for the needed decarbonisation of the entire energy system. There is no equivalent to the UK Climate Change Act, nor any independent body like the CCC[5]. Nor has there been any substantial reform of the regulatory governance of the sector or of electricity markets specifically in response to the challenges of climate change. There have been institutional changes to the regulatory authorities responsible for energy, but these have not altered significantly the role of the regulator nor been in response to the challenges of climate change.

The governance arrangements continue to give central government the primary decision-making power on most matters related to the sector, either directly or indirectly. Directly, the government decides how to meet climate change and other environmental objectives that are usually determined by the EU, how the sector will be regulated, what policy costs will be recovered through tariffs, what network tariffs will be for different customer groups, how markets will be organised, and what networks and interconnectors will be built. Indirectly through the political process for selecting commissioners for regulatory and competition authorities, the government influences decisions related to mergers and anti-trust. In short, although Spain formally embraced the liberalisation model in the late 1990's, governments have intervened heavily ever since. Indeed, direct government intervention has become more important since decarbonisation became a new policy priority. There is no evidence that the current government wishes to give up the levers of control or to adopt a Lawsonian model where markets drive decisions.

In spite of the heavy intervention, markets are an important part of the governance structure in Spain, at least in three respects. Firstly, Spain actively supports the creation of a Single European Market for electricity and gas. The Iberian electricity market (Spain and Portugal) has already been coupled with the other parts of the European Single Market in the sense that they are using the same formula for establishing prices for day-ahead trading. In practice, however, the very limited interconnection between Spain and France restricts trading between Spain and the rest of continental Europe. Consequently, one of Spain's principal expressions of enthusiasm for liberalisation is to exert as much pressure as possible on the EU to support (and finance) an increase in interconnection between France and Spain. Spain is especially interested in the potential that additional electricity interconnection would offer to export renewable energy, in addition to the other traditional benefits of interconnection (for example, security, competitive pressure on prices)[6].

[5] The government has announced its intention to develop legislation to address climate change and energy transition. http://www.lamoncloa.gob.es/serviciosdeprensa/notasprensa/magrama/Paginas/2017/180117-clima.aspx

[6] It is, however, interesting to note that an increase in wholesale prices in Spain in January 2017 was partly caused by a jump in exports due to outages of nuclear power plants in France. This led some commentators in Spain to call for a ban on exports to France in exceptional circumstances.

Secondly, wholesale electricity markets work efficiently within the Iberian Peninsula, at least with respect to optimising short-term despatch across the peninsula. The *Operador del Mercado Ibérico* (OMIE)[7] manages the daily and intraday markets for the entire peninsula. Evidence of the successful integration of these markets is that day-ahead prices between Spain and Portugal are the same more than 90 per cent of the time. Spain has also been successful in integrating intermittent renewable energy into the wholesale energy market. In part this has been due to sufficient network capacity and the control exerted by *Red Eléctrica de España* (REE) over system operations. It is also due to abundant hydro and Combined Cycle Gas Turbine (CCGT) capacity and to incentives (both market and regulatory) for intermittent renewable operators to meet their day-ahead commitments and, more recently, to participate in ancillary service markets.

In spite of the efficiency of short-term wholesale markets, it is mainly government decisions rather than wholesale markets that drive investment in new renewable generation capacity, especially through out-of-market payments. Nevertheless, even when it intervenes, the government increasingly relies on market mechanisms to determine prices and award contracts. For instance, for some years, the government used a central auction[8] to determine the quarterly price for wholesale energy required to supply small consumers who were buying electricity on a last-resort tariff. More recently, the government has used auctions to determine the price and the suppliers of 'interruptible' electricity. Although these auctions for interruptible supplies are widely regarded as a way of subsidising large industry, they at least introduce an element of competitive market logic to how this is done. The government also held an auction for 700 MW of renewable energy in 2016, with a surprising result: no need for any additional payment beyond the energy spot price. Various explanations have been offered for this result, most of which suggest that it will not happen again. We shall soon find out: the government has recently announced plans for an auction for 3000 MW of renewable energy to be held in the first half of 2017. Unlike previous auctions for renewable power, this one will be technology-neutral[9].

Thirdly, retail markets are increasingly governed by competition. Approximately sixteen million consumers have chosen to buy electricity under contracts whose prices and terms are freely determined. Almost all of the remaining eleven million consumers buy their electricity through a regulated formula that passes on the hourly price of electricity in addition to regulated costs. This is not formally a regulated tariff, but rather a regulated formula that gives consumers a short-term price signal. However, all consumers are obliged to pay for a series of policy-related costs that are included in the access tariffs; in that way, the government continues to control electricity prices for all consumers.

There is one feature of the Spanish system for governing the sector that sets it apart from most countries, namely the powers given to the Autonomous Regional governments. These governments have the authority to approve renewable power projects within their territories, and to introduce taxes on certain emissions. However, if the central government does not offer financial support for renewable power projects, it is very unlikely that the projects will proceed.

Spain's new political and economic situation could change or influence the governance of the sector. For instance, Spain will face increasing pressure from the EU to reduce greenhouse gas emissions and it is now possible that a cross-party majority could be formed to pass legislation on climate change and the energy transition[10]. To date, Spain's ghg emissions are about 15 per cent higher than 1990 and they would have been substantially higher were it not for the economic crisis that began in 2008. Recently, the EU proposed that Spain reduce emissions from its diffuse sectors by 26 per cent in 2030, compared to 2005 levels. Although many groups think the reduction for the diffuse sectors is unambitious, arguing that they have already reduced emissions since 2005, in fact it will be quite a

[7] http://www.omel.es/en/home/information-company

[8] Known as the CESUR (Contratos de Energía para el Suministro de Último Recurso) auction.

[9] These auctions are discussed in more detail in Section 3.1.c.

[10] The President of the government announced in his speech of investiture the urgent enactment of a Law on Climate Change and the Energy Transition. However, we have yet to see the proposed text of such a law.

challenge if the Spanish economy grows as anticipated[11]. Emissions reduction for facilities in the Emissions Trading System (ETS) sectors will be even more ambitious. With or without a Climate Change and Energy Transition Act, there is a growing recognition that Spain needs to consider its long-term future strategy, whereas for at least the past five years the country has been concentrating almost exclusively on addressing the problems of the past and the immediate future.

In summary, Spain - like the UK - seems to be stuck in an uncomfortable halfway house between markets and intervention. But there are differences. In Spain, the commitment to electricity markets has always been weaker than in the UK and the power of political intervention much stronger. One could argue that the Spanish government sees market mechanisms as a way of reducing the costs of meeting specific short-term objectives, such as EU renewables targets, rather than as means of promoting innovation and meeting broad long-term policy objectives. Indeed, in the absence of any long-term policy guidance on climate change or decarbonisation of the energy sector, market mechanisms tend to result in a different form of intervention rather than being a means of promoting a framework to ensure that the market operates in the energy sector with a minimum of distortion.

2.1.d Conclusions

In some respects the overall UK approach seems to be a useful model. It has helped to produce a clear long-term trajectory for emissions and has, to a significant extent, shifted the decarbonisation debate from the political to the technical arena. Nonetheless, there remains an overall uncertainty about the extent to which markets will play a part in the process, which has been exacerbated by the tendency to indulge in ad hoc interventions in response to particular problems. Furthermore, the government has been reluctant to extend its institutional innovation more widely. In Spain, the preference for political intervention is more clearly established and there has been less attention paid to the longer term, in particular with respect to climate change and the energy transition. In both countries the future challenges could in many ways be greater than those of the past as policy has to get beyond the (relatively) low hanging fruit of energy efficiency and electricity decarbonisation. It seems likely that further institutional change will be needed to respond to these challenges.

2.2 Progress with decarbonisation

2.2.a Introduction

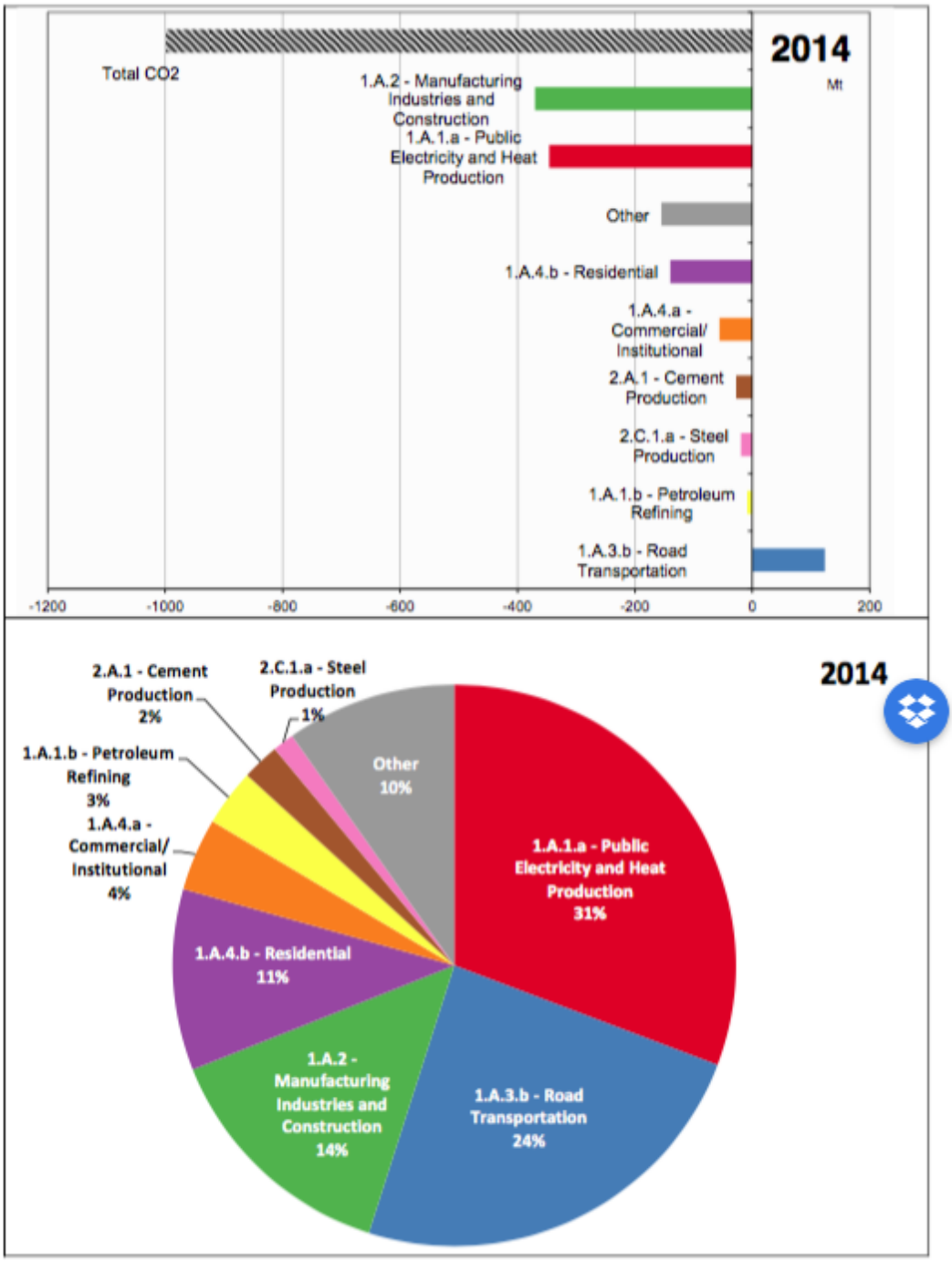
A key EU objective is to achieve economy-wide decarbonisation. For the first Kyoto period (2008-2012), the EU committed to an 8 per cent reduction of GHG emissions by 2012 compared to 1990 levels. For the second Kyoto Period (2013-2020), the commitment was for a 20 per cent reduction in GHG emissions compared to 1990. For both periods, a main instrument for emissions reductions was the EU Emission Trading System (ETS), which accounts for about 45 per cent of emissions, including those from electricity, with different measures used for the more diffuse sectors (like transportation, buildings, and agriculture).

In 2011, the EU confirmed its non-binding political commitment to reduce GHG emissions by 2050 by 80-95 per cent compared to 1990 levels. In 2015, it signed and then later ratified the Paris Agreement, which commits to achieving carbon emission neutrality between 2050 and 2100. The EU has also made a legally binding commitment to achieve a 40 per cent reduction in GHG emissions by 2030. The 2030 commitment leaves the heavy lifting for the period after 2030.

To date, electricity has played an important role in the decarbonisation of the energy sector. This is partly because of the significance of the emissions from electricity, but is also due to the significant decline in those emissions since 1990. Chart 2 reflects that emissions from electricity and heat fell by 25 per cent between 1990 and 2014, whereas emissions from road transport rose over the same period.

[11] The decline in energy demand and emissions is linked to the economic crisis. A sustained economic recovery could very well lead to significant increases in emissions, for instance in transport.

Chart 2: Absolute Change of GHG emissions in CO2 equivalents (Mt) by large key source categories for 1990-2014 and share of largest categories in 2014



Note: Other is calculated by subtracting the presented categories from the sector total

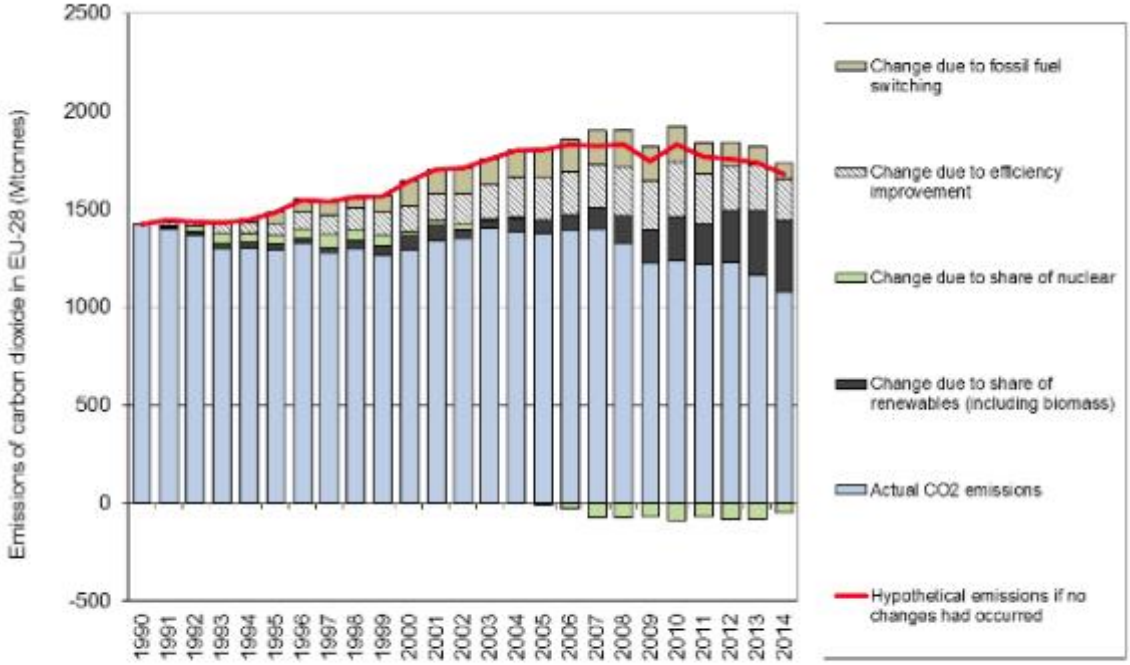
Source: EEA 2016, page 84.

Chart 3[12] illustrates a number of factors that explain the decline in emissions in the electricity sector. Emissions from public heat and electricity production, represented by the blue bars, decreased by 25 per cent between 1990 and 2014, but it was estimated that they could have risen by over 18 per cent,

[12] EEA 2016, page 109.

as represented by the red line, had there not been improvements in energy efficiency, a switch away from fossil fuels, and an increase in renewables. Energy efficiency (namely primary energy input per unit of electricity generation from fossil fuels) improved by 16 per cent; the switch from coal to gas reduced CO2 emission per unit of fossil fuel input by 7 per cent; and the share of fossil fuels fell by 18 per cent largely as a result of increased renewables output.

Chart 3: Estimated impact of different factors on CO_2 emissions reductions from public electricity and heat production, 1990-2014



Note: The chart shows the estimated contributions of the various factors that have affected emissions from public electricity and heat production (including public thermal power stations, nuclear power stations, hydro power plants and wind plants). The top line represents the hypothetical development of emissions that would have occurred due to increasing public heat and electricity production between 1990 and 2014, if the structure of electricity and heat production had remained unchanged since 1990, i.e. if the shares of input fuels used to produce electricity and heat had remained constant, and if the efficiency of electricity and heat production also stayed the same. However, there were a number of changes that tended to reduce emissions. The contribution of each of these changes to reducing emissions is shown by each of the bars. The cumulative effect of all these changes was that emissions from electricity and heat production actually followed the trend shown by the blue bars. This is a frequently used approach for portraying the primary driving forces of emissions. It is based on the IPAT and Kaya identities. The explanatory factors should not be seen as fundamental factors in themselves nor should they be seen as independent from each other. The underpinning energy data is based on Eurostat's energy balances.

The early focus on electricity can be explained quite easily. Technically and economically, electricity is easier to decarbonise than the other major sources of CO_2 emissions. Initially, electricity had relatively few but very large, stationary emission sources, particularly coal-fired power stations. The energy from those stations could be replaced within the same electricity network and at a reasonable cost by lower carbon alternatives, including electricity generated from nuclear power, natural gas and renewables. It is much more difficult to replace fossil fuels in sectors where emissions are the result of hundreds of millions of decisions and where new distribution networks (for example, charging stations for electric vehicles) are required to facilitate the transition away from fossil fuels. Politically, it was also relatively easy for governments to decarbonise power. Governments decided how much and what type of low carbon capacity to build and then socialised the financing of these investments through tariffs or taxation. The far-reaching consequences of electricity decarbonisation were not fully understood when the process began, and we are now living with the need to reform fundamentally the markets and regulation of the sector. Two of these consequences have been a substantial increase in costs recovered through electricity tariffs, and the undermining of wholesale energy markets; both of these have led to a slow-down in the process of decarbonising electricity in the EU.

The extent and the nature of decarbonisation of electricity vary significantly from one country to another. This is partly because of different starting points, with the less developed EU countries, such as Spain, initially allowed to increase absolute emissions to reflect existing lower per capita emissions and anticipated economic growth, while the wealthiest nations, such as the UK, agreed to reduce their emissions. Each EU member state also began with a specific mix of generation and with different domestic resources to exploit. Variations also reflect national political decisions, for instance to emphasize a reduction in overall emissions in a long-term plan, as seen in the UK, or to focus on an early increase in renewable power, as Spain did.

In this report, we focus mainly on how governments have dealt with the many challenges of decarbonising the electricity sector. In this section, we compare their progress on decarbonising the sector.

2.2.b UK

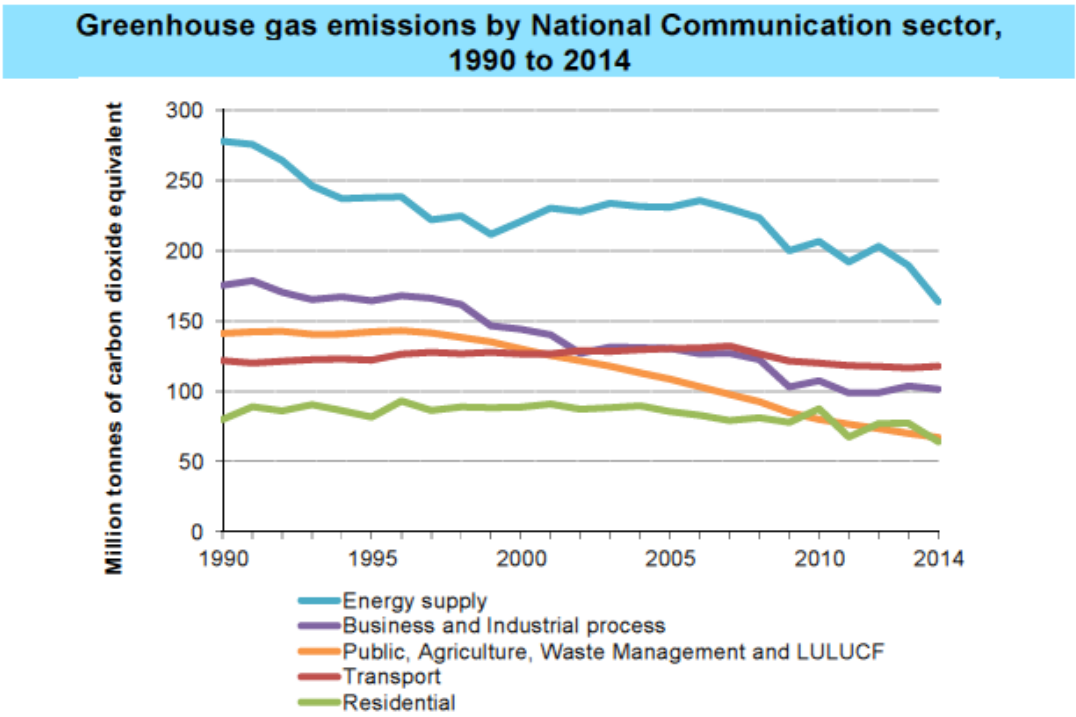
As noted above, the UK has what is probably the most systematic approach to greenhouse gas emissions reduction of any country in the world. Whether or not as a direct result, the UK has so far been considerably successful in progressing towards its targets. Emissions were 38 per cent below 1990 levels in 2014 according to the CCC (CCC 2016) and the UK was on track to outperform the second and third carbon budgets. However, the CCC also noted that the UK was not at present on track to meet the fourth budget, which covers the period 2023-27 (or the fifth budget, set in mid-2016, which aims at a 57 per cent reduction for the period 2028-2032).

Indeed, it is likely that the challenges in meeting the targets will increase significantly during the 2020s and beyond. The UK's strategy for decarbonisation is based on advice from the CCC which could be summarised as 'decarbonise electricity first'. (In its 2008 report it argued that for the UK, 'any path to an 80 per cent reduction by 2050 requires that electricity generation is almost totally decarbonised by 2030' (CCC 2008 p173). The original idea was that once electricity had been decarbonised it could gradually replace fossil fuels in heating and transport, but that strategy looks increasingly difficult as it gets examined in greater detail (for example Eyre and Baruah 2015, Winskel 2016).

Nonetheless, the fact that the system will be tested to a greater extent in the future should not detract from its considerable success to date. As noted above, UK emissions in 2014 had more or less reached the EU 2030 target (and, subject to confirmation when figures are available, will have almost certainly done so in 2016 as the downward trajectory in electricity emissions continued during that year as renewable output grew and coal stations closed. In 2016, for the first time ever, wind generation exceeded coal generation.)

The latest figures available are shown below in Chart 4:

Chart 4: UK GHG emissions



	Million tonnes of carbon dioxide equivalent					
	1990	**1995**	**2000**	**2005**	**2010**	**2014**
Energy supply	277.9	237.9	220.9	231.0	206.7	163.8
Residential	80.1	81.7	88.7	85.7	87.6	64.2
Public, Agriculture, Waste Management and LULUCF	141.3	142.3	130.3	108.7	80.1	67.1
Business and Industrial process	175.5	164.4	144.1	130.5	107.6	101.5
Transport	121.9	122.2	126.7	130.4	120.1	117.9
Total greenhouse gas emissions	796.6	748.5	710.6	686.3	602.1	514.4

Source: Ricardo Energy and Environment, BEIS (2014 final figures)
LULUCF – land use, land use change and forestry
All figures are for the UK only and exclude Crown Dependencies and Overseas Territories

The biggest reductions have indeed been in electricity generation (which accounts for the bulk of the 'energy supply' line above) but other sectors (apart from transport) have also seen considerable falls in emissions (though again future reductions may be more challenging. For instance, much of the reduction in the 'Public etc' line on Chart 4 is from reductions in methane emissions, which cannot continue indefinitely).

Overall, however, the record to date is very good – reductions have been achieved ahead of target in nearly all sectors and progress far exceeds that of most other countries in the EU (like Spain). Furthermore, there has been no obvious impact on the economy. Since the mid-2000s (ie shortly before the CCA approach was introduced) the UK economy has grown at about twice the rate of the EU in general – or Spain in particular. While many factors are of course involved in this comparison, it is clear that the major reductions in emissions have not in themselves been a significant restraining factor on growth.

2.2.c Spain

Spain's commitments with respect to GHG emissions reflect the fact that EU targets were more generous for less wealthy member states. The argument for being generous was that more rapid economic growth would inevitably imply rising emissions; which turns out to be a self-fulfilling prophecy. Spain committed to limit its growth in GHG emissions to 15 per cent in the first Kyoto period (2008-2012) compared to 1990 levels, but had to purchase allowances under the flexibility mechanisms in order to meet that commitment. Reflecting its rapid economic growth, Spain's emissions in 2005 were more than 50 per cent above 1990 levels. Largely as a result of the economic crisis, Spanish GHG emissions fell sharply after 2007, but in 2015 were still 15 per cent higher than in 1990.

Spain's commitments to the EU for 2020 are to reduce GHG emissions in non-EU ETS sectors by 10 per cent compared to 2005 levels; to reduce energy consumption by 20 per cent compared to an assumed trend measured from 2005; and to obtain 20 per cent of primary energy consumption from renewable sources. These obligations are in addition to the required 21 per cent reduction in emissions by companies operating in sectors covered by the EU ETS, including electricity, between 2013 and 2020.

According to the European Environment Agency (EEA), Spain's emissions from the non-EU ETS sectors and the level of energy consumption in 2015 were consistent with meeting the 2020 targets. However, these targets were set by reference to 2005 levels, when Spain's GHG emissions were over 50 per cent higher than 1990, and are much less ambitious than targets for the UK. Furthermore, the EEA forecast that emissions from the non-EU ETS sectors in Spain would remain flat or rise from 2016 to 2020 and that energy consumption would continue to rise. In addition, whether or not Spain meets its 2020 targets, it would be difficult to argue that it was on track for the EU's 2050 target – and, as noted in the UK section, the defence that Spain, as a less wealthy country, needed more headroom for growth, is not convincing. Indeed, because Spain's GHG emissions have risen since 1990, it has a heavier load to bear in future to achieve the EU-wide 2050 target of reducing GHG emissions by over 80 per cent compared to 1990.

Spain has made more progress with respect to its renewable energy target, mainly through the penetration of renewable power. In 2016, 17.6 per cent of primary energy came from renewable sources. The share of renewables for heating and cooling rose from 9.4 per cent in 2005 to 14 per cent in 2012 and the share of renewables for transport has been negligible. Meanwhile, the share of renewable energy in electricity has risen from 19.1 per cent in 2005 to approximately 40 per cent in 2016. The government has just announced an auction for 3 GW of renewable power to be held in the first half of 2017; this is likely to enable Spain to meet is 2020 target for energy coming from renewable sources, although this is not yet certain[13].

Largely as a result of the penetration of renewable power, the share of electricity from fossil fuels fell from 66 per cent in 2005 to 39 per cent in 2014. This reduced the carbon intensity of generation, which fell from 402 to 255 gCO_2/kWh over that period, roughly 37 per cent. However, the main decline in carbon intensity occurred by 2010, and has fluctuated since then. In 2014, it was higher than in 2010.

[13] The renewable capacity being built in the period 2015-2020 with support of government auctions is approximately 3700 MW, less than half the amount (8500 MW) that was included in the plan for the same period.

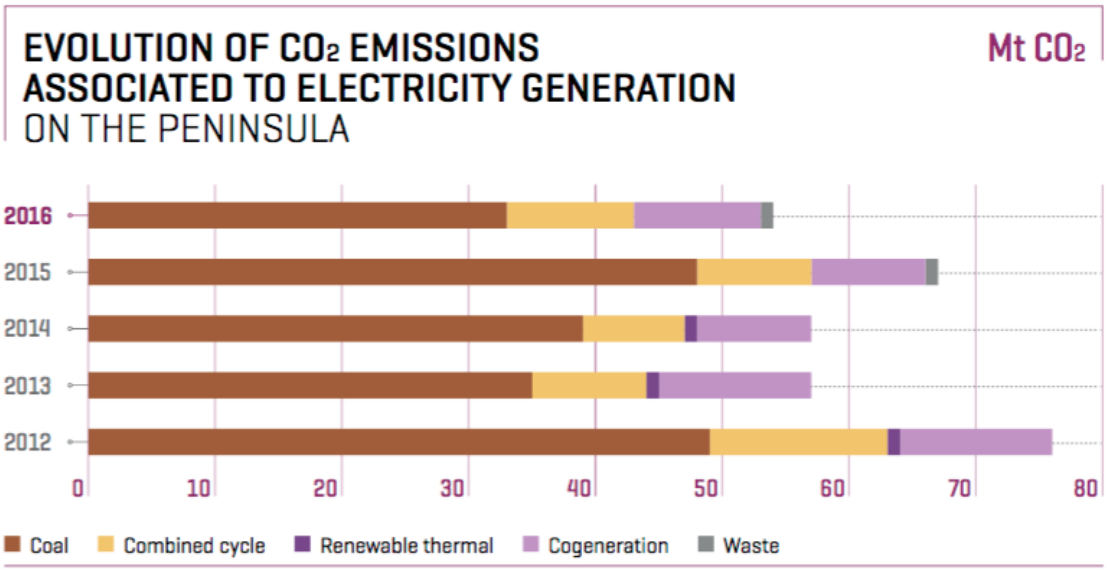
Chart 5: Spain key indicators: 1990-2014

	1990	1995	2000	2005	2010	2013	2014	90-14
CO_2 fuel combustion ($MtCO_2$)	202.60	228.17	278.53	333.63	261.98	235.09	231.99	15%
Share of World CO_2 from fuel combustion	0.99%	1.07%	1.20%	1.23%	0.86%	0.73%	0.72%	
TPES (PJ)	3 771	4 220	5 102	5 942	5 349	4 903	4 796	27%
GDP (billion 2010 USD)	873.15	940.94	1 149.49	1 358.05	1 431.59	1 357.06	1 375.52	58%
GDP PPP (billion 2010 USD)	919.64	991.05	1 210.71	1 430.37	1 507.83	1 429.33	1 448.78	58%
Population (millions)	39.34	39.72	40.55	43.66	46.56	46.59	46.46	18%
CO_2 / TPES (tCO_2 per TJ)	53.7	54.1	54.6	56.1	49.0	47.9	48.4	-10%
CO_2 / GDP ($kgCO_2$ per 2010 USD)	0.23	0.24	0.24	0.25	0.18	0.17	0.17	-27%
CO_2 / GDP PPP ($kgCO_2$ per 2010 USD)	0.22	0.23	0.23	0.23	0.17	0.16	0.16	-27%
CO_2 / population (tCO_2 per capita)	5.15	5.74	6.87	7.64	5.63	5.05	4.99	-3%
Share of electricity output from fossil fuels	47%	52%	56%	66%	46%	40%	39%	
CO_2 / kWh of electricity (gCO_2/kWh)	436	462	441	402	240	245	255	-41%

Source: IEA 2016, p. II.375

Fluctuations in the carbon intensity and total CO_2 emissions related to electricity generation reflect a number of factors, some of which can be seen in Chart 6. Firstly, a moratorium on support for new renewables in 2012 slowed the growth in renewable capacity and output. Secondly, in the other direction, declining electricity demand until 2014 contributed to lower carbon intensity because renewables usually run first in the merit order. Thirdly, higher renewable output in very wet and windy periods reduced carbon intensity and emissions, for instance in early 2016, while the opposite happened in dry and less windy periods. Finally, a key determinant of carbon intensity and emissions was related to competition between fossil fuels. With low world coal prices, financial support for domestic Spanish coal and low EU prices for CO_2 emissions allowances, coal replaced natural gas, resulting in rising carbon intensity.

Chart 6: CO_2 emissions from Spanish electricity: 2009-2016 (million tonnes CO_2)



Source: REE 2016.

To sum up, Spain may meet its 2020 GHG commitments to the EU, but a large part of that 'success' is related to its prolonged economic crisis and relatively unambitious targets by comparison to the UK. Renewable electricity contributed in a significant way to the decarbonisation of the energy sector after 2007, but this was fairly short-lived success. Indeed, electricity sector emissions have not fallen much since 2010 and the carbon intensity of the sector has increased since 2010, reflecting limited growth

of renewable output and a fossil-fuel shift from natural gas to coal in some years. Spain's decarbonisation challenges will become more difficult because its targets are now more demanding and because demand has begun to grow again along with the economy. This will involve continued decarbonisation of electricity, which already produces over 60 per cent from non-fossil sources. However, decarbonising transport and buildings will be much more challenging because these end markets rely on fossil fuels and have millions of consumers whose behaviours will be extremely difficult to change.

2.2.d Conclusions

While the UK's success in reducing emissions can be attributed to a number of factors, including a switch from coal to gas in power generation and a deindustrialising economy, it is also due in large part to the effective governance arrangements the UK has established, which have encouraged a clear focus on long-term emissions reductions (as opposed to short-term political objectives or intermediate targets, like the share of renewables). Nonetheless, both countries will clearly face greater challenges in achieving future emissions reductions and it remains to be seen whether the UK system will remain robust.

2.3 Role of the Regulator

2.3.a Introduction

Independent regulation has always been at the heart of the 'standard model' of electricity liberalisation (see, for example, OIES 2016 b). Traditionally, two main characteristics have defined the role of the regulator:

- Independence from government: the role was seen as essentially a technical one; it was important to maintain the regulator's independence in order to limit the possibility of political interference.
- Focus on economic efficiency: the role of the regulator was seen as narrow and essentially economic – in the words of one former regulator 'to simulate and stimulate' competition, that is, to regulate the monopoly parts of the industry (the networks) so as to prevent the abuse of monopoly power. They were also required to set prices at a level which would be fair to all concerned (in some sense reproducing the price levels that might have been set in a competitive market) and to promote competition (for example, by third party access to infrastructure) where possible.

The rationale for this approach is to ensure that consumers' interests are protected, to reassure investors that they will have a reasonable chance to earn a return on their investments if they operate efficiently, and to provide certainty by delegating decisions to an expert authority which will make decisions according to clear criteria.

The first of the objectives described above (namely independence) has not always been met fully in practice, especially in southern European countries, but it remains the theoretical goal. In most cases the second objective – the focus on economic efficiency – was central both in theory and practice, at least in the early stages of liberalisation. Indeed some countries did not create separate electricity (or energy) regulators but gave the task to general economic regulators or to competition agencies.

However, this simple model has come under strain in the 'new era', forcing some reconsideration of the regulatory role. Economic efficiency and competition can no longer be the sole consideration when government policy is to promote certain (generally uneconomic) sources by non-market means for environmental reasons. Nor is it entirely clear what protecting the interests of consumers means in this new situation – in the past it has usually been taken to mean securing the lowest possible prices consistent with the efficient development of the industry, but in the new situation sources which are not necessarily the cheapest have to be accommodated for environmental reasons. It can be argued that this is in the long-term interests of consumers (though even that is not clear – it is ultimately the global commons which are at stake and the extent to which a particular country's consumers should

help contribute to that goal is essentially a matter of political judgement). In other words political constraints on the regulatory process, if not actual political interference, are inevitable in the new era.

That can be seen in relation to a number of the specific issues discussed in this paper – for instance, the regulation of transmission access and of distribution systems. How far should regulators design the arrangements specifically to accommodate renewable sources rather than simply with the aim of creating a level playing field, for example? This section looks at the wider question – what is the overall role of the regulator in the new era? Are the central goals still independence, economic efficiency and the promotion of competition? How have the UK and Spain responded to the 'new era' challenges and what lessons can be learned?

2.3.b UK

In the early days of UK liberalisation, the approach to regulation was very close to the theoretical ideal model described above – the regulator was clearly independent of government and the role was essentially economic. This approach was much facilitated by the fact that, in Dieter Helm's words 'there was little or no energy policy to make in the 1990s' (Helm, 2003, 124)[14]. Energy markets were then well supplied; the UK was self-sufficient and environmental targets were being met without the need for any major policy effort as gas replaced coal in power generation through the operation of market forces. With no policy to make, there was no need or temptation for political input to the regulatory process – although the regulators themselves did indeed have a lot of work to do in the 1990s in promoting competition and moving towards full market liberalisation.

Matters became more complicated after the turn of the century. Energy prices started rising, the UK started to rely increasingly on imports, and environmental goals became more challenging. This was particularly the case after the Climate Change Act of 2008 which included legally binding overall targets on the government, and the EU's 20/20/20 package (agreed in 2007) which set an extremely ambitious goal for renewable energy in the UK, which would have to be met largely via the introduction of renewable sources in electricity. This risked putting the government on a collision course with the regulator – in the past, regulators had argued that renewables were an expensive way of securing greenhouse emissions reductions and that the extra transmission investment needed to connect them to the grid could not be justified as being in consumers' interests (Helm, 2003, 364-5). The government's response was to amend the regulator's objectives to get away from the exclusive focus on economic issues. It did indeed continue to argue that competition was central but at the same time it suggested that 'there are contexts in which the promotion of competition may not be sufficient' (HMG 2009, 98). It therefore decided to change the regulator's duties to 'clarify' that the original goal of protecting the interests of consumers 'includes security of supply and reducing carbon emissions' (HMG 2009, 98). Meanwhile, the activities of the regulator were also changing. Increasingly it was acting as a delivery agent for government policies designed to promote energy efficiency or environmental goals. By 2010 Ofgem was estimating that fully half of its projected spending would be devoted to 'E-Serve', that is, those activities it carried out on behalf of the government in areas such as the monitoring of energy efficiency schemes (Ofgem 2010).

As time has gone on, there have been other signs of increasing political input to the regulatory process – for instance, the 'Retail Market Review' discussed in Section 3 where both the review itself and the chosen remedies appeared to be a response to political concerns, or the introduction of the 'Connect and Manage' system designed, at some cost, to facilitate the penetration of renewable sources (Section 4).

More recently, however, it appears that there has been a recognition that the process may have gone too far, leading to the desire to move back towards a 'purer' form of regulation. The realisation has grown that the increasing burden of politically determined tasks and objectives may be compromising the regulator's basic role and the objectives noted above.

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[14] There was nevertheless quite a bit to do on the regulatory (as opposed to the policy) front, for instance the promotion of effective competition among generators, which meant encouraging the entry of CCGT's, and limiting the market power of National Power and PowerGen.

In the 2016 budget the government announced a wide-ranging 'simplification plan' designed to clarify and simplify the role of regulation and reduce the burden on businesses. Ofgem described the impact on its own role in the following terms:

'The government is committed to robust but focused economic regulation. The UK's system of independent economic regulation is widely regarded as one of the best in the world. Building on this, Budget 2016 announces that the government will streamline regulators. E-Serve will be split off from Ofgem to ensure Ofgem can focus on its core functions of economic regulation and promoting competition. DECC [the Department of Energy and Climate Change] are committed to consolidating their delivery providers and will set out the future of consumer-facing functions, including those currently undertaken by E-Serve, at Autumn Statement 2016. The government will continue to consider whether economic regulators' functions can be further streamlined'. (Ofgem 2016a)

In other words, although the details have yet to be developed, the overall aim seems clear – to get closer to the traditional, relatively narrow, view of the regulator's functions.

However, splitting out the non-core functions will not on its own be enough to produce clarity about the role of the regulator in the new situation. In a wide-ranging report on energy markets, the UK Competition and Markets Authority (CMA 2016) gives thoughtful consideration to the relations between government and regulator. It notes that:

> 'Government policies…are having an increasing impact on energy prices and bills….Climate and energy policies as a whole are expected to amount to 37% of the retail price of electricity paid by households in 2020'.

When such a large proportion of a consumer's bills is due to government action, how can a regulator carry out its duty of protecting consumers' interests? Part of the solution, of course, lies in measures for cost containment, such as the use of auctions, discussed in Section 5. But the CMA argues that there is also a wider need to reconsider the relationship between the regulator and government and the central regulatory role:

> 'The allocation of powers, roles and objectives between DECC, Ofgem and the industry does not ensure that decisions are consistently made in the interests of consumers in the long term…in particular because:
>
> 1. Ofgem's objectives and duties …. are unclear and may hinder the achievement of customers' interests wherever appropriate through effective competition'

[CMA, 2016, 18.8]

It noted that Ofgem had expressed concern that its competition duty had been 'progressively downrated compared to other duties' [CMA, 2016, 18.11] and looked in detail at Ofgem's duties under the Energy Act of 2010. The CMA regarded them as likely at best to cause confusion, at worst to constrain Ofgem's promotion of competition (CMA, 2016, 18.23). It surveyed the history – including episodes such as the Retail Market Review – and concluded, choosing its words carefully, that 'the coincidence of DECC's and Ofgem's actions is likely to create the perception of a lack of independence on the part of Ofgem' (CMA, 2016, 18.35).

After reviewing a number of such problem areas, the CMA called for a 'reset of the regulatory framework' based on:

- Clear and consistent roles and objectives, aligned with the best interests of customers.
- A reinforcement of the role of an independent and authoritative regulator, and;
- Clear assignment of responsibilities and transparent, coordinated implementation. (CMA 19.10)

In a sense, this proposed reset is a return to the original principles of regulation, but adapted to the new situation where, in the CMA's words, 'it is not reasonable' to expect the government to give up its discretion over policy, on the one hand, or to expect the government and regulator to be in agreement on all aspects of policy on the other (CMA, 2016, 18.41). While the details of the government's

response to the CMA report are not available at the time of writing, the CMA's restatement of principles seems a valuable guide to the way forward.

2.3.c Spain

Spain's approach to the role of the regulator differs from the UK's approach in at least three ways. Firstly, Spain's national regulatory authority, currently the CNMC (*Comisión Nacional de Mercados y Competencia*) has more limited independence from government than Ofgem. Secondly, the CNMC and its predecessors have never had the same degree of authority as Ofgem, especially on matters of importance such as setting access tariffs. Rather, CNMC is an advisor, whose opinion is often required before government takes the final decision. Thirdly, although the CNMC has some administrative responsibilities related to decarbonisation, there is no evidence of a shift in its primary goals, namely to support effective competition, economic efficiency, and market transparency in the interest of all the agents in the sector as well as consumers.

The first energy regulatory agency was called the CSEN (Comisión del Sector Energético Nacional), which was replaced by the CNE (Comisión Nacional de Energía) in 1998. In 2013, the CNE was absorbed along with other sectorial regulatory agencies and the national competition authority to form the CNMC. The CNMC currently has two parts: one is responsible for competition policy and the other for the regulation of various sectors, including electricity and gas[15]. In principle, the two parts of the CNMC coordinate on competition matters involving electricity.

The independence of the CNMC from government is questionable. The President, Vice President and eight Commissioners of the CNMC are elected by Parliament from the candidates proposed by the relevant Ministry. The tradition in Spain is that the selection of candidates for the Commission reflects the political balance of power in Parliament. However, the opposition Socialist Party opposed the creation of the CNMC and the elimination of the sectorial regulators (and the firing of their presidents)[16]. Consequently, in 2013, members of parliament from that party refused to participate in selecting commissioners; consequently, eight of the CNMC's ten sitting commissioners – including the President and the Vice President – were proposed by the government of day. Some of these commissioners will soon be replaced, somewhat rebalancing the political makeup. Nevertheless, the CNMC continues to be less independent from government than Ofgem[17].

The independence of CNMC from government is probably less important than the fact that the CNMC has very limited authority to make decisions that matter. Indeed, the EC has accused Spain of not correctly transposing the EU Directive 2009/72 as it relates to setting access tariffs for transmission and distribution networks. The Directive requires that the National Regulatory Authority (NRA) establishes or approves those access tariffs or at least the methodologies for setting them. However, this is not the case in Spain. There are at least two issues here. Firstly, access tariffs in Spain include two components: the network Use of System (UoS) charge related to the recovery of the costs of the monopoly networks themselves, and levies that reflect the cost of public policies, such as support for renewable energy. In July 2014, the CNMC published its own proposed methodology for setting the UoS charges for the transmission and distribution networks, but it did not have the authority to establish the basis for setting levies. Secondly, in December 2014, the government passed legislation giving it the authority to establish access tariffs, including both the network charges and the levies; at the same time, it changed the consumer categories that the CNMC had used in its proposed methodology for UoS charges. In this way, the government effectively took over the one potentially

[15] The Government is currently negotiating with opposition parties the separation of these two divisions into two separate authorities, one for regulation and the other for competition, each with its own President. (*Periodico de la Energía*, 30 December, 2016.)

[16] The European Court of Justice and more recently the Spanish Supreme Court concluded that firing the Presidents of the Spanish regulatory commission for telecommunications (CMT) was illegal. Apart from concluding that the affected presidents should be compensated for the loss of income, the courts reflected concern about the independence of the regulator. (*El País*, 26 January, 2017, page 43).

[17] Prior to forming the government at the end of 2016, the Partido Popular (now the governing party) agreed with Ciudadanos (an opposition party) that the naming of Commissioners would be more independent than in the past. A group of experts would identify potential candidates, with the government choosing the Commissioners, subject to Parliamentary approval.

important role that the CNMC had.[18] This limiting of regulatory authority is consistent with the history of electricity sector regulation in Spain: the NRA acts as an advisor whose opinion is often required before legislation can be approved, but the government makes the final decisions.

The Spanish government is reported to be negotiating with the EC in order to avoid legal action on the matter of the CNMC's independence. However, it remains unclear whether the government is ready to give the final say on access tariffs to the CNMC[19]. In particular, the government will be very reluctant to give the CNMC authority to determine the levies used to recover the cost of public policies from different customer categories.

Within the limits of its authority, CNMC's primary goals are to promote effective competition, economic efficiency and market transparency in the interest of all the agents in the sector as well as consumers. Decarbonisation of the energy sector has introduced additional responsibilities for the regulator, especially related to the integration of renewables. The CNMC is now responsible for certification of origin for renewable energy and cogeneration output, for settlement of all cogeneration and renewable payments, and for inspections of all generation sites to ensure that information provided is accurate. Nevertheless, the CNMC's primary goals are unchanged.

This summary of Spain's regulatory institutions illustrates that the CNMC has limited independence from government and, more importantly, very limited authority to make decisions. It has, however, maintained its focus on economic efficiency, transparency and competition, while playing a supporting administrative role related to decarbonisation.

2.3.d Conclusions and recommendations

In the UK and Spain, the regulator's responsibility was originally to support effective competition and economic efficiency, on the understanding that this was in the best interest of consumers and provided a basis for investors to make efficient decisions. In the UK, Ofgem has been asked to take on new responsibilities related to decarbonisation and consumer protection that were probably inconsistent with its original remit. However, this seems now to have been remedied, with Ofgem once again able to focus on competition and economic efficiency.

In Spain, the independent regulatory agency acts mainly as an advisor to the government on key regulatory matters (for example tariffs), with the government taking all key decisions. Although the agency has new responsibilities related to the integration of renewable power, it continues to focus primarily on the promotion of competition, transparency, and economic efficiency.

The UK model of sectoral regulation has been widely recognized as best in class. Its reputation was threatened by the changes introduced to its remit and which were criticized by the CMA. While the details of the government's response to the CMA report are not available at the time of writing, the CMA's restatement of principles seems a valuable guide to the way forward.

Overall, the best outcome seems to depend on the context. In general, it helps to avoid conflicts of responsibility if the focus of the regulator remains narrowly economic. However, this may leave a gap in governance, namely the provision of expert advice for the government from an independent authority on decarbonisation policies for the energy sector. In the overall conclusions to this paper we argue that this gap is best filled by an intermediate body, along the lines of the UK Climate Change Committee, but with a specific focus on energy policy, to ensure that there is informed and expert input on the longer term consequences and system impacts of their decisions.

[18] CNMC 2015a, page 5. See also Cinco Dias article http://cincodias.com/cincodias/2016/09/29/empresas/1475169408_964733.html.

[19] 'Bruselas fuerza al Gobierno a ceder más competencias en energía a la CNMC', El País, 30 January, 2017, page. 39.

Section 3 – Costs, prices and burden-sharing

This section looks at the cost implications of the move to decarbonisation – how should the costs be kept under control? How far should the government intervene in prices to ensure that consumer acceptance of the process of decarbonisation can be sustained? Who should ultimately bear the costs – energy consumers or taxpayers?

3.1 Cost containment in meeting electricity decarbonisation targets

3.1. a Introduction

Because climate change is the biggest market failure of all timethere are inevitably cost implications when governments intervene to promote low carbon sources in electricity: if these were the cheapest options, at least in the short-term, markets would deliver them without the need for intervention. Governments are naturally concerned to contain these additional costs, in the interests of consumers, of industrial competitiveness, and of the economy as a whole. This section looks at the measures taken in the UK and Spain to contain the costs of meeting the low carbon electricity targets which the respective governments have adopted for their electricity sectors.

There are of course many aspects to the cost issue and this section focuses mainly on cost containment in relation to renewables targets. It does not look at the wider issue of whether it is sensible to have such targets in the first place – many economists would argue that an economy-wide carbon tax would be a more efficient way of meeting overall decarbonisation goals. However, in practice all EU countries have specific targets for renewable energy, and their main focus is electricity. This paper examines the comparative experience of the UK and Spain in relation to meeting their decarbonisation objectives in the electricity sector, rather than attempting to look at what they might have done had circumstances been different.

Similarly, this section does not look directly at distributional issues in detail, (although Section 3.3 does consider the scope for moving some of the costs to general taxation). There are many options for the allocation of the extra costs of decarbonisation – within the electricity sector the burden could be borne mainly by particular classes of consumer (for example residential customers as opposed to industrial users) or by particular categories of consumption (for example peak consumption only). More broadly, the costs could be spread across energy consumption more generally, or be borne by the general taxpayer. There are certainly good arguments, in terms of overall decarbonisation strategy, for a shift to a wider distribution of the costs (see for example OEF 2016), articles by Weale G and Johnson P) but they raise issues beyond the scope of this particular section.

Even in terms of the narrower remit of cost containment, there are many complications. Broadly speaking there are two ways of containing costs and two possible goals:

1) Creating incentives for efficiency in meeting a particular target, for example by introducing competitive auctions, as discussed below.
2) Setting a cap on overall costs, to ensure that these do not spiral out of control.

In the case of the first of these approaches, many questions arise – for example, is the aim to reduce the direct cost of meeting a particular target (say for wind power) or to reduce overall system costs? What are the trade-offs between short-term and long-term cost reduction? In the short run, in many countries, onshore wind power may be the cheapest option. However, in the long-term, other sources, like offshore wind and solar power may well be more attractive for economic or environmental reasons. Support for these sources, while expensive in the short-term, may well lead to learning effects and economies of scale which bring down long-term costs. The problem with such issues is that addressing them requires considerable levels of technical and economic expertise and a vision or plan for the long-term development of the industry – all attributes which governments are likely to have left behind at the time of liberalisation.

The second goal also raises problems. If a particular target (like the EU renewables target) is legally binding, presumably it has to be met whatever the cost – yet governments are understandably reluctant to sign blank cheques, whatever the importance of the goal. Arguably, their commitments

will carry more credibility if the government has clearly shown that the costs are manageable; this credibility will in turn reduce risk, and hence the cost of capital, so further mitigating the cost implications. However, this leaves open the question as to what happens if costs threaten to rise above the cap? Does it mean that budgetary considerations will override environmental goals, despite the fact that they are supposed to be legally binding? This section looks at the different ways in which the UK and Spain have approached these complex issues.

3.1.b UK

The UK has consistently put considerable stress on cost containment in relation to decarbonisation. This probably reflects its painful experience with its civil nuclear programme, which resulted in a catalogue of errors, cost overruns, project delays and under-performance (Taylor 2016). One study puts the total losses to the economy at some £32 billion in 2007 prices – much more than the economic losses from several other government projects, like Concorde and the Millennium Dome, put together (Myddleton 2007). One element of the programme, the Dungeness B reactor, has been described as 'the single most disastrous engineering project undertaken in Britain' (Henney 1994). The UK Treasury was strongly influenced by these failures, and one of the key aims of electricity liberalisation, from its point of view, was to shift project and investment risk on to the private sector, with the hope that such disasters, and the impact on the economy as a whole, would not be repeated. When decarbonisation rose to the top of the policy agenda, it was therefore concerned that the reintroduction of government-directed generation investment, via the renewables programme, might entail the same risks of cost escalation as the nuclear programme and it wanted to ensure that there was firm central control of costs.

It sought to achieve this by both routes described above. The first approach was via the arrangements for the support of renewable sources. These are discussed in more detail in Section 5.1. As described there, after a certain amount of experimentation with different approaches with the objective of finding the right balance between efficiency (keeping costs down) and effectiveness (getting as large a quantity of renewables built as possible), the UK has adopted a sort of hybrid approach in the form of Feed-in Tariff Contracts for Difference (FiT CfDs), which are now generally allocated by technology-specific auctions.

This new competitive approach has been very successful in bringing down prices. The UK Competition and Markets Authority estimated that the amount of support needed had come down by at least 25 per cent as a result of the introduction of auctions (CMA 2016, 54) and by even more as compared with some early projects. It recommended that competitive auctions should be the standard route for granting support and that any exception had to be clearly justified.

However, the reduction in the cost of specific support elements does not of itself set an overall cap on costs, as the Treasury required, and the buy-out price approach would no longer work within the FiT/CfD approach. Therefore as part of the overall package of electricity reforms the government introduced a new control, the Levy Control Framework (LCF) (OIES 2012, Lockwood 2016). The LCF sets a cap on certain low carbon policy costs every year, including renewable electricity support schemes. (These policy costs are in practice passed through to electricity consumers but they are treated in national accounts as a form of tax and spend. The aim of the LCF is to enable the Treasury to control the overall level of costs in the same way as other elements of public expenditure). The LCF cap is set for a number of years ahead and is designed to give some certainty and a clear framework for planning both for those holding the FiT CfD auctions (namely the Department of Energy and Climate Change) and for potential bidders. The size of the cost envelope has been fixed up to 2020, when it will reach around £8 billion in today's prices and it is expected to rise to around £11 billion by the mid-2020s. It includes 'headroom' to cater for unforeseen events but the overall aim is to keep costs within the cap; among other things, it requires specific Treasury approval for policies which threaten to lead to breaches of the cap.

At first, this aspect of UK policy seemed to be meeting with considerable success. The cap was set at a level which still seemed to allow for an expansion of renewables at a rate consistent with meeting carbon targets even after a number of changes to support schemes. UK schemes were also, in general, more stable than those in many other countries (see below) and the UK remained an attractive focus for renewables investment. Its track record was not perfect – in 2015, after the

elections, a number of changes were introduced, in particular dropping support for onshore wind and reductions in the level of support for solar photovoltaics; these changes dented investor confidence (HC 2016). Nonetheless, the Framework has, overall, been reasonably successful. It remains intact, despite the other changes introduced in 2015, and renewables development continues at a steady rate, so far at rather lower cost than in countries like Germany. There, the overall cost of renewables support has been running at over €20 billion a year, and substantial changes in support schemes were introduced in 2014.

However, there are reasons to believe that the Framework will come under more strain in future as a result of some specific design features:

- Firstly, the amount of support needed under FiT CfDs is determined by the difference between market prices and the strike price, as explained above. This means that if the market price falls, the amount of support goes up, so for the same amount of low carbon electricity, the government has to pay more. The market price has indeed been falling in recent years as a result of a combination of factors, including lower demand, falling gas prices and the impact of zero marginal cost renewables, so costs under the LCF have risen.
- Second, and perhaps perversely, the more successful the individual project (specifically the higher the output from the plant concerned) the higher the support payments implied under the FiT. In practice, the UK government underestimated how much electricity offshore wind would generate, because of a combination of the relative novelty of the resource and faster than expected technological improvement.
- Thirdly, in common with many other countries, the UK underestimated how fast solar PV would take off.

The result of all these factors is that at one stage forecasts for the overall cost of the LCF in 2020/21 looked as though they could reach £9.8 billion, well above the cap and even above the headroom provision. However, the forecast cost has since come down, partly as a result of the programme changes referred to above, and by November 2016 was close to target (OBR 2016).

However, the real test of the system may be yet to come in the form of nuclear power (which was in a way the starting point of the whole exercise, as noted above). While one nuclear contract (for a plant at Hinkley Point) has been signed, development has not yet started (and it is unclear at the time of writing whether it will actually go ahead). But the project is, in theory, just the first of a series of nuclear plants which are part of the UK decarbonisation programme (Taylor 2016). The problem with nuclear projects is that they are uncertain in their timing, and very 'lumpy' – that is, each project has a huge individual impact. For instance, the Hinkley project on its own would require around £500 million of support annually under the LCF if wholesale prices stay at around their present level. Its timing, and that of the other potential projects, remains highly uncertain, as does the impact on the LCF totals, making the idea that the LCF promotes certainty and predictability somewhat doubtful.

The government makes the case that the FiT CfD approach has been helpful in reducing the risks for UK consumers – EdF, the project developer for Hinkley Point, has spent some £2 billion to date on the project, despite the fact that no final investment decision has been taken. Neither these costs, nor any additional costs caused by any future construction delays or under-performance in its operation, will fall directly on consumers – they will only pay for what is actually delivered. So in one sense, the approach has been more effective than under the previous system of national ownership, when the costs of the Dungeness B power station were borne by consumers, probably without their knowledge.

But it would be difficult to argue that this is a case study in nuclear cost containment – the project was agreed without competitive tender, so goal 1 above has not been met. Nor is it clear, given that it has not yet been tested, whether goal 2 has been satisfied. In any event, the case could be made that the various risks mentioned in the previous paragraph have in effect been rolled up into the contract price, which is high. The Hinkley project has been described as 'the most expensive power station, and possibly the most expensive single constructed project, on the planet' (Taylor 2016).

At the time of writing, the UK's approach to cost containment can therefore be judged only a qualified success – on the one hand the introduction of competitive auctions has been successful in keeping costs down, on the other, the withdrawal of support for onshore wind (ruling out the option of the cheapest renewable resource) looks like the government shooting itself in the foot. The history of nuclear power is not encouraging, and experience with the LCF so far does not provide firm evidence as to whether the underlying contradictions arising from an overall cost cap have really been resolved. Some possible recommendations as to a way forward are discussed below.

3.1.c Spain

Spain's story is almost the opposite of the UK's, but in the end Spain adopted both of the cost control mechanisms: setting a cap on overall costs and creating incentives for efficiency to meet a particular renewables target.

Until about 2010, Spain witnessed rapid growth of investment in renewable power and of the costs associated with FIT/FIP regime. Spain was one of the early movers, one of the world leaders in installed capacity of wind power, solar PV and Concentrated Solar Power (CSP). However, governments were unwilling to pass the full costs of this policy decision and other public policies onto final consumers which has resulted in an accumulated 'tariff deficit' of over €25 billion[20]. This deficit is the difference between revenue collected through tariffs and the recognized cost of entitlements for regulated activities (including renewables, cogeneration, networks, domestic coal and support for the islands). Future consumers must repay that deficit, including interest, over the next 15-25 years. In short, until 2010, incentives for efficiency were largely missing and there was no real cap on overall costs, although tariffs were capped.

To stop the tariff deficit from growing further, governments from both parties introduced various cost containment measures, focused on capping and reducing costs associated with renewable energy and cogeneration as well as most other regulated activities, including distribution and transmission. The early measures included reducing the volume of renewable electricity that could earn FITs, eliminating premiums on top of the energy market price and introducing a moratorium on new renewable projects that could earn FITs. In 2013, the government introduced legislation that further reduced the regulated remuneration of existing renewable and cogeneration assets and of other regulated activities. While the measures introduced were successful in containing costs and eliminating the increase of the accumulated tariff deficit, they also contributed to a paralysis in new investment in renewables and triggered over thirty international arbitration proceedings (under the Energy Charter) by investors who are claiming economic damages related to the change in regulation.

The new regulatory regime for renewable power and cogeneration is based on the principle that renewable assets should earn a reasonable return on assets. It allows government to revise most of the criteria for assessing the support that investors receive – for instance the allowed return and the energy price forecast. This new approach applies to existing and new assets, and it introduces a risk associated with the revision of key determinants of profitability; it is therefore likely to raise the cost of capital that investors apply when assessing new investment.

The government has more recently begun to focus on the other form of cost containment, namely the introduction of incentives for efficiency in meeting government targets for renewables. In order to meet its 2020 renewables obligation, the government has adopted auctions. The first technology-specific auction was held in 2016 for 700 MW (500 MW of wind power and 200 MW of biomass), with bidders offering the 'incentive' (per MW) they required on top of the wholesale energy price. To the surprise and disappointment of many bidders, the result of the auction was no incentive at all. Various explanations have been given: following years of inactivity, a number of bidders had sunk investments and bid very aggressively; the amounts being auctioned were small; and the financial guarantees for meeting the investment commitments were low. However, it is also possible that the result was a reflection of the declining cost of renewables and the potential to recover fixed costs in the Spanish

[20] Energía y Sociedad 2013. The 'accumulated tariff deficit' refers to the sum of annual tariff deficits from soon after the year 2000. By the beginning of 2012, the estimated annual tariff deficit was over €10 billion.

wholesale energy market. We will soon know more because the government has announced an auction for 3 GW of renewable power in the first half of 2017. Most investors are expecting the result to be a positive incentive, because of the large quantity being auctioned and because the financial guarantees and conditions for meeting commitments will be stricter. However, the auction will be technology-neutral, encouraging competition to drive down bids[21]. Furthermore, given the prices resulting from auctions for wind and solar PV in Latin America, Africa and Asia, compared to current wholesale energy prices in Spain, there is good reason to expect a low incentive payment. Indeed, one cannot rule out a repeat of the last auction.

3.1.d Conclusion

These two cases studies suggest that cost containment measures have been a critical feature of decarbonisation programmes. In the UK, such measures were incorporated from the outset of the decarbonisation process; in Spain, they were introduced very late. In both cases, they involved efforts to limit costs through efficiency incentives, as well as through cost caps.

The UK concern with cost containment may have slowed the development of renewables, but this was something of a blessing in disguise, as the cost of renewables has fallen significantly. In Spain, renewables were developed at great speed, especially when solar renewable costs were very high;. As a result, cost containment came too late to avoid major financial difficulties and damage to the country's reputation in the investment community.

Efficiency incentives are now used in both countries, with competitive auctions preferred over approaches that set prices on an administrative basis. Both countries are moving towards more technological neutrality in auctions as a way of limiting costs. However, the UK has also found itself negotiating on a bilateral basis on nuclear power projects, an approach that poses serious problems for cost containment.

In one or both countries, cost containment also involves measures to cap costs, including: limits to the quantity of renewable energy or capacity that will be acquired through auctions; limits to the quantity of energy that can be sold under a FIT; annual financial limits of support schemes; and measures that will trigger reductions in revenues for renewable generators if profitability exceeds 'reasonable' limits.

A key element here is risk reduction. The cost of capital is critical for investment due to the high capital intensity of renewable and nuclear assets. The UK adopted the FiT policy with this in mind and it arguably lowered the cost of capital by comparison to the previous Renewables Obligation. On the other hand, in Spain, the change in the regulatory regime damaged the financial prospects of investors in existing assets, and this will have increased the perception of political risk related to Spain, at least initially. Investors are also concerned about the discretion that the Spanish government will have to change parameters and therefore returns on new investments.

Cost containment will continue to be a concern for all countries that are decarbonising their electricity sectors. Reducing risk is a key to containing costs, but so are competitive mechanisms, like technology neutral auctions, and legislation that directly limits total support costs. Perhaps the key message is to incorporate robust cost containment measures at the outset of the process – if they are introduced later on, they introduce risk and uncertainty, increasing the cost of capital and causing sudden booms and busts in investment.

[21] The design of this sort of auction will not be straightforward, in particular because the government wants the auction to be consistent with the remuneration scheme that is currently in place for renewables in Spain. This would make the Spanish auction different from other auctions, where bidders compete to sell a block of energy. Investors have been led to understand that the Spanish auction will focus on both energy cost and capacity cost, but they do not yet know all the details.

3.2 Price Intervention

3.2.a Introduction

One of the general principles of a liberalised electricity market is that prices for retail services and for generation are determined through the competitive process. Consumers buy from competing retail suppliers and have the right to switch suppliers, with retail prices being the result of this competition. Generators compete in wholesale markets, where short-term market prices will be set, and with expected market prices driving investment decisions. In practice, governments or regulators have intervened heavily in both retail and wholesale markets. This was true before decarbonisation became a key policy objective, but decarbonisation has increased the level of intervention and magnified its consequences.

Retail prices Even though the retail margin accounts for a small proportion (less than 5 per cent) of system costs, the retail price paid by final consumers reflects all of the electricity system's costs, especially those of generation and networks, in addition to taxes and levies. Governments occasionally intervene to influence the retail margin, to regulate final prices, to limit the structure of retail contracts in the competitive market, and to collect taxes and levies. Section 3.3 addresses the issue of taxes and levies (referred to as the 'government wedge'). In this section, we concentrate on the other forms of price intervention.

The original concept of liberalisation was about creating the conditions under which effective competition in retail markets would help to improve service quality, expand the range of services and avoid abusive retail pricing practices. Final retail prices established freely within the markets would reflect the competitive retail margin, as well as the cost of regulated activities (mainly networks) and prices in competitive wholesale markets. In the short run, consumers would participate actively in wholesale markets through their retail suppliers (or other aggregators), and their decisions would influence short-term prices and mitigate market power. In the long-term, consumer decisions in retail markets would influence investment in generation and networks. Through their revealed preferences, consumers would signal their willingness to pay for more or less security at different times, thereby influencing wholesale prices. Expected future prices would, in turn, drive investment decisions related to the choice of generation technology and the amount of network and generation capacity that was economically justified.

In practice, retail markets have rarely been left to work according to this model. There are at least three reasons for retail price intervention in a liberalised market. The first is that, initially, consumers had no way to signal their preferences with respect to how much they were willing to pay for electricity. For most consumers, there were no smart meters to register the time profile of consumption and so consumers paid a retail price that reflected an assumed demand profile. This barrier is related to the cost of smart metering, and is disappearing. Secondly, governments intervened directly through price regulation to favour certain consumer groups, either to deal with concerns about energy poverty or to achieve other political objectives, such as uniform national tariffs. Thirdly, regulators intervened because they were concerned about anti-competitive behaviour or because they thought this intervention would, ironically, make competition more effective.

The EU has generally supported full liberalisation of electricity markets and pointed to problems created by price intervention. In particular, maintaining regulated (last resort) tariffs for large numbers of consumers limits the potential to develop a more vibrant retail market, especially when these tariffs are set below prices that would be set by competitive retailers.

Decarbonisation and decentralisation of energy resources has increased the potential for prices to play an important role in the sector. Intervention in price setting distorts these price signals. For instance, with the support of new technologies, 'energy citizens' can now generate and store their own electricity and participate in a variety of electricity markets (for example, energy, capacity, ancillary services). If final prices do not reflect the level and the structure of the costs of supplying the consumers, they will not encourage efficient decisions. For instance, if consumers pay the same price when wholesale prices are low or zero (notably when renewables are meeting most of the demand) and when wholesale prices are high (such as when renewables are not operating), they will not shift their consumption to periods when prices and carbon emissions are lowest (although of course, as

discussed in Section 2, this depends on there being effective price signals from the wholesale market).

Price intervention is not always a bad policy. For instance, regulators aiming to encourage more efficient decisions by consumers have done so by establishing a tariff that passes on to them the hourly wholesale price. Additionally, regulators have intervened to promote the development of a retail market, for instance by setting tariffs high enough at the beginning of a liberalisation process so that consumers could benefit from leaving the tariff and entering into the competitive market space. There are other ways that regulators have intervened in ways they considered beneficial for the development of competition – however, if such interventions get embedded in the system, they are more likely to distort than to promote effective market competition.

Wholesale prices Many EU governments also intervene in the setting of wholesale market prices. Some do this directly by introducing price caps on the wholesale market price. Others do so indirectly by making payments to generators outside the energy market. Competition or regulatory authorities may also intervene if they suspect anticompetitive behaviour and the prospect of this sort of intervention can itself influence behaviour.

As with retail markets, price intervention in wholesale markets may be beneficial, but normally its effect is to distort them. Price caps in an energy-only market prevent prices from rising to levels that would enable cost recovery for generation capacity through that market. Intervention to support some generation assets through out-of-market payments involves 'pecuniary externalities' in the form of depressed wholesale prices that undermine further the recovery of fixed costs for the generation assets that do not receive out-of-market payments. Decarbonisation is the primary cause of these pecuniary externalities because of the payments made outside of that market for renewable energy.

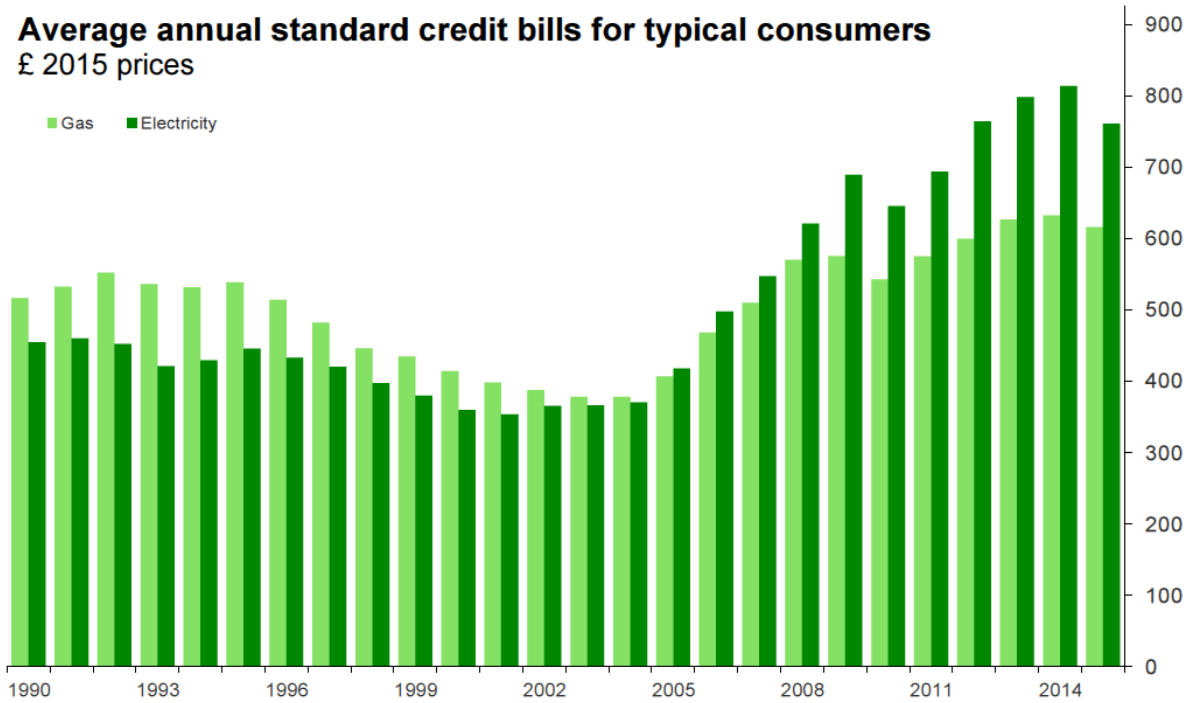
3.2.b UK

The UK moved away from the regulation of retail tariffs at an early stage – in 1999, full competition in electricity was introduced and all consumers were from then on able to shop around for their supplier while regulatory control of prices was removed. The hope was that allowing consumers to choose their supplier would keep downward pressure on prices, drive better customer service and promote innovation.

On the whole, the system worked well for the first decade or so, and prices remained relatively low in European terms. In practice, there was not very much innovation and no obvious sign of major improvements in customer service but whenever problems of this sort arose, the regulatory response was usually to press for increased competition and the removal of restrictions on switching suppliers (for example, shortening the time periods or restricting the use of 'bundled' products which tied consumers into long-term contracts). Ironically, this probably helped to inhibit innovation by focusing both customers and suppliers on a 'commodity' based approach looking solely at price per unit.

As long as electricity prices remained at acceptable levels this approach seemed to pay dividends and, as shown in Chart 7 below, for the first part of the 2000s electricity bills fell and remained below the level of household gas bills. However, from the mid 2000s electricity bills not only started going up but also began to outpace gas bills for average households. (There were a number of reasons for this rise, beyond the scope of this paper, but the costs of decarbonisation were certainly part of the picture).

Chart 7: UK residential energy prices



Source: House of Commons Library Briefing paper SN04153

This trend change (and the impact of recession) led to increasing concerns about fuel price levels and politicians and regulators were under pressure to take action.

They remained reluctant to intervene in electricity prices directly but sought instead to take further steps to improve competition and encourage switching. In 2008 Ofgem undertook an 'Energy Supply Probe' which identified barriers to consumer engagement such as the complexity of tariff options, the poor quality of information provided to consumers and low levels of trust in energy suppliers. But the problems remained and in 2010 Ofgem embarked on a Retail Market Review – apparently (as noted in the section on the role of the regulator) in response to political pressures. The solutions which Ofgem came up with – tariff simplification – also seemed to be political in origin. They included a limit on the number of tariffs which could be offered, the requirement for simpler tariff structures and presentation, and faster switching times.

Again, this was not enough to remove public concern and in 2014 Ofgem referred the issue to the Competition and Markets Authority (CMA) for a wide-ranging investigation into the UK energy market. The CMA made a number of recommendations but in relation to price intervention it distanced itself from the measures Ofgem had previously taken (and as noted in the regulation section, from the way these decisions had been made).

It said that the measures resulting from the Retail Market Review (RMR) had not worked to improve customer engagement, had restricted the behaviour of suppliers and inhibited innovation and had 'constrained the choices of customers in a way that may have distorted competition and reduced customer welfare'. (CMA 2016, 171) They commented that the discouragement of innovation was 'of particular concern over the longer term as RMR rules could potentially stifle innovation around smart meters'.

The CMA recommendations have largely been accepted by government and regulators – in effect, with the exception noted below, they appear largely to have returned to the original UK approach of avoiding intervention and relying instead on competition, seeing the RMR as a bit of an embarrassing blip. However, it is difficult to be sure how long the return to grace will last – as the graph above indicates, the increase in bills went into reverse in 2014, just as the CMA investigation got under way. As prices start to rise again (partly as a result of decarbonisation measures) pressures for intervention

are re-emerging: a price cap has been imposed, for the first time since price liberalisation, on tariffs for prepayment customers (who the CMA argued were not being served well by markets). Additionally, announcements of electricity price rises by a number of companies in February 2017 have led to calls for greater controls over retail pricing.

As far as wholesale markets are concerned, there has been a history of concern about market dominance and anti-competitive behaviour, which resulted in the break-up of the big UK generators. More recently, the concern has focused on decarbonisation and the need for market reform to integrate new low carbon sources – these issues are discussed briefly in Section 2.

3.2.c Spain

Intervention in the Spanish retail market has been direct. It consisted mainly of establishing a regulated retail tariff, or a regulated retail tariff formula, for small consumers, as well as setting access tariffs for all consumers. For many years, the government relied on a centrally managed quarterly auction through which certain retail companies purchased electricity to supply their consumers who were contracted under a regulated last resort tariff. To this wholesale price, the government added a variety of regulated costs, including costs for retail service, networks and levies to finance public policies. The auction had the political appeal of being a market mechanism for determining the wholesale cost of electricity to include in the final tariff, encouraging lower prices through competition and allowing the state to minimise consumer dissatisfaction with the government if prices rose. However, eventually this approach became politically inconvenient when the CESUR price spiked substantially at the end of 2013. At that point, it was replaced.

The new approach is based on a regulated formula called the PVPC (variable price for small consumers) that passes on short-term wholesale price signals to small consumers and which comprises both a fixed and a variable component. There are three important features of the PVPC. The first is that all consumers with contracted capacity below 10 kW are entitled to buy on the basis of this formula, but are free to seek alternatives in the competitive retail market. A key reason to move away from the PVPC is to obtain contracts with guaranteed prices, thereby shifting the risk of wholesale price volatility to the retail company (which charges the consumer accordingly). The second feature is that the variable element of the PVPC changes on an hourly basis to reflect the hourly wholesale cost of energy. For consumers with a smart meter[22] that is integrated into the billing system, the PVPC provides economic incentives for the consumer to alter consumption patterns, either directly (for example, deciding when to run their washing machines) or eventually through aggregators or digital devices that could be programmed to minimise costs. For consumers without a smart meter, the hourly energy cost component is based on an assumed demand profile. The third point is that retail companies argue that the retail margin built into the PVPC is inadequate to cover the cost of retail services and, consequently, offers a subsidy that discourages consumers from entering the liberalised market.

A second form of price intervention is the inclusion of levies in access tariffs; these levies are additional to the regulated cost of networks included in the access tariffs and to recognized taxes (VAT and the special electricity tax). The levies cover the costs of many different public policies, including support for renewables and cogeneration, the financing of the tariff deficit and the costs of supporting different consumer groups. These levies can increase final prices by up to 30 per cent, before VAT and other tax.

A third form of price intervention is related to very large industrial consumers who are paid to provide interruptible services. These are discussed later in the paper, but suffice it to say here that these payments may constitute a form of subsidy to large industrial consumers.

Finally, in relation to wholesale markets, the most significant source of intervention of relevance to this paper is related to administrative capacity payments for conventional generators and financial support for renewable energy and cogeneration through out-of-market payments. These payments increase

[22] Spain has a plan to install smart meters for most consumers by 2018; by the end of 2016, 70 per cent of these meters had been installed.

generation capacity and tend to depress prices. In particular, feed-in tariffs for renewable energy and cogeneration have introduced a dual price effect: very low wholesale prices when hydro and wind plants are operating fully and at the margin, with much higher prices when hydro and wind conditions are poor, when coal or natural gas fired plants are at marginal supplier.

3.2.d Conclusion

Price intervention can have positive and negative features. On the positive side, for instance, in Spain the PVPC arguably provides more effective price signals for consumers (at least those with smart meters) than in most EU countries, which tend to rely on standard kWh prices. However, there is a risk that intervention to meet consumer concerns by simplifying tariffs, as in the UK, will have the effect of inhibiting innovation. Similarly interventions in wholesale prices may well have the effect of distorting markets and preventing them from giving accurate signals to consumers and investors. It is beyond the scope of this paper to look at the wider problems of wholesale market design (for which see OIES 2016a) but a preliminary conclusion might be that the government and regulator should avoid intervening in price levels or the flexibility of suppliers to offer different options to consumers. In addition, they do have a responsibility to ensure that the underlying market signals are undistorted, because it is governments themselves which are in effect introducing the market distortions via their support for low carbon sources. Unless they can find ways of dealing with the 'pecuniary externalities' this entails, there is no prospect of arriving at self-sustaining low carbon electricity markets which can fulfil the role described in the introduction to this sub-section.

3.3 The 'government wedge'

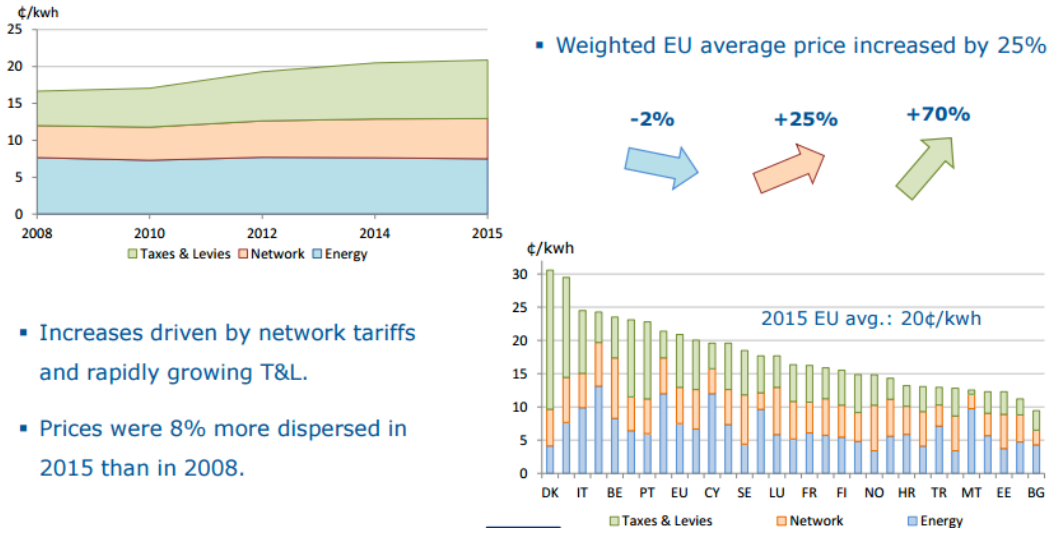
3.3.a Introduction

One of the consequences of decarbonisation is the need to finance it. As indicated above, in most cases, low carbon alternatives to fossil fuel generation are relatively expensive, highly capital intensive and unlikely to recover investment costs in today's energy markets. Furthermore, to integrate intermittent renewables and support consumer participation in markets requires investment in smart networks and metering as well as backup capacity. We discuss in other sections how some of these costs can be remunerated through new market mechanisms, such as capacity markets. But eventually, the question is how to finance all of these additional costs related to decarbonisation.

There are basically two models for recovering the extra costs: including them in electricity prices or recovering them through the general taxation system (although, as noted above, there are many variations on both themes). The former is the standard approach in the EU, whereas in Canada and the US this approach is combined with greater reliance on general taxation.

The EU has a methodology for comparing electricity prices among member states. It identifies three components to price: the cost of energy (wholesale electricity prices plus the retail margin), the cost of networks (transmission and distribution), plus taxes and levies. As reported recently by the EU in Chart 8, taxes and levies in residential prices have risen substantially (by 70 per cent) since 2008 and account for most of the 25 per cent increase in average final prices. In many cases, these levies are hidden in the reporting categories for energy and network costs and an element of detective work is required in order to estimate the taxes and levies component.

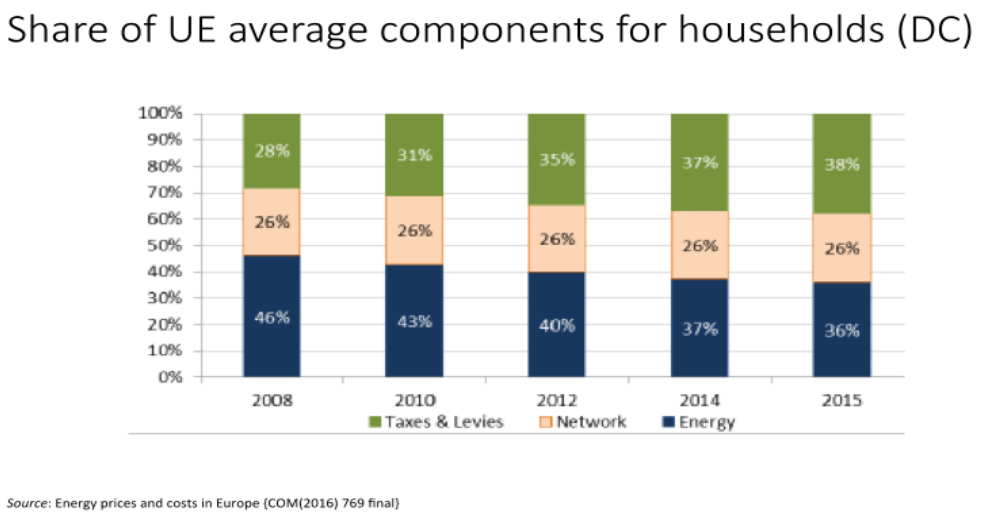
Chart 8: Evolution of the electricity price for households in the EU, 2008-2015 (€ cents/kWh)



Source: Magyar 2016

The result, reflected in Chart 9, is that energy costs accounted for about 36 per cent of the average electricity price in 2015, compared to 46 per cent in 2008. Network costs remained constant at 26 per cent over the period, while taxes and levies rose from 28 per cent to 38 per cent. As mentioned earlier, these percentages in 2015 apply to a much higher average price.

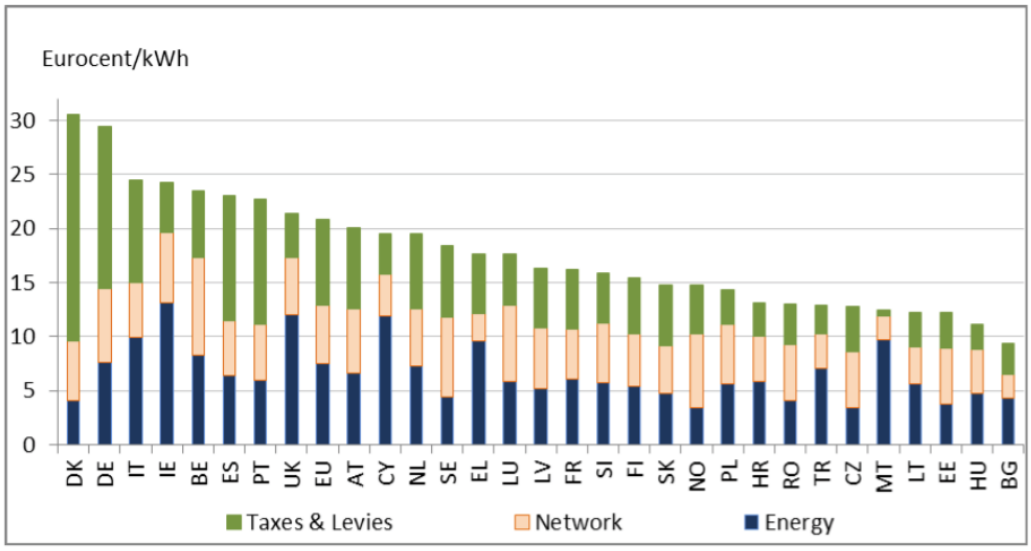
Chart 9: Electricity price components for EU households



Source: European Commission 2016

Incorporating these costs into electricity prices is sometimes, but not always, done transparently. Germany is an example of the relatively transparent approach; Spain's approach is less transparent, as explained later in this section, with the UK somewhat in between. The EU's recent study on energy prices and costs was to reveal the extent of taxes and levies in different EU countries, using a common methodology. It is evident that Denmark, Germany, Spain and Portugal have the largest government wedges of all the EU countries.

Chart 10: EU electricity price components by country in 2015 for households



Source: European Commission, Member States

Source: European Commission 2016, page 36.

There is steadily increasing pressure in the EU to share the costs of renewable energy subsidies more widely. For instance, France has recently decided that these costs should be shared between electricity and other energies, and Germany is also contemplating this. A similar debate is underway in Spain, where proposals include sharing these costs among all energies, and recovering some costs through general taxation.

3.3.b UK

The UK approach to the policy wedge is relatively transparent. In line with EU standard accounting rules, the extra cost of support for renewables and some other government schemes is included in the national accounts as 'tax and spend' even though in practice such costs are passed directly on to consumers via the electricity price.

More specifically, as explained in Section 3.1, under the Levy Control Framework the total cost of a number of government policies is publicly identified and capped. The costs concerned (for example the Renewable Obligation (RO)) are in fact borne in the first place by energy companies and then passed on to consumers, without going through the public exchequer. However, because they are mandated by the government, they are classified by the Office of National Statistics as taxes and the money that is spent on them as public expenditure. For example, the RO involves placing an obligation on energy suppliers to pay a premium to renewables generation which is classified as public expenditure. The cost of the RO, which is passed through to energy consumers, is classified as a tax, since the transfers are compulsory and not a direct payment for a good or service. The tax and spend generally net to zero automatically, so there are no implications for public borrowing.

However, there are limits to the UK's transparency:

- The first is that the extra costs do not appear transparently on consumer bills. Although in theory everyone knows the total cost of the support, because it appears in public accounts, consumers are often very unclear about how large a component of their bills is due to decarbonisation. Indeed, with the recent increases in prices in the UK discussed above (Section 3.2) this has often been a topic of contention.
- More fundamentally, the costs concerned are only the readily identifiable costs of specific government schemes, rather than the overall costs of decarbonisation. For instance, there are further levies (the Energy Company Obligation and Warm Home Discount) which will also affect

bills. There are costs associated with the low carbon transition and in particular the extra transmission costs associated with the connection of renewable sources to the system, costs which are not part of the Levy Control Framework. These costs run into billions – they represent around one third of the total investment required in the UK electricity system up to 2020. Then there are the extra costs of system balancing, capacity and ancillary payments and so on, which are also significant additions and which are to some extent related to decarbonisation.

There are ways of identifying the wider costs described above, but it would have to be done on a whole system basis (specifically by looking at the total costs of a system, including transmission and other network costs, ancillary costs and so on) on a policy scenario as compared with a business as usual scenario. But this would entail enormous complications and contentious assumptions and the government has sought to avoid the issue, for instance arguing that the extra transmission costs cannot readily be identified.

In a wider sense, the government has also seemed keener to obscure than to reveal the overall costs. For instance, it argued that the CfD approach (discussed in Section 5) would be a clear benefit to consumers by shielding them from the impacts of fossil fuel price volatility. It was only pointed out in the small print that a FiT CfD effectively commits consumers to decarbonisation by establishing an implicit contract with generators whereby consumers, in order to meet these targets, forsake the opportunity of low bills in the future if gas prices are low. Similarly, the government has argued that in the long term its Electricity Market Reforms would save consumers money (because of an expected rise in gas prices which has not so far taken place, and as a result of its energy efficiency programmes, which – as discussed in OIES 2011 – it makes no serious attempt to measure in practice).

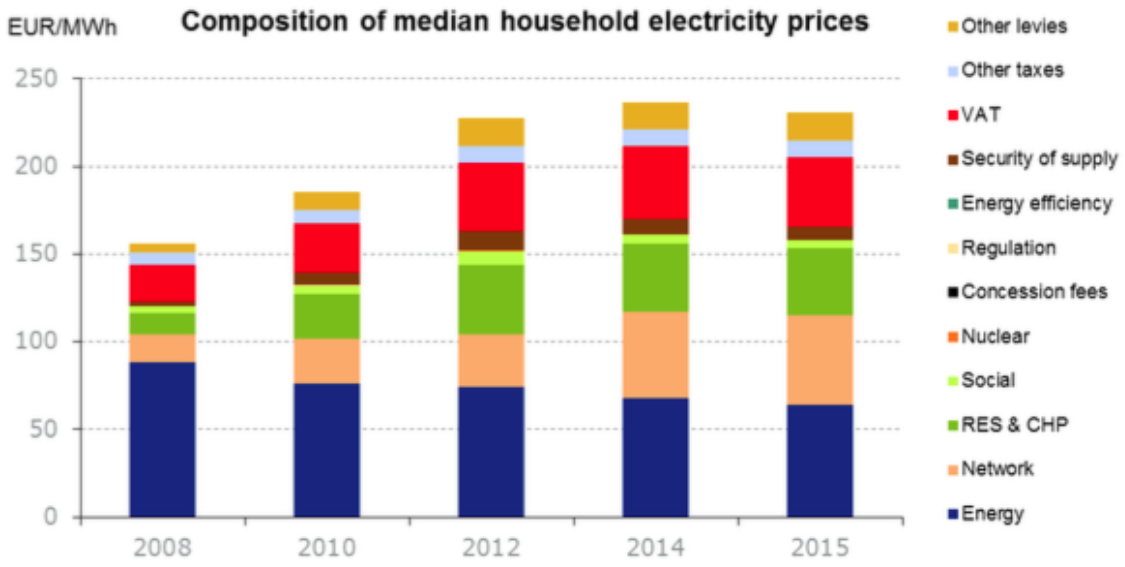
3.3.c Spain

In Spain, governments have recovered most of the extra costs of decarbonisation (and other public policies) by raising electricity tariffs. For instance, final electricity prices for residential consumers rose by over 50 per cent between 2008 and 2014[23]. The government wedge explains over 70 per cent of the increase and in 2014 it accounted for 46 per cent of the final price for these customers. VAT is the most important component of the wedge for residential consumers. Then comes the financial support for renewable electricity and cogeneration, interest payments on the €25 billion tariff deficit, and other regulated activities and subsidies. The interest payments on the tariff deficit are a reminder that, although Spain did not immediately pass on all the extra costs related to decarbonisation through final tariffs, in time these costs will be recovered through tariffs paid by future consumers.

It is not straightforward to determine exactly the size of the hidden levies in Spain's electricity prices. However, a recent EU study on energy prices and costs reveals the extent to which taxes and levies have increased in Spain, compared to the cost of energy and networks. The results are summarized in Chart 11. The cost of energy (the dark blue bar) has fallen since 2008, and the cost of networks (the beige bar) has risen, with the combination of these two system costs rising a little over the period 2008-2015. Meanwhile, levies and taxes have grown very substantially and constituted more than 50 per cent of the average price in 2015, with renewables and cogeneration (RES and CHP) the largest levy.

[23] Robinson 2015, p. 9.

Chart 11: Electricity price composition for households in Spain: 2008-2012



Source: European Commission 2016, page 450.

3.3.d Conclusions and Recommendations

There are some good reasons to charge consumers a higher price to reflect the costs of decarbonisation. Efficiency requires that consumers should pay the long run marginal cost of a low carbon energy system, which may be more expensive than the old system. Furthermore, higher prices encourage conservation and more efficient use of energy. In addition, Ramsey pricing theory suggests that it is efficient to tax the most inelastic demand, traditionally electricity. More fundamentally, governments have been able to use electricity as a means of tax collection because consumers had little choice but to pay.

However, there are some serious problems with setting prices for electricity that are higher than the long run costs of a low carbon system. Firstly, there are obvious concerns about the distributional impact on the poorest households and about the impact on competitiveness of industry and commerce. It is also now increasingly feasible for consumers to bypass the taxes and levies through own-generation or in other ways. However, the main problem is that the growing government wedge in the electricity price discourages effective competition between (increasingly decarbonised) electricity and fossil fuels in end markets, like transport and heating. Most policy makers and experts expect low carbon electricity to replace fossil fuels in these markets through the process of 'electrification'. Raising the price of electricity to finance renewable energy and other public policies gets in the way of this process and more generally distorts competition among energy vectors.

Optimal taxation theory aims to minimise distortions in the economy while collecting sufficient revenue to cover expenditure. Furthermore, climate change is a very particular challenge. Arguably it is not best treated as an externality in the normal way (which theory suggests can be dealt with essentially by incorporating the externality in prices). Climate change is different – in particular, the costs and benefits do not flow primarily to present consumers in Europe but to future residents of countries outside Europe. In many ways it has the characteristics of a global public good, rather than a simple externality.

There are therefore good general arguments for financing climate change, like other public goods, through general taxation (VAT, income tax and so on) or by spreading these costs among competing energy products, rather than by raising the price of a single product in a competitive energy market.[24]

[24] Newbery, *Reforming UK energy policy to live within its means*, Cambridge Working Papers in Economics, September 14, 2015)

In this specific case, fighting climate change through the promotion of renewable power would constitute a public good and would justify financing the additional costs of supporting renewables through the budget. This would allow for more effective competition among energy vectors and help to lower the cost of decarbonising the economy. So far, however, neither the UK nor Spain has made much progress in this direction.

Section 4 – Network regulation

Electricity networks have always been regulated in line with the basic theory of unbundling – that electricity supply can be divided into different components. On the one hand there are the competitive elements of generation, which can be left to the market (in practice, as noted in Section 3, this goal has not always been met). On the other hand, there are the transmission and distribution functions – the networks, regarded as natural monopolies in a technical sense (because they show economies of scale at every level) and in the more straightforward sense that it is not worth building competing networks, for economic and environmental reasons. These parts of the industry should therefore be regulated in the same way as any other natural monopoly.

Decarbonisation puts this simplistic assumption into question, for two main reasons:

- First, the functions of the networks will change significantly (though in ways which remain uncertain) as a result of the penetration of new energy sources. One of the key imperatives will be to encourage flexibility and innovation – not the traditional aims of monopoly regulation.
- Second, it has always been the case that in electricity networks, generation and network expansion can sometimes be alternatives, namely effectively in competition with each other. If they are regulated differently, this distorts the playing field for competition. But while in the past this problem has been relatively marginal and largely manageable, in future it will be one of the central challenges of a decarbonised system. Treating networks as a separate entity will no longer be an adequate approach.

The sections below look at some of the implications of these changes – for the role of networks and distribution companies, for interconnectors between systems, and for network pricing.

4.1 Role of networks and distribution companies

4.1.a Introduction

Traditionally, the role of the electricity distribution company was straightforward – as the term suggests, it was simply to distribute electricity to consumers. The electricity was mainly generated elsewhere, by large central power stations, and delivered to the distribution companies via the transmission system, which was, in most cases, managed by a single transmission system operator (TSO) or, alternatively the generation and transmission functions could be combined, as was often the case. Consumers were regarded as essentially passive – the job of the distribution company was to create and manage enough local network capacity to ensure that the power from the transmission system could be provided to final consumers as and when it was needed. Regulation was also straightforward – these were classic utilities, subject to rate of return or price cap regulation, normally implemented so as to pay a fixed amount for each unit (kWh) distributed. With steadily growing demand and monopoly control of the network, distribution companies had secure long-term revenues and a low cost of capital.

All that has changed in the new era:

- Generation is no longer exclusively centralised. In the past there might be a few tens, or at the most hundreds, of generators, nearly all connected to the transmission system. Now, because of the growth of renewable sources, and in particular solar photovoltaics, generators exporting to the electricity system number in the hundreds of thousands or millions (over 750,000 in the UK, for example) and the vast majority are connected to the distribution system.
- Power flows have changed as a result. In many parts of Europe (for instance in the South West of the UK), there is an excess of generation in the distribution system when the weather is sunny: power flows ‘in reverse’ up to the transmission system. Distribution is no longer simply a one-way conduit.

- The role of demand has also changed fundamentally. Demand response is seen as a central part of any future system, but the new era means that electricity users will no longer be passive consumers but active participants in the management of the system and the maintenance of overall balance. (This is discussed in a separate section of this paper but it also has implications for the operation of the distribution system, as discussed here).

These changes have profound implications for the nature of the distribution function and for regulation. For instance:

- Can revenues continue to be based on throughput? With the growth in on-site generation, distribution system throughput in many areas is declining (leading to lower revenues for the system, and hence to higher prices per unit distributed, reinforcing the incentives for on-site generation – the so-called 'death spiral').
- Can distribution companies continue to be regarded as simply 'network operators'? At the very least they may have to take on a more active function in terms of system operation: forecasting and managing system flows at the local level, possibly contracting and despatching distributed energy resources. At present the role of distribution system operators (DSOs) has been described – by the regulators' body itself – as 'broadly passive' (CEER 2015) but this is bound to change over time.
- In the longer term, the role of the distributor may need to develop even further. A possible future is one based on microgrids, under which local entities like universities or zero carbon housing estates may aim to be largely self-sufficient, distributing electricity themselves within their own networks and interacting with the public distribution grid only for purposes of balancing and trading.

In the longer term, distribution companies may therefore have to take on the role of facilitator and platform provider rather than simply that of network operator.

In New York State in the US, under their Reforming the Energy Vision (REV) initiative, this new role has been articulated as that of 'distribution system platform provider' (DSP) whose function is to create:

> 'an intelligent network platform that will provide safe, reliable and efficient electric services by integrating diverse resources to meet customers' and society's evolving needs. The DSP fosters broad market activity by enabling active customer and third party engagement that is aligned with the wholesale market and bulk power system'. (NY 2015)

If this is to be their future role, many traditional assumptions may no longer be valid. For instance, it is entirely feasible to contemplate competing platform providers, as in other industries, so that traditional forms of monopoly regulation as such may no longer be appropriate. Perhaps the main message at this stage is that, while the overall trend is clear, the final destination remains uncertain. One key role for the regulator in these circumstances is to avoid distorting the process of evolution and to create maximum flexibility. This may require novel approaches, such as negotiation of the regulatory regime between distribution companies (or platform providers) and the regulator, or differences in approach between regions according to the specific circumstances and stages of development. This section looks at how the UK and Spain have responded to these 'new era' challenges.

4.1.b UK

The UK was relatively early in recognising and responding to the challenges. In 2007 it embarked on a process of long-term scenario planning known as LENS (Long Term Electricity Network Scenarios). The objective was to 'facilitate the development of plausible electricity network scenarios for Great Britain for 2050, around which industry participants, Government, Ofgem and other stakeholders can discuss longer term network issues'. It identified a number of possible scenarios, with different implications, including:

- Big Transmission and Distribution – basically a straightforward evolution of business as usual, in which TSOs remain at the centre of network activity.
- Energy Service Companies (ESCOs) – where energy service companies act as agents for consumers, and networks contract with the companies for the provision of network services.
- Distribution System Operators (DSOs) – in which DSOs take on the central role in the electricity system including generation and demand management, quality and security of supply and system reliability.
- Microgrids – where self-sufficiency is the watchword and microgrid system operators provide system management services for active groups of consumers.
- Multi-purpose Networks – which contain features of most of the scenarios above. TSOs would still have the central role in developing and managing networks but distribution companies would also have a significant role and the dominant theme would be diversity of approaches.

Ofgem considered the implications of these scenarios for its work and its main conclusions were that:

- There is a relatively high degree of uncertainty.
- Regulatory policy will need to be flexible and adaptable.
- There is value in keeping options open.
- The different scenarios have different implications for the roles and responsibilities of particular actors.
- Ofgem, as regulator, might need to develop new regulatory tools, for instance policies to encourage innovation. (Ofgem 2009a)

In line with these cautious but forward-looking conclusions, Ofgem has introduced a new regulatory approach, known as RIIO (Revenue = Incentives + Innovation + Outputs), designed as a performance-based model with the broad aims of providing incentives for network operators to:

- Put stakeholders at the heart of their decision-making process.
- Invest efficiently to ensure continued safe and reliable services.
- Innovate to reduce network costs for current and future consumers.
- Play a full role in delivering a low carbon economy and wider environmental objectives.

The approach is much more open-ended than traditional regulation, with companies being asked to submit business plans consistent with an overall framework set by Ofgem, to be developed with strong stakeholder input. Ofgem then reviews the plans to determine what 'levels of scrutiny' it needs to apply. Some may be fast-tracked to early implementation, while others may need to be revised and resubmitted.

The plans (and company revenues) are based to a large extent on output measures in areas such as reliability, customer satisfaction and speed of connection, and are designed to give incentives for efficient and effective delivery of these outputs. There are also specific provisions to encourage innovation, including a 'Network Innovation Competition' and various innovation allowances and mechanisms which allow companies to secure additional funding to roll out proven innovations.

Given the flexible nature of the system and its novelty (it was first introduced in 2013), it is too early to judge its overall effectiveness. One assessment suggested that it had made:

- Some progress but less than elsewhere, in making more use of negotiation.
- Limited progress in increasing competition.
- Gone some way to incentivise responsiveness and fund innovation.
- No progress in further unbundling (Pollitt 2014)

Another study suggested that change remained 'marginal' at the level of network operation and planning and that network operators still had a basic interest in network growth (Lockwood 2014). In

other words, the general reaction seems to be that the UK is heading in the right direction but has not yet gone very far down that road.

The same might be said of the move towards changing the role of the network operator to that of distribution system operator. The general goal is clear – that DNOs will have to change over time into fully fledged and active DSOs, and take on some of the functions described below. Ofgem is currently examining what would be involved in this process and what the timescale might be. In late 2015 Ofgem called for the debate to be revitalised and for distribution companies to become more involved, perhaps indicating a relatively low level of enthusiasm for the exercise.

The problem is that it will require the development of new capabilities, described by one network operator as including the following:

- Understanding historic and real time energy flows
- Forecasting future energy volumes to highlight opportunities for flexibility
- Actively reconfiguring the system in response to need
- Contracting/despatching Distributed Energy Resources
- Coordinating DSO operations with the UK System Operator
- Maintaining a platform for energy suppliers, communities and other market participants. (WPD 2016)

Much of this is new for the distribution operator and many of the projects being proposed under the 'Network Innovation Competition' arrangements described above are designed to provide the necessary experience and information to underpin such roles. For instance, the projects include creating 'an open intelligence platform', designing and demonstrating a 'network information model' and assessing 'the viability of using embedded third party assets, such as storage or generation, to improve security of supply, avoid reinforcement and minimise the use of mobile generators when faults occur on the network.' (Ofgem 2016) In other words, we are at a relatively early stage of developing the capabilities and skills needed for the fully developed system operator role, much less the wider platform and facilitator functions discussed above.

Overall, the UK approach seems (typically) cautious and pragmatic, being as much about learning and exploring ways through the uncertainties as about setting a definitive course and on the face of it, a very different approach from the Energy Vision referred to above.

4.1.c Spain

Regulation of distribution in Spain has not yet developed to adapt to the new challenges of decarbonisation. The electricity distribution business has only recently been subject to a fairly traditional form of rate of return regulation, and there have been no formal proposals along the lines of RIIO or the NY Rev.

The remuneration of distribution (and of transmission) fell as a result of the government's efforts to eliminate future tariff deficits. As described in Section 3.3, the annual tariff deficit reflects the difference in cost of regulatory entitlements and the tariffs collected to pay for the regulated activities. Regulatory entitlements include remuneration for distribution and transmission activities, as well as for renewable energy, cogeneration and many other activities and costs. Legislation to eliminate future tariff deficits included reducing most of the regulatory entitlements, including the total remuneration for distribution.

The new regulation for distribution begins with a physical inventory of assets, which are valued on a replacement basis, except for the low voltage networks, where the regulator uses a reference network adjusted by a coefficient. The distributor is entitled to recovery of the RAB (Regulatory Asset Base), including a regulated return. The regulator determines the RAB based upon the residual life of the assets, thus excluding assets already amortised, and remuneration is payable from 1 January of the second year after commissioning. The OPEX is calculated by reference standard values. The remuneration is also to be linked to the general inflation rate less constant taxes, non-processed foodstuffs and energy (rather than the general inflation rate).

The regulated remuneration for distribution[25] is:

- fixed for six-year periods;
- determined on the basis of a well-run and efficient undertaking, pursuant to formulae attached in the legislation;
- considered a low risk activity and remunerated at the ten-year bond rate plus a 200 basis points (2 per cent) margin; and
- cannot exceed more than 0.12 per cent of the GNP forecast. Distribution companies will be asked to respect and abide by their annual and three-year investment plans.

The central message is that the regulation of distribution activities in Spain has changed more in response to concerns about the tariff deficit, than in order to meet the challenges of decarbonisation. Spain certainly has kept its options open, but has done little so far to consider the options in a way that the UK has done.

4.1.d Conclusion

The way forward in this area remains unclear and for good reason. The uncertainties are too great for an over-prescriptive approach to work. Tentative steps forward, incorporating the maximum degree of flexibility, along with encouragement for innovation, seem to be the sensible course. The problem is that this is far outside the traditional roles of regulators themselves, or of distribution companies – they will increasingly be operating well beyond their comfort zones. Despite their discomfort, this seems inevitable. There is a wide range of future possible scenarios for networks and distribution companies. If regulators (and companies) decide prematurely on any particular model, this is likely to distort evolution towards an efficient low carbon system. So far the UK seems to have developed its thinking in this area further, but this only serves to underline the uncertainties. There is no single vision for the future role of networks in the UK but the encouragement given by the regulatory system to experimentation and innovation seems a better way forward than traditional approaches to regulation. Spain has, by contrast, done little to prepare the regulation of distribution for the new era.

4.2 Interconnectors

4.2.a Introduction

Interconnectors (for the purposes of this section defined as electrical connections between different national networks) have always raised complex issues for regulators and policy makers. At first sight interconnectors are simply a particular version of electricity transmission, comparable with connections between different regions of the same country, and can thus be handled within the framework of network regulation more generally. In practice, however, as explained below, interconnectors tend to create special, and often highly political, problems which need to be addressed in their own right. The new era challenges discussed in this paper have added significantly to these complications.

On the one hand, there are strong arguments for encouraging such interconnections and the growth of renewables further reinforces those arguments. Interconnections are obviously important for the development of the European Single Market in electricity. The more the European network approaches the ‘copper plate’ ideal (namely a system in which electricity flows equally easily between any two points in the network) the better the market will operate, the greater the efficiencies which can be realised, and the easier it is to deliver electricity security. Interconnection capacity is still well below the optimum level for this purpose – national systems grew up separately and for many decades interconnections were treated as an afterthought, mainly designed to provide alternative supplies in situations of national shortage. The EU has therefore long had the goal of increasing interconnections – a target of 10 per cent of generating capacity for each country by 2020 was agreed in 2002 and in 2014 this was supplemented by the goal of 15 per cent by 2030 (Buchan and Keay 2016). Nonetheless, as noted in the introduction to this paper, many countries, like the UK and Spain, remain

[25] Uría Menéndez 2013 Pages 8-9.

well below this level (at 6 per cent and 3 per cent respectively in 2014) for geographical and historical reasons[26].

The market, security, and efficiency arguments for interconnections have been reinforced by the new imperative of decarbonisation. Renewable sources are site specific so higher degrees of interconnection give greater access to alternative and more reliable resources and lower cost generation sites. For example, the solar resource in southern Europe is much superior to the resource in countries like the UK and Germany, which have seen such rapid growth in solar PV in recent years. Similarly, as noted in the general introduction, the UK and Spain have limited access to Europe's hydro resources. A link between Norway or Iceland and the UK could contribute substantially to security in a low carbon system.

There are also strong economic arguments: the cost of decarbonisation could be brought down significantly if Europe focused on the most cost-effective resources across the Continent (for example Green and Strbac estimate potential savings of €19 billion a year from a more rational deployment of renewables – OEF 2016). In addition, the larger the area covered, the easier it is to cope with the costs of intermittency: while similar weather conditions sometimes affect large parts of Europe, the wider the geographical coverage, the less likely it is that all regions within it will be affected to the same extent. (Indeed, some decades ago the visionary Buckminster Fuller extended this concept to a global level, envisaging the possibility that solar power in Asia could be sold to, say, Europe via a global energy grid.)[27]

So the arguments in favour of promoting interconnections are stronger than ever in a world committed to decarbonisation. But the obstacles remain manifold. They arise in many areas:

- **Regulation** Regulation of electricity transmission and distribution developed at a national level and was generally designed to encourage the development of a fully integrated national network, one that approached as far as possible the 'copper plate' ideal. Regulators rarely had international trade or a European 'copper plate' as their objective and their systems were not well equipped to deal with investment in interconnectors on a level playing field with national projects.
- **Distributional effects** Regulators' problems were compounded by the fact that the construction of interconnectors has distributional effects. Broadly speaking, when an interconnector is built between a high-priced system and a low priced system (which is what would create the market justification for its construction) it tends to lead to price convergence: consumers in the low price state will suffer higher prices, while generators there will benefit from them. The reverse effect will apply in the high price state. The outcome may well be higher welfare across the integrated region as a whole, but regulators in individual states may be more concerned about (or required by their statutory duties to think only of) the effects on their consumers or generators. They may find it difficult to be sympathetic to proposals for investment in interconnectors for that reason.
- **Environmental impacts** Somewhat similar arguments apply to the environmental impacts, which can be considerable (for example interconnectors between Spain and France have to pass through the environmentally sensitive Pyrenees region). From a public perspective it can be difficult to justify environmental damage when there is no proportionate benefit at national level.
- **Risk** Interconnectors entail a high degree of risk, particularly when they link different regulatory regimes. There can be political risks relating to construction and pricing, uncertainty about whether power will actually be allowed to flow during an emergency, and the risk that the original market justification may be superseded by price or market changes in the markets being connected. Clearly such risks are less within a region, such as the EU, which has a history of

[26] It could be argued that the appropriate way to measure interconnector capacity should be by reference to peak demand rather than total generating capacity (including intermittent renewables).

[27] (http://www.geni.org/globalenergy/library/newsletters/1995/buckminster-fuller-on-the-global-energy-grid.shtml). A slightly less visionary, but still very ambitious, version of a similar concept is currently being developed by the Global Energy Interconnection Development and Cooperation Organisation, GEIDCO, sponsored by the Chinese Government (http://www.geidco.org/html/qqnycoen/col2015100724/column_2015100724_1.html).

cooperation and a broadly harmonised regulatory system, but even then problems can arise as noted below. The risks become greater when the interconnection is between EU countries and countries outside the EU, such as those in the Middle East, especially when the interconnection requires transit through multiple countries.

- **Competition** Different systems all have their own systems of pricing and taxation, even within the EU Single Market. For instance, the UK has a capacity mechanism (as discussed in Section 5) and a special carbon tax (a carbon price floor), significantly higher than the EU ETS price, for fuels for electricity generation. These elements (and such other differences as the degree of support for renewables) mean that there is not really a level playing field as between most European countries. For instance, electricity prices in the UK are higher than they would otherwise be as a result of the special carbon tax; exports from France benefit from these higher prices, yet generators in France cannot benefit directly from UK capacity payments or renewables support. For these reasons, generators within any one country may well resist the construction of interconnectors, which can expose them to what they would regard as unfair or at least unwelcome competition.

All these factors have meant that in practice interconnector decisions tend to be highly political rather than purely technical. The EU has tried to overcome these problems in various ways. The targets mentioned above have been supported by measures in the 2013 Energy Infrastructure Regulation and the Trans European Energy Networks Regulation, including the availability of financial support for 'Projects of Common Interest' (PCI - mainly interconnectors) and streamlined national planning procedures. The EU is also trying to address regulatory obstacles. It may be that the eventual goal is to create a pan-European regulator on the lines of the Federal Energy Regulatory Commission (FERC) in the US (which oversees inter-state trade and the transport of energy) as the proposal for an Energy Union calls for 'effective regulation of energy markets at EU level where necessary', see Buchan and Keay 2016. Meanwhile, however, the focus is on closer cooperation between European regulators, particularly via the Agency for the Cooperation of European Regulators (ACER), and through closer cooperation of transmission system operators through ENTSO-E. The development of the Single European Market, with its encouragement of market coupling, should also reduce many of the uncertainties surrounding price formation. However, the main problem remains, namely to decide whether the benefits of new interconnectors exceed the costs and to determine how those costs and benefits should be shared.

The EU has developed broad regulatory approaches for interconnectors (under Regulation (EC) No 714/2009). This sets rules for the allocation of capacity and allows two routes for financing interconnector investment:

- A regulated route which provides for third party access and a regulated rate of return on much the same basis as other transmission assets in the national network.
- A 'merchant' route which allows exemption from regulation but leaves developers full upside and downside risks.

However, EU rules effectively impose a large range of conditions on the granting of exemptions. Most new projects have in practice gone for the first option.

So the EU has taken significant steps to mitigate the obstacles. Nonetheless, problems remain:

- At the level of overall regulation, the fact that no equivalent to FERC yet exists in Europe adds to the time taken to reach decisions and the uncertainty of the outcomes. In this sense, Europe is arguably under-regulated.
- However, from another perspective Europe is arguably over-regulated. It is not clear whether the regulatory approach described above is sufficiently flexible or light-handed to cater for the various circumstances which may arise when new interconnectors are built.
- But perhaps most fundamentally, the EU has yet to create a genuine single market when it comes to support for renewables. Not only do different countries use different policy instruments to

provide different levels of support to different sources, but they are profoundly reluctant to extend this support to sources outside their national territory (see OIES 2014). These differences of approach, and their national focus, creates inherent market distortions and lead to power flows driven by policy decisions rather than market dynamics (Buchan and Keay 2016). In these circumstances, not only are interconnectors being used for purposes which do not increase overall system efficiency (for example loop flows through Poland and other countries caused by excess generation in Germany) but the obstacles to using interconnectors for the purposes of efficient decarbonisation are compounded. It is not just the inherent difficult of building interconnectors, but the reluctance of member states to import renewable power from external sources which is impeding trade. While the EU 2030 Energy and Climate framework is attempting to introduce a more harmonised approach it is difficult at this stage to see how far it will succeed in this, or indeed what the impact on a post-Brexit Britain might be.

In the longer term, the whole approach to interconnectors may in any event need to be reconsidered. The issue is a fairly fundamental one. In the early days of liberalisation, the concept was developed of electricity as consisting of various separate elements: generation and supply, which were inherently competitive, and the network businesses of transmission and distribution, which were thought to be intrinsic monopolies. The whole basis of the EU approach to liberalisation was to separate out ('unbundle') these different elements, and apply different pricing regimes: regulation for the networks, a largely free market approach for the other elements. But the idea of 'unbundling' was always based on a considerable degree of simplification. As noted in the introduction to this section, it is not unusual within electricity systems for generation investment and network investment to be alternative options for dealing with a particular problem (therefore in competition with each other). Such a situation is likely to be particularly frequent in relation to interconnectors – almost by definition they are not part of a particular network but a link between two networks and therefore more liable to suffer from congestion. In such a situation, where there is excess generation on one side of the constraint and a deficit (or high priced generation) on the other side, there will usually be two potential solutions, namely to expand the interconnection or to build more generation on the deficit side. If the two options are subject to different regulatory arrangements, it will be almost impossible to create a level playing field, especially given the various obstacles described above. Add in the further complications of comparing demand response as an option for dealing with the issue (at a time when its economic potential remains obscure within current market arrangements, as described in Section 5) and the task seems almost impossible.

It may well be the case that in the longer run a fundamental rethink of interconnector regulation will be needed. Even now – for instance, in relation to the UK capacity market, as described below – the issue is causing significant difficulties.

4.2.b UK

The UK (or more strictly Great Britain) currently has four electricity interconnectors, which link the island to France, Ireland, Northern Ireland and the Netherlands. These links amount to about four Gigawatts (GW), or rather less than 6 per cent of generation capacity. The UK regulator Ofgem accepts that this is below the level of interconnection which would be in the consumers' interest (for the reasons given above). Ofgem traditionally preferred the 'merchant' model of interconnection construction as more consistent with its fully deregulated electricity market. However, it found it increasingly difficult to deliver the amount of interconnection it thought was needed through this route. In 2014 it therefore introduced a new regime which offered the two alternative routes described above and in particular a version of the regulated route known as 'cap and floor'. This sets upper and lower limits on the revenue available from an interconnector investment (if revenues exceed the 'cap' excess revenue is returned to consumers and the converse applies if revenues fall below the 'floor'). This reduces risk for developers.

However, Ofgem must approve the use of the regulated ('cap and floor') approach and only does so where there are likely to be benefits for UK consumers. While the new system is relatively new, this can create uncertainties and delays for new interconnector proposals. For instance, Ofgem declined

to allow the 'cap and floor' approach to be applied to a proposed Irish interconnector (Greenlink), at least in its original version, on the basis that British consumers would not receive sufficient benefit. The main purpose of the link was to facilitate the export of Irish wind power, which could more easily be absorbed within the UK system than within the Irish system on its own. (Ironically, perhaps, the project also attracted considerable public opposition in Ireland, on the grounds that there would be environmental damage there while the benefits flowed to the UK.) It also took some time to establish whether the project could be brought within the UK system of renewables support rather than the Irish system, despite the fact that it was originally designed to supply the UK only. In other words, the fundamental situation remains that national regulators and public opinion continue to view issues in terms of their national interests. Interconnection decisions, even between friendly countries, remain highly political (UKERC 2016).

Despite these uncertainties, since Ofgem announced its new approach in 2014, a number of new interconnector proposals have been put forward, all except one proposed originally on the basis of the cap and floor approach, for connections with France, Belgium, Norway, Denmark and Ireland. Even if all of these were built, the UK - though a little above the 10 per cent target - would still have a relatively low level of interconnection compared to its European neighbours. In the longer run, however, there are also proposals for more ambitious connections, for example with Iceland, which could add significantly to capacity. However, these projects have been cast into doubt as a result of the Brexit vote. Developers will want answers to questions like those mentioned above and the following: will their interconnectors be eligible to receive capacity payments in the UK or, where relevant, renewables support? Will UK interconnection projects benefit from PCI funding from the EU? How will the regulatory framework change as a result of Brexit? At the time of writing (February 2017) the UK government had barely developed an overall approach to the Brexit negotiations, much less a detailed position on questions like these, so it is likely to be some time before the investment climate is clear.

This uncertainty could be costly for the UK – one study (by Sia partners – Sia 2016) has estimated the costs as follows:

- By 2020, in any Brexit scenario, capacity margins will be between 2 per cent and 6 per cent lower than they would have been in a No-Brexit scenario.
- By 2030, in the Switzerland scenario (where trade takes place, but the UK is not fully integrated into the single electricity market) capacity margins will be between 6 per cent and 12 per cent lower than in a No-Brexit scenario.
- The yearly forgone benefits of interconnection are quantifiable in the neighbourhood of £430m/y.

Apart from the viability of future interconnector projects, another live issue in the UK is the participation of interconnectors in the UK's capacity auctions. This has been allowed since 2015, despite the objections of some conventional generators who argued that interconnectors were transmission assets, not generation assets. At first sight, this raises the wider question of principle outlined above, although in practice the UK government's approach seems primarily pragmatic. On the one hand, it was under some pressure from the EU not to restrict the capacity market to domestic producers only, and it also wanted to increase the amount of competition in the market to create downward pressure on prices. On the other hand, it could not readily identify a way of allowing generators situated outside the UK to become eligible for capacity payments. How would the UK ensure that power flowed when needed unless there were interconnector capacity available? Would not such capacity be already utilised in any event in a situation when, due to the generation shortage in the UK, prices were likely to be high and thus market forces would be ensuring the use of the interconnector in any event? What would the impact be on markets and market prices in the country of origin and how would that country's regulators react? And so on. The easiest way through these problems was to allow the French Interconnector to participate as an entity, despite the fact that it is not a generation source as such. However, Ofgem is understood to be considering the decision and the possible distortions it entails. It may be that it will propose some changes to the regulatory system to help ensure a level playing field.

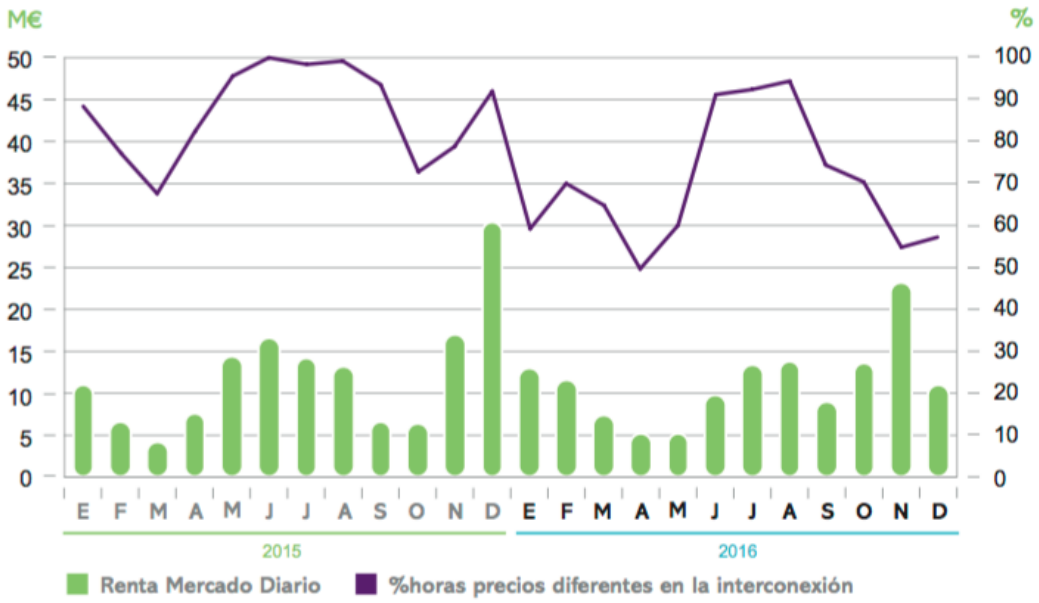
Overall, as the brief description above indicates, although the UK has tried to develop a 'merchant' approach to the construction of interconnectors, it has not had a great deal of success in this effort. Recent experience only demonstrates yet again that, despite all the strong arguments of principle in favour of the construction of new interconnections, in practice such proposals tend to get bogged down in complicated political argument. It is likely that, at any rate in the UK, the amount of interconnection will remain well below the level the government and regulator consider optimal for some considerable time to come.

4.2.c Spain

Spain has commercial interconnection capacity with France, Portugal and Morocco. France has a maximum export capacity to Spain of 3500 MW, compared to Spain's maximum export capacity to France of 2650 MW. Portugal has a maximum export capacity to Spain of 3100 MW and Spain's maximum export capacity to Portugal is 2300 MW. By contrast, Spain and Morocco share the same maximum export capacity of 800 MW.

The interconnector with **France** and therefore with continental Europe is equal to about 3 per cent of Spain's total generation capacity (105 GW), and a smaller share if one considers this interconnector in terms of the Iberian market[28]. Interconnector restrictions at this border are why Spain's electricity system is considered an island[29]. As a result, day-ahead prices on either side of the Spain-France border usually differ. The new interconnector Santa Llogaia – Baixas that was commissioned in 2015 doubled the exchange capacity and diminished the price differentials slightly. However, Spain and France are still far from achieving a full price convergence. Chart 12 illustrates that, in 2015-2016, prices on either side of the border differed between 50 per cent and 100 per cent of the hours (right hand scale) and that monthly congestion rents varied between about €5 million and €30 million (left hand scale).[30]

Chart 12: Congestion rents and percentage of hours with different prices across the Spanish-French interconnector: 2015-2016



Source: OMIE 2016, p. 19

[28] It makes sense to refer to the Iberian Peninsula because Portugal can only sell electricity to the rest of Europe through Spain.
29 It is also worth noting that Spain has very few alternatives for interconnection, whereas the UK has many, making Spain and the Iberian peninsula even more isolated.

[30] OMIE 2016

Spain's main priority with respect to international trade in electricity is to increase interconnector capacity with France. Spain makes all of the standard arguments in favour of increased interconnection capacity with France, including support for security of supply and the improved efficiency of markets. Of particular relevance to this paper, Spain argues that limited interconnection capacity with France raises the cost of developing renewable capacity. On a number of occasions, Spanish peninsular electricity demand has been as low as 22 GW, when available wind capacity has been around 18 GW. Because it is costly to stop and then restart nuclear plant and other inflexible facilities, wind power is curtailed even though the marginal costs of the latter are close to zero. Spain argues that to meet EU targets with respect to decarbonisation and renewables, greater interconnection is required. Currently, there are three projects being developed to raise interconnector capacity with France to 8000 MW, including one submarine project in the Gulf of Vizcaya, and two projects in the eastern Pyrenees. These projects have the political support of the European Union and both French and Spanish governments, but negotiations over their realization are slow.

Expanding interconnector capacity is not straightforward for a number of reasons. One issue is strong opposition by communities near the border on the grounds of environmental damage. Another possible issue may be that French generation (nuclear) is not particularly flexible and might have problems dealing with intermittent flows, especially if they are simultaneous with German wind flows. In any case, interconnectors also generally require reinforcements in national networks and it may be unclear how the costs will be recouped. This is especially relevant in the south of France. Finally, there is a question of whether the costs outweigh the benefits, especially if they require tunneling through the Pyrenees. The prospect of major investments in national networks and the interconnector requires evidence that the benefits outweigh costs.

There is a more general problem that applies to most interconnectors, namely how to share the costs and benefits of an investment. Normally, as illustrated in Chart 13, France exports to Spain because prices in France are lower; in part this reflects a 7 per cent tax on Spanish generation. Through imports from France, prices in Spain are lower and prices in France higher than would be the case without the trade; more interconnector capacity implies rising prices in France. However, very recently, due to extended maintenance of nuclear plants in France, Spain has been a net exporter to France, contributing to higher prices in Spain and lower prices in France than would have occurred without the interconnector, leading some in Spain to argue for a temporary closure of the interconnector. These developments illustrate the potential benefits of interconnectors, but they also reveal the political difficulties of sharing the costs and benefits.

Chart 13: Balance of electricity trade with Spain

BALANCE OF INTERNATIONAL PHYSICAL ELECTRICAL ENERGY EXCHANGES — GWh

	France	Portugal	Andorra	Morocco	Total
2012	1,883	-7,897	-286	-4,900	-11,200
2013	1,708	-2,777	-287	-5,376	-6,732
2014	3,567	-903	-235	-5,836	-3,406
2015	7,324	-2,266	-264	-4,927	-133
2016	**6,110**	**6,688**	**-286**	**-5,199**	**7,313**

Positive value: importer balance; Negative value: exporter balance.

Source: REE 2016, page 19.

By contrast, the interconnection with **Portugal** reflects a comparatively successful political agreement to integrate the Spanish and Portuguese electricity markets into a single Iberian market.

Interconnection capacity is sufficient for prices on either side of the border to be the same more than 90 per cent of the time and for congestion rents to be much lower than at the border with France[31].

The day-ahead market is configured as an Iberian market in which the agents in the Spanish and Portuguese electricity systems participate under the same conditions, managed by the Iberian market operator (OMIE). The Iberian day-ahead market is part of a process referred to as the Market Coupling of Regions (MCR), which uses the same systems, procedures and algorithms developed by market operators in the project known as the Price Coupling of Regions (PCR). As of January 2016, MCR applies to market operations in nineteen European countries. However, even within the Iberian market, there is a reluctance to optimise fully, for instance to coordinate capacity expansion for new energy resources.

Morocco has excellent wind and solar resources, but deployment will be limited unless interconnectors with Europe are built, as they have been with Spain. Spain is a net exporter to Morocco and this may provide Spain a degree of geopolitical influence.

Unlike the UK, Spain has not introduced legislation that would enable companies other than REE, the transport system operator, to build, own or manage interconnectors. The European Commission maintains that Spain has not properly transposed the EU Directive (2009) on norms for the Single Energy Market[32]. It recently issued a Reasoned Opinion on this matter, requesting that Spain revise its legislation to allow for merchant interconnection facilities. If Spain does not do so, the next step would be an appeal by the European Commission to the EU Courts.

There are wider issues here. One is the relationship between the transport owner (the TO) and management of the system by the TSO. The standard model in the EU is to combine the two functions within the same holding company (for example REE in Spain). Spain's legislation gives REE exclusivity in the ownership and operation of national and international networks involving Spain. If Spain were to introduce legislation that allowed competition in the building, owning or management of interconnectors, this could introduce new network owners or operators into the Spanish national system.

This points to other important issues: whether to separate more clearly the operation of the system from the ownership of the networks, and the role of government in deciding what networks to build. As the UK example suggests, it is becoming increasingly difficult to treat interconnectors and networks differently from generation and other energy resources. Although there are good reasons for wanting to coordinate system operation with network ownership and management, the case for separating system operations is becoming stronger. In particular, the decision with respect to what networks are needed should be taken within the context of optimising the entire system, and not building more network capacity than is needed. In Spain, the system operator is responsible for proposing a long-term system expansion plan for the Ministry to assess and eventually approve, with the necessary modifications. In that process, the CNMC analyses the proposed plan and on various occasions it has concluded that the system operator's demand forecasts are too high[33]. This probably reflects the system operator's preference to ensure greater security of supply, but presumably also the fact that the owner of the transportation assets earns a rate of return on approved assets.

Finally, if competing companies can build and operate interconnectors, what role should government play? Spain could follow the UK by offering the possibility of a regulated route with third party access and a regulated rate of return (based on the cap and floor approach). Alternatively it could propose a merchant route which allows exemption from regulation but leaves developers full upside and downside risks. The regulated route is far more likely in Spain. However, the merchant approach and even the regulated approach have proved difficult in the UK, mainly because decisions about interconnectors are heavily influenced by national politics. This is unlikely to be different in Spain, especially given the limited number of interconnection alternatives and the need in almost all cases to negotiate with representatives of the French government. In any case, opening the interconnection

[31] OMIE, Informe de Precios 2016, page 18.
[32] http://cincodias.com/cincodias/2016/09/29/empresas/1475169408_964733.html
[33] See for instance CNMC 2015b, pages 16-19.

market to competition will require rethinking about how to make this feasible, and how the government will assess alternative interconnection projects. To date, as we have noted above, the system operator proposes a long term expansion plan for the government to approve, with the CNMC offering its assessment of demand forecasts and the need for new capacity. For this model to work under conditions where REE is competing with other interconnector companies, the independence of the system operator will become increasingly important.

4.2.d Conclusion

Interconnectors are important elements of any sensible approach to decarbonisation; however, they entail a host of difficult political and regulatory problems. Neither country has got very far in solving these problems, and future progress is in any event likely to be slow. It is complicated by such factors as national concerns and differences and by the difficulty of creating a truly competitive basis for investment. In addition, in the case of the UK, there are all the uncertainties caused by Brexit. It is therefore difficult to draw wider conclusions about the way forward in this area. However, there is a growing recognition that interconnectors may be an alternative to generation and that network operation should therefore be more clearly separated from network ownership.

4.3 Network pricing

4.3.a Introduction

This section deals with network pricing itself, while the wider issue of the role of networks and their regulation is dealt with in Section 4.1. Network regulation is mainly about the signals and incentives given to the networks themselves; network pricing is more about the signals for network users, namely generators and consumers. Network pricing is a fairly significant element in overall electricity prices, accounting for around 25-30 per cent of the average household bill in most parts of the EU.

Before liberalisation, network pricing hardly existed as an issue. Electricity companies generated (or bought) and sold electricity and provided they made a margin over their overall costs, it did not matter greatly whether the costs arose in transmission, distribution or supply, and they often had only a very limited understanding of the underlying cost drivers. With liberalisation and unbundling, all this changed, and it became critical for both the companies themselves and their regulators to understand the costs involved in the now separate functions of transmission and distribution and to reflect them properly in prices. In the early stages of liberalisation, the problem was a relatively simple one, that of finding an appropriate balance between giving the right economic signals on the one hand, and creating a practical, fair and comprehensible system of charging on the other. With the 'new era' challenges, matters have become much more complex. Policy considerations have increasingly come into play, as discussed below. For example, how far should network pricing facilitate the move to a low carbon system, and what is the best way of achieving it?

Economic efficiency is still an important starting point, of course. It normally points to having strong locational and demand elements in network pricing – after all, networks are there to transport electricity from one place to another so the place at which electricity is generated or consumed is an important cost driver, while the size of the network needed is determined by maximum demand. Many economists would argue for 'locational marginal pricing' under which electricity has a different price at every 'node' (every point of entry or exit) to the system and the price varies according to generation and offtake at any particular time. Differences between the price at one node and another will then give clear economic signals as to the different value of electricity at particular points and hence the economic case for transporting electricity from one point to another. Networks, on this basis, exist essentially as a function of the scope for arbitrage and the key driver is the electricity market itself.

The difficulty with this approach is that it is complex and potentially confusing. It is not usually possible to set up liquid markets at every node on the system in such a way as to give a constantly changing and transparent real time price. Instead, algorithms are used, which may be opaque and difficult to understand. It can therefore be difficult on this basis to create the sort of clear benchmark price which is often regarded as necessary to promote competition and enable associated and derivative markets to develop. Instead, policy makers in the EU have tended to prefer broader-based markets extending

across regions or countries so that a single price can emerge and a fully liquid energy market develop. This sort of market does not drive internal network investment, which is subject to the sort of regulatory arrangements discussed in this and the distribution sections of the paper.

In its single electricity market, the EU has developed a sort of compromise system, based on pricing 'zones' which are in principle based on electrical rather than political considerations. Each zone has its own market and market price; however, the markets can be coupled via the day-ahead market in such a way as to set a single price for both coupled zones up to the point where transmission constraints intervene. If the constraints lead to a sustained difference in prices, this should then create the case for investment in interconnections between the markets in order to take advantage of the arbitrage opportunities. However, there are still question marks over transparency: defining when the constraints arise is calculated according to algorithms which some commentators have questioned. There are also political considerations. Most countries prefer to have a single zone nationally, since any departure from this principle has distributional consequences, benefiting some regions at the expense of others and this may create problems, for instance for regional policy. Sometimes, the Commission has persuaded countries that, despite these problems, they should create separate pricing zones (for example Sweden, which was divided into four pricing areas in 2011 following Commission pressure). However, in other cases, there is a reluctance to take action, even where there is a clear argument of principle that separate pricing zones are needed (for example in the UK where Scotland should probably in technical terms be separate from England and Wales, or in Germany where constraints are increasingly developing between the north and south of the country as a result of the nuclear phase-out).

However, these problems are relatively straightforward as compared with those posed by decarbonisation. Locational pricing certainly makes sense in relation to conventional generation sources – within limits, they can be built at locations which minimise costs from the perspective of the wider electricity system, so there are strong reasons to give the appropriate signals in network prices, for instance to discourage new generation sources in areas which are already over-supplied. With renewable sources, the logic is less clear. By and large, there is much more limited flexibility in relation to locational decisions for renewable sources. These sources have to be sited where the natural resource in question is available at economic levels, and where the environmental problems are manageable. If they are being built (and given special support) for reasons of the public good, with the costs involved being 'socialised' (spread over the customer base as a whole), it may make little sense to penalise the same sources according to their location. It may be better to socialise the network costs as well as the generation costs, despite the loss of economic efficiency, in the interests of decarbonisation. There is no absolute answer to this dilemma and various compromises have been tried in different jurisdictions to give some locational signals while not unnecessarily discouraging renewable sources.

The comments above apply mainly to sources which are normally available at some distance from the point of consumption. But analogous problems arise with distributed resources, like solar photovoltaics, which are often available very close to (or at) the point of consumption. How far should they be rewarded for reducing the need for network transmission? Again, there is no simple answer. Some distributed generators believe that they are not properly rewarded for the benefits they provide to the system. On the other hand, some utilities and regulators would argue that these sources are not bearing their full share of network costs (for example the problem discussed in section 4.1 above as the 'death spiral'). Furthermore, as the volume of such sources grows, the impact on the system will also change and so, perhaps, should the charging arrangements – for example, (again as noted in the Distribution section) in many areas, distributed sources are now so widespread that the distribution system actually exports 'back' to the transmission system. Arguably, such sources should bear their share of transmission costs, though this does not generally happen at present. In any case, as electricity systems become more decentralised, the locational signals in access tariffs for distribution networks will become increasingly important and often imply larger differentials than for transmission.

So the 'new era' challenges present some difficult conundrums, which are leading to different responses, as discussed in more detail below. In addition, there is the fundamental problem

discussed above that the whole basis of unbundling and the role of networks have come into question which makes it difficult to manage price regulation in such a way as to create a level playing field for competition. Transmission (or network expansion more generally) may in the future be in competition with generation; conflicts may arise more frequently between the roles of network owners and system operators; new players, like storage, may be part of the network or participants in the competitive market, and so on.

Already, some regulators are worrying about aspects of the problem. For example, in the UK capacity market, interconnectors are effectively treated as generation assets and are in competition with other generators, yet for other regulatory purposes they are treated as monopoly assets subject to regulation. Similar issues could also arise at the other end of the system. For example, if the development of the distribution network follows a 'microgrids' scenario (see Section 4.1), each microgrid may be engaged in trade with the distribution grid (or with other microgrids) on the same basis as generators and consumers. But is it to be treated in the same way as other parts of the grid or as a competitive actor? Also in the UK capacity market, low bids by diesel generators might be explained by lower network charges, as they are distributed assets. In short, in the longer term some fundamental rethinking of the whole approach to networks (as opposed to generators and consumers) may be needed. However, this section is mainly concerned with experience to date in addressing the key challenges thrown up by the 'new era' changes which are already in place. Some additional issues connected specifically with the growth of embedded generation, are discussed in Section 5.

4.3.b UK

Compared with some European systems, the UK has relatively strong (but, as noted below, possibly still insufficient) locational and demand elements. It is not a simple 'postage stamp' arrangement with a single price per unit for all network transport.

The main charging elements which vary on a regional basis are:

- Connection charges which are the costs incurred in connecting generators (or users) to the grid. They are situation specific and reflect the actual costs involved. However, there has been a long standing debate about what exactly are the 'costs' involved. There has already been a general move across Europe from 'deep' connection charges to 'shallow' (or in some cases 'shallowish') charges. The issue is how much of the system expansion cost associated with new generation connections is attributed to particular generators. Before about 2008, the practice was generally 'deep' charging. Under this approach, all such costs, including general system reinforcement, were charged as part of the upfront connection charge. This could prove a strong disincentive to the development of new renewables generation, especially in new provinces where there was a risk that the first-comer would have to pay an unfair share of the cost, leaving later arrivals to 'free-ride' on the opening up of the province to new generation. Increasingly, therefore, European systems have moved to 'shallower' connection charges, under which only the direct costs of linking a generator to the Grid are included. All other system reinforcement costs are 'socialised' (hence the rise in transmission charges noted below). The UK operates a sort of 'hybrid' system under which 'shallow' charges apply to connections to the transmission network (where of course the costs could in some circumstances be very much greater if the 'deep' system were applied) while 'deep' (or at least 'deepish') charges apply in distribution. Here the companies operate to a common methodology which allows them to 'include an amount for reinforcement of the licensee's Distribution System that is based on a proportionate share of the costs of such reinforcement and is charged at the time of connection'.[34]'
- Use of system charges at both transmission and distribution levels are designed to cover wider investment in networks. These are regular charges which vary according to usage (as opposed to the one-off upfront connection charges) and they have fairly strong locational elements. TNUOS (Transmission Network Use of System) charges vary on a zonal basis (not the same as the

[34] https://www.dcusa.co.uk/SitePages/Home.aspx

market pricing zones referred to above – these are relatively small areas) and create disincentives for generation in areas of excess production. The differences can be substantial – the overall system is quite complicated but, as an example, the 'system peak' tariff in Lothian in Scotland is £4/kW while the tariff in London is -£3.83 (meaning generators have to pay in Lothian, where there is an excess of generation, but receive a credit in London, where there is an excess of demand). Larger users are also exposed to these use-of-network costs, via an element in their bills called 'Triad' charges. These are calculated on the user's maximum demand across three periods of system stress occurring between the beginning of November and the end of February. These periods normally fall between four and seven pm from Monday to Friday (though the Triad times may not correspond exactly with the actual three peak periods in terms of demand because of a rule that each such period must be at least ten days apart from another). Taken together they give a reasonable approximation of a user's contribution to maximum demand, which is in turn the main cost driver for investment in the network. Triad charges can vary considerably by region – from £16 to £39/kW across the country in 2015 for instance. These charges have risen substantially over the past few years and are expected to go on increasing at a rate well above general inflation (by 10-20 per cent per annum) at least until 2020, as network expansion to accommodate the new renewable sources continues.

- Distribution network costs also vary by location and Distribution Use of System Charges vary by region.
- Distribution losses are charged to suppliers on the basis of the difference between the amounts they input to the system and the amounts their customers offtake (or are calculated to offtake). As noted in the Distribution section, regulators are increasing the incentives on distribution companies to reduce losses.

In short, there are a number of elements in network charging which reflect location. The result is that typical household consumers in different regions will pay (slightly) different amounts for the same amount of electricity. The difference is only a few per cent but it still causes some controversy. While the impact on bills themselves is modest and although consumers are not charged separately for network costs, the underlying cost differences are quite significant. For instance, the electricity transmission component of household bills ranges from £21 per year in North Scotland to £37 in London and Southern England. With distribution costs, the difference is even wider, but in the opposite direction: costs vary from approximately £66 per year (London) to £122 (North Scotland). In response to concerns, Ofgem reviewed network charges and their distributional effect in 2015 (Ofgem 2015a). The main objective was to explain why regional differences arose in the first place.

In addition to the costs discussed above, there also locational cost elements which are 'socialised' rather than being borne by the user concerned, namely:

- Transmission losses: some electricity is lost in the form of heat as it is transported over long distances. While losses are smaller over high-voltage transmission lines than for distribution lines, transmission losses are still reasonably significant. They accounted for around 1.7 per cent of total electricity generation in Great Britain in 2014, and, unlike distribution losses, they are not reflected in particular charging elements. Instead, they are recovered by adjustments in the balancing market, and then charged, on a unit basis, across all system users. There have in fact been several attempts to introduce a charge for transmission losses but, for one reason or another, all attempts have failed. One problem is that losses reflect the distance travelled. As with the use of system costs, these charges would therefore would bear more heavily on remote generators, such as wind generators in Scotland. The Competition and Markets Authority (CMA) in the UK estimates that around £150 million could be saved over the next decade via a proper system of charging for transmission losses. They add that there would also be savings in the form of lower SO2 and NOx emissions, valued at up to a further £15 million. (CMA 2016).

- Transmission constraints: these are costs which arise when power cannot be transmitted to where it is needed, due to congestion on the network. This can prevent electricity from the cheapest sources of generation from being used; instead higher cost electricity, generated on the other side of the constraint, has to be substituted. As noted above, the biggest source of transmission constraints in the GB wholesale electricity market is on the border between Scotland and England. There is an excess of generation capacity in Scotland and limited network capacity to transport electricity south and the bottleneck has been worsening as a result of the increase in wind generation in Scotland. The low marginal cost of wind means that there are in principle increasing opportunities to sell wind-generated power in Scotland to English purchasers, opportunities which are often frustrated by transmission constraints. These congestion costs are currently passed on by the Grid through the balancing mechanism (it has to call on other generators to make up the gap and then make payments to the generators which could not be despatched) and averaged over all producers and consumers on a unit basis.
- The costs involved are arguably further increased by the 'Connect and Manage' system introduced in 2009. This was designed to enable generators (particularly renewables generators) to connect to the system more quickly than under the previous arrangements. Previously, the Grid had operated a queue under which it would not connect up generators until any wider transmission system reinforcements needed had taken place. Under the new arrangements, the Grid offers connection dates based on the time taken to complete a project's 'enabling works', in most cases ahead of the completion of the transmission system reinforcements required. The Grid notes that 'connecting generators ahead of the completion of wider works may result in additional constraints on the National Electricity Transmission System' and this has indeed proved to be the case. For instance, an Ofgem report indicated that whereas initially the proportion of constraint costs due to 'Connect and Manage' was well under 10 per cent, 'in the period covered by this report (2013/14) more projects have connected to the transmission system, bringing the total to 23 connected sites. The constraint costs related to these sites during this period were £69.4m, representing 30 per cent of the total constraint costs of £227.8m.' (Ofgem 2015b) This does not mean that such costs will inevitably increase. One of the aims of the system is to increase the incentives on the Grid to build the necessary new capacity and a number of lines have recently come into operation, so constraint costs could conceivably fall again. In practice, constraint costs vary from year to year. For instance, in 2011/12 they amounted to £324 million but in 2012/13 they fell to £170m, only to rise again in 2013/14. Nonetheless, they are a relatively significant proportion of balancing costs, which amounted to around £800 million a year.

As the description above indicates, network pricing is complex and represents something of a balance between various different objectives. The UK system has relatively strong locational elements and these can sometimes prove controversial, but it is arguable that in terms of economic principle, it needs to go further in the direction of locational pricing. There are also reasonably strong demand elements in larger consumers' bills (which as noted in section 5.3 can create useful incentives for demand response) but they do not affect most household consumption. Additionally it could be difficult politically to increase either the regional differentiation in household bills or their complexity. The longer term issues discussed in the Introduction are now being considered but have not yet entered the mainstream of network pricing.

4.3.c Spain

Spain's approach to network pricing is quite different to that of the UK. On the one hand, there are very few locational signals, with connection – albeit shallow – being one exception. This reflects the policy of charging a single national regulated network tariff for each consumer category, thereby socializing virtually all network costs, including transmission and distribution networks, losses and constraints. It also reflects a system without important transmission constraints, excepting the interconnection with France.

Where the grid operator has the opportunity to earn a return on a regulated asset base, or to pass through operating costs, the incentives are typically to ensure a very high level of security, rather than to minimize costs. For instance, as mentioned earlier, the CNMC has argued that the system operator's electricity demand forecasts were too high. This could lead to investment by REE that was unnecessary or untimely.

On the other hand, network tariffs in Spain do reflect the level of a consumer's contracted demand. Fixed charges based on contracted demand account for the bulk of revenues from network tariffs. In principle this could provide an efficient signal for consumers to reduce their peak demand in order to minimize cost. However, network prices are bundled together with levies and taxes into access tariffs, thereby distorting network price signals.

Current legislation (Article 16 of Ley 24/2013) distinguishes two different concepts that are included in access tariffs:

- Use of system or network charges (*peajes*) are payments for the use of the distribution and transmission networks. Consumers are charged on the basis of the voltage level at which they consume electricity, as well as their contracted capacity and the time/period of consumption. Generators pay by reference to the energy injected into the network. These network charges are the same throughout the country and include no taxes.

- Levies (*cargos*) are used to recover system costs, including the 'extra' cost of supporting renewables, cogeneration, supply to the islands, certain consumer groups, interest payments on the tariff deficit, as well as other subsidies and regulated costs. These levies are charged through the structure of the access charges, which implies that they are the same throughout the country and reflect the consumer's voltage level, contracted capacity and time of consumption.

As explained earlier in Section 2.3, the government determines the level of the network charges and the levies, as well as their allocation among consumer groups and generators. The network charges are supposed to be set by reference to a methodology established by the CNMC that should be economically efficient, transparent, objective and non-discriminatory, and allow recovery of the regulated costs of transmission and distribution. In fact, the CNMC methodology has never been formally adopted and the government sets both the network charges and the levies without using a transparent methodology.

Through access tariffs (network charges and levies) consumers pay most of the regulated costs of the system[35]. The network charges, which cover the cost of transmission and distribution networks, account for about 40 per cent of the access tariffs. The remaining 60 per cent reflect levies to finance public policies. [36]

For small consumers supplied by the distribution network, between 80 per cent and 90 per cent of the network charge is collected through the fixed component, while for the largest consumers, the fixed component is about 70 per cent. However, levies are collected mainly through a variable component of the access charge. Currently, the fixed capacity term is 69 per cent of the total access tariff (network and levies), and 60 per cent for small domestic consumers. This provides some guarantee of cost recovery, especially during periods of declining demand. It also provides signals to reduce contracted capacity and the consumer's peak demand, which should help to limit investment in networks. However, the tariffs do not reflect peak demand nor, as mentioned earlier, do they reflect location. Furthermore, the access tariffs include levies that have nothing to do with network costs. Consequently, the access tariffs do not provide efficient signals. Indeed, consumers may choose to

[35] Estimated regulatory revenues for 2016 were €17.2 billion. Of that, €13.8 billion were paid by consumers through the access tariffs, and €3.2 billion came from CO2 emission auctions (€450 million) and from other taxes (€2.7 billion) introduced in 2012 to eliminate the tariff déficit. CNMC 2015b, page 6.
[36] **CNMC 2015c**, page 5.

self-generate in order to reduce contracted capacity and access tariffs, even when self-generation entails higher economic costs than consuming additional energy through the network.

The debate has begun in Spain on how to reform access tariffs. The case for recovering the costs of public policy through general taxation was explained in Section 3.3 on the government wedge. There is also a case for changing the structure of network tariffs to provide more efficient locational economic signals. One proposal is that access tariffs should have a dynamic element that reflects the level of congestion, so that consumers who increase network congestion pay more and those that relieve congestion pay less. This approach is similar in inspiration to the UK's Triad payments for transmission use of system. However, the idea is that it would apply to distribution networks and that this element of the access tariffs would change in response to levels of congestion, just as electricity prices change in wholesale markets.

In short, the current Spanish treatment of network tariffs includes virtually no locational signals, and demand-related access tariff signals are distorted because they reflect the cost of non-network levies. The reliance on contracted demand, rather than energy, limits but does not stop the potential for revenue erosion when demand falls.

4.3.d Conclusion

Decarbonisation has brought with it increasing decentralization of energy resources, and this in turn has generated new thinking about how to set network tariffs. There are two general trends: more location specificity in network tariffs, and greater concern for providing economic signals to charge for and manage congestion.

The UK is well ahead of Spain on both of these fronts, with Spain having an additional challenge, namely the distortions that result from including levies to cover various public policies within the network (access) charges. On the other hand, Spain's network tariffs reflect contracted capacity, rather than energy transmitted, and so are less vulnerable to erosion when demand falls or consumers self-generate. Furthermore, there are proposals in Spain to improve the location-based signals, for instance by introducing an element of the tariff that reflects local congestion.

These trends suggest a direction for network pricing, which will be increasingly location-specific and reflect congestion, while structured in a way that provides some assurance of fixed cost recovery of network costs. Some of the specific challenges which arise in this connection are discussed in Section 5 in relation to embedded generation.

Section 5 – Promoting balanced investment

One of the fundamental problems underlying many parts of this study is the fact that markets alone will not lead to the development of the low carbon system of the future. The problem is perhaps most acute in relation to the development of the new resources, particularly low carbon generation, needed to create such a system. It will require wholesale change not just in the physical components of the system but also in markets and operation, given the main focus hitherto has been on investment, namely encouraging the construction of low carbon generation, particularly renewables. This narrow focus has led to a range of unanswered questions, as discussed in the overall conclusions to this study in Section 6. This section is more directly concerned with the measures which have been implemented in the UK and Spain to promote low carbon resources including demand side resources. (Storage would also be a candidate for this section, except for the fact that it has hitherto received little policy focus in either country: in the UK, for example, there is not even a regulatory definition of storage[37]).

5.1 Renewables Support

5.1.a Introduction

Apart from policies that reduce subsidies to fossil fuels, or raise their costs (for example the Large Combustion Plants Directive (LCPD), the Industrial Emissions Directive (IED) , and the EU Emissions Trading System (ETS)), and those that ensure privileged access for renewables to the system, governments have introduced a variety of renewable power support schemes that are categorised as either production-based or investment based (namely operating and investment aids respectively in EU terms).

Production-based schemes pay companies based on the energy produced (per kWh). There are many forms, with the most common in the EU related to prices: feed-in-tariffs (FiTs) and feed-in-premia (FiPs). FiTs are long-term contracts or regulatory commitments between the government and the renewable energy company in which a payment is made for each unit fed into the grid. FiP schemes involve a payment added to what the generator earns by selling into the energy market, with the premium fixed, floating or subject to a cap and floor. FiPs may also be designed as Contracts for Differences where the generator receives a fixed (option) fee and a guaranteed energy (strike) price. Another form of production-based incentive is quantity-oriented. These involve quota obligations on market participants to produce or obtain a certain amount of their energy from renewable sources, or competitive tendering by government, mainly through auctions.

Investment-based schemes may also be related to price or quantity. Price-based approaches include investment tax credits and other fiscal arrangements aimed at lowering investment cost. Quantity-based investment incentives usually involve the government tendering for a certain quantity of capacity (say of solar PV) and awarding the contract to the bidder with the lowest price bid (per kW).

There are also mixed incentive arrangements that combine production and investment. For instance, the government guarantees a ‘reasonable’ rate of return on assumed investment, assuming an efficient operator, and takes account of revenues earned selling energy in the market as well as assumed operating costs.

There is no optimal incentive arrangement to support renewables, but there is a consensus at least about the following. Firstly, the mechanism (and the country that organises it) should reduce investor risk and hence the cost of capital on these highly capital-intensive investments. Secondly, the mechanism should include other cost containment measures in order to be sustainable. Thirdly, it should take advantage of the potential for competition among the potential investors, not only to put downward pressure on prices, but also to encourage innovation that is relevant for the market in

[37] See http://www.solarpowerportal.co.uk/news/sta_resumes_calls_for_removal_of_barriers_to_energy_storage

question. Finally, the mechanism should have good operating incentives, for instance to encourage renewable generators to operate when to do so is optimal for the system as a whole.

However, there are some more fundamental problems arising from systems of renewables support, particularly when they take the form of production-based incentives. Such support distorts market operation as some participants are getting higher levels of payment than others (not necessarily related to market prices) and hence there is no level playing field in the short-term. Nor is there a level playing field for investment – indeed, as noted in Section 3 one of the purposes of many renewables support schemes is to reduce risk for investors. That not only means that they face lower risks than other investors, but their presence in the market actually increases risk for those investors. In other words, these support schemes distort market operation in both the short- and long-term and cannot be regarded as sustainable. The issues involved are beyond the scope of this paper (they are covered in OIES 2016). The main message, which is discussed in more detail in Section 6, is that it is vital that policy makers do not consider individual schemes, such as those for renewables support, in isolation, but think through their consequences for the system as a whole.

5.1.b UK

The UK has experimented with various forms of renewables support. The first approach, via the Non Fossil Fuel Obligation (NFFO), was introduced at the time of electricity privatisation in 1990. It took the form of an obligation on distribution companies to buy a certain amount of generation from non-fossil sources, combined with a fixed percentage added to final electricity prices (the Fossil Fuel Levy – around 10 per cent of the price) with the revenues then allocated to low carbon producers. The scheme was mainly designed to deal with the legacy cost of nuclear, although there was a small renewables element, conducted via auction rounds, which kept the overall impact on electricity costs down to a relatively low level.

The NFFO arrangements were replaced by the Renewables Obligation Scheme in 2000. It reflected changed circumstances: the nuclear issue had (at least seemingly) been dealt with; full privatisation and competition had been introduced; and the UK now had more rigorous climate change objectives under the Kyoto Protocol. Its aims were more ambitious and it was more closely linked with the new market structure. It stated that a fixed percentage of each supplier's electricity had to come from renewable sources. The obligation was tradable (in the form of Renewables Obligation Certificates (ROCs)) and suppliers were naturally concerned to keep their costs down by purchasing the cheapest ROCs available in the market. The system started off as technology neutral but a system of 'banding' was introduced at a later stage under which different sources received different numbers of ROCs. For instance, offshore wind plants might receive 2 ROCs per MWh, onshore wind installations 0.9 ROCs per MWh and sewage gas-fired plants half a ROC per MWh. The change to a banded system reflected the fact that the ROS had two broad objectives – to encourage physical investment in new renewable sources to help reduce emissions and to help promote the development of less established sources likely to have potential for the future. The overall cost was capped by setting a 'buy out' price for suppliers. Those which failed to meet their obligation by the purchase of ROCs could pay a penalty price instead and the revenues generated would then be recycled to renewables producers.

The ROC system seemed to meet the objective of efficiency, but there were doubts about its effectiveness and in particular whether it would enable the government to meet the UK's stringent renewables target under the EU 20/20/20 goals agreed in 2007 (the UK target was 15 per cent, but as that applied to energy as a whole, it implied a target for electricity of over 30 per cent as compared with a level then well under 10 per cent). The problem was that the renewables obligation worked in such a way that developers were exposed to considerable price uncertainty, both in relation to the wholesale price of electricity and to the value of the ROCs themselves. Experience seemed to suggest that the FiTs adopted in many other European countries, which offered a fixed price per kWh, offered greater certainty for investors and were more effective in delivering large quantities of renewables, though it was less clear how effective they were at containing overall costs. (In fact, much of the debate stemmed from a misunderstanding of the economics: it is not that one approach is better than another, rather that one approach is better suited to a particular set of circumstances - see OIES 2013).

However, the political tide was running in favour of FiTs. In response to a series of reports and analyses, the UK coalition government which came into power in 2010 embarked on a major programme of electricity market reform designed to improve the investment climate for renewables. The centrepiece of these reforms, as regards renewables support, was the development of a form of Feed-In Tariff based on Contracts for Difference (FiT CfDs) which paid low carbon generators a fixed price made up of a wholesale market price, topped up as necessary by a further payment (or, in theory discount), to bring the overall price to the level of the strike price set in the contract. One key consideration was that it offered a more secure income stream than the ROC system. The government believed (and a number of studies showed) that this would bring down the cost of capital and hence the overall cost of the decarbonisation process.

Initial contracts (including the one nuclear contract in place, though not yet activated) were set at fixed strike prices determined by the government, but auctions have now been introduced so that the strike price under contracts for particular forms of generation is set via competitive bidding. In its approach to technology preference, the auctions broadly try to achieve the two aims mentioned above: CfDs are allocated across two 'pots', one for established technologies, such as solar and onshore wind, and one for emerging technologies, primarily offshore wind.

As noted in Section 3, this competitive approach has been very successful in bringing down prices without any apparent impact on effectiveness, though the financial constraints imposed by the Levy Control Framework and changes in government policy have slowed down projected renewables development. Nonetheless, the overall growth in renewable power in the UK has been very rapid. It now amounts to around 25 per cent of electricity supply (up from under 10 per cent before 2010). The latest full data relate to 2015 – that year for instance, both offshore wind and biomass increased by around 30 per cent as compared with the previous year, while solar PV was up 87 per cent (DUKES 2016, Chapter 6). While full data for 2016 are not yet available, that year saw wind generated electricity overtake coal for the first time ever. So overall, despite the odd hiccup, the UK programme has been broadly effective both at encouraging investment in renewables and in keeping costs to a reasonable level.

5.1.c Spain

Spain has had two fundamentally different mechanisms to support renewable energy. The first, which lasted until 2013, was production-related and offered regulated FiT and FiP payments for different renewable technologies. Wind power, solar PV and concentrated solar power (CSP) plants were the main beneficiaries. This approach was very successful in attracting investment, but the overall costs of the remuneration regime were unsustainable. There are many reasons for this. One is that Spain promoted solar renewables when the technology was still relatively immature and expensive (costs have since fallen significantly). Under the legislation, Spain had the option to change the FITs either every four years or when 85 per cent of the targets were achieved, but the government did not do so. Another reason is that the government did not move quickly enough to cap the amount of solar PV and CSP that could benefit from the FIT's. This resulted in significantly more PV and CSP than had been planned and that could be financed through the tariff. Thirdly, Spain's electricity demand fell steadily from 2008 to 2015, largely due to an economic crisis, leaving Spain with significant excess generation capacity and great difficulty recovering these and other regulated costs through tariffs. This in turn led to a ballooning tariff deficit. However, it is important to recognize that the tariff deficit had been growing since 2000 and was already large before the recession and the very rapid increase in renewables began. Finally, there is a more fundamental issue: the failure of successive Spanish governments from 2000 onwards to set tariffs to recover the full costs of a range of regulated activities, or to finance these costs in a more sustainable way, for instance through general taxation or through a levy on all energies. This has resulted in the creation of a financial liability that future electricity consumers will have to bear unless these costs can be recovered otherwise.

The second renewable remuneration scheme, introduced in 2013, was part of the government's effort to stop the tariff deficit from growing further. Prior to the new remuneration scheme being introduced, the previous government and the new one introduced partial cost containment measures, including a temporary moratorium on new renewable projects, limits on the number of full load kWh that would be compensated, and the elimination of the FiP. However, the definitive change was to replace the

FiT/FiP scheme with a regulation that remunerated plants based on what the government considered a reasonable rate of return on assets. [38]

This new regime, which applies to existing assets and new ones, is supposed to ensure that owners of renewable assets receive no more 'incentives' than are required to obtain a 'reasonable' rate of return on investment, assuming efficient investment and operations. Under this regime, the renewable generator could be entitled to a 'specific remuneration' in addition to the energy market price, to compensate it for capital and operating costs that cannot be recovered in the energy market. The specific remuneration is based on two criteria: the installed capacity and therefore the initial investment, and the operation costs of the facility. For both criteria, the government makes assumptions about what the efficient investment and operating costs are for a standard generating asset. Here are some key features of the new regime:[39]

- The regime groups facilities into categories. There are several hundred different remuneration categories for cogeneration, PV, CSP, wind and other assets, based on common features such as installed capacity, fuel, technology, modifications of their original characteristics or date of start-up authorisation.
- The following standard concepts are used to calculate the specific remuneration for each category: income generated in the market, operating costs, and initial investment.
- There are regulatory periods of six years. At the start of each such period, most remuneration parameters used to calculate the specific remuneration may be reviewed, including: the 'reasonable' rate of return, estimates of energy revenues, operating costs, production hours or adjustments for deviations from the pool price. The estimate of energy revenues can also be reviewed in the middle of the six-year regulatory period. The only two parameters that are not subject to review are the regulated life of the asset and the standard value of the initial capital costs for that category of facility.
- The regulatory lives of the assets depend on the technology, ranging from 20 years (cogeneration and wind) to 25 years (CSP) and 30 years (PV). Once the asset has reached the end of its regulatory life, it is no longer entitled to the specific remuneration. If the asset is deemed to have earned its 'reasonable' return before the end of the regulatory life, then it is also no longer entitled to the specific remuneration.
- The concept of a 'reasonable' return is defined as a return of investment, before taxes, which is the same as the average yield of a ten-year Spanish bond plus an adequate margin. This return can be reviewed at the beginning of each six-year regulatory period. Of course, this leaves much room for debate about whether this really is a reasonable return on assets, given the risks.
- For existing assets earning a FiT/FiP, the 'reasonable' return, before taxes, was 7.398 per cent, which is three percentage points above a ten-year average of the ten-year yield on Spanish bonds. If the government considers that a standard plant for a specific technology earned more than this return before the change in 2013, then the new regime implies it will earn less than that return after 2013.
- The parameters for the new regime were defined in June 2014 but applied retroactively from 14 July 2013.

[38] The reform was initially introduced in a Royal Decree Law in July 2013 (RDL 9/2013), and then developed in subsequent legislation in 2013 and 2014. RDL 9/2013 introduced 'Urgent Measures to Guarantee the Financial Stability of the Electricity System'. It served as an initial part of a general reform to the energy system and established, among others, the principles of a new legal and economic regime for production technologies which use renewable energy sources, cogeneration and waste The principles contained in RDL 9/2013 were then reflected in a new law for the electricity sector: Law 24/2013, of 26 December. Royal Decree 413/2014 then established a new legal and economic regime for electricity production facilities using renewable energy sources, cogeneration and waste. Watson, Farley & Williams 2014.

[39] Ashurst 2014.

The new regime involved a cut of about 20-25 per cent in the annual financial support for existing renewable facilities and cogeneration. The precise reductions relating to the reform in 2013 are difficult to calculate because they depend on the specific asset, on how one defines the revenue in the base year and on what the revenues would have been under the old regulatory regime after it was replaced. To get an approximate idea of the impact of the change in the regime in 2013, we can compare the total financial support to renewable power, cogeneration and residues in the years before and after the change. Support for these technologies was €8.4 billion (2012) and €8.9 billion (2013), compared to €6.6 billion (2014) and €6.7 (2015). From 2013-2014, the change involved a reduction in support costs of about €2.3 billion.[40] The CNMC carried out a calculation to determine the difference between the support that was paid under the old regime and the amounts that would be paid under the new one. It also suggested that the difference between the two regimes was more than €2 billion per annum[41].

Older assets that were deemed already to have earned their 'reasonable' return were no longer eligible for any support. This especially affected wind power assets whose financial support fell steeply after 2013. However, these assets had at least enjoyed the benefits of the previous regime for a relatively long time. For newer assets like PV and CSP, the loss of expected revenue was substantial. Furthermore, the cuts in 2013 were additional to others dating from 2010, especially the reduction in the output of PV that was eligible for FIT. When considering economic harm, it is also worth mentioning the introduction of a 7 per cent tax in 2013 on all generation, including renewables.

There have been many challenges before the courts, in particular related to solar, wind and small hydro. Thus far, challenges brought in Spanish courts have been unsuccessful for the plaintiffs, with the government arguing successfully that the feed-in tariffs never guaranteed more than a reasonable return on investment. There are, however, over 35 international investment arbitration cases pending, mostly under the Energy Charter Treaty. The parties bringing the arbitration cases claim economic damages for retroactive adjustments to the regulatory regime. It remains to be seen what the outcome of those arbitrations will be. Although the reform was very unwelcome to investors, the government argued that it created a more predictable regulatory framework, in part because it was part of a wider set of measures aimed at limiting further growth of the tariff deficit.

On the positive side, the new regime appears to have introduced better operating incentives than the old one. For instance, in the old regime, a cogenerator with a relatively high marginal cost related to the cost of gas had an incentive to bid zero in order to generate electricity and earn the FiT. Sometimes this meant replacing renewable energy, whose marginal costs were very close to zero, and the curtailment of nuclear generation. Under the new regime, a renewable power station may now earn additional revenue by offering to reduce output in the market for ancillary services, whereas in the original regime the generator would always seek to maximize output. Of course, the social benefits of renewable power do imply that plants should generate whenever it is economic for them to do so and we are not aware that this is discouraged by the current regime.

The new regime has been heavily criticised for introducing new sources of risk, in particular through the potential for government to adjust the allowed rate of return every six years, to make automatic adjustments related to assumed energy revenues and operating costs, and to limit the ability to recoup the difference between forecast and outturn prices. For example, the government's overestimate of energy market prices for the period 2014-2017 means that realized returns for the standard installations will be below the 'reasonable' level because the adjustment to allowed future revenues will not reflect the full deviation.

The new regulatory regime applies not only to existing renewable assets but also to new ones. The government has announced its intention to hold a technology-neutral auction for 3,000 MW of renewable power in the first half of 2017. Investors will bid on the 'specific remuneration' incentive that they require to carry out their investment. An auction for 700 MW in early 2016 led to a specific remuneration of zero; investors were ready to rely entirely on energy market prices. Investors in the

[40] CNMC 2017a.
[41] CNMC 2016, page 93.

new auction expect the premium to be positive because the quantity to be auctioned this time is much greater and because the auction will have stricter guarantees to ensure that the bidders deliver the selected projects. However, comparing the prices from recent PV and wind auctions around the world with Spanish wholesale energy market prices, there are reasons to expect that the premium resulting from the auction will not be very high. One cannot rule out a repeat of the last auction.

Investors have indicated special concern about the risks that are built into the new system, and also about how the government will compare the cost of different technologies. The design of this sort of auction will not be straightforward, in particular because the government wants the auction to be consistent with the remuneration scheme that is currently in place for renewables in Spain. This would make the Spanish auction different from other auctions, where bidders compete to sell a block of energy. It remains to be seen whether the auction will truly be technology neutral; the devil is always in the detail and, in this case, the auction rules could well favour one technology over another.

5.1.d Conclusion

Both countries have experimented with different forms of renewables support and it is likely that future experimentation will continue – for Spain, at any rate - within the guidelines set by the European Commission. There is always a difficult balance to be struck between efficiency and effectiveness, and some difficult consequences to be considered in terms of the distortions on market operation. In many ways the approach which Spain is moving towards, based on investment support, seems to be less distortive to operations (although it is difficult to gauge its effectiveness at this stage or to judge the effects on overall incentives). It is also more in line with the overall EU approach to financial support, which generally favours 'investment aids' over 'operating aids'. There appears to be a case for further consideration of this sort of approach. While the Commission's preference for full harmonisation of systems of support in the interests of the Single Market is understandable, the approach they favour does not do enough to address the underlying market distortions arising from the support for a particular group of market participants and it cannot be regarded as the last word on the subject.

5.2 Embedded generation

5.2.a Introduction

The term embedded generation (EG) refers to generation that is connected to the distribution network, rather than to the high voltage transmission network. It is one of the distributed energy resources, which along with storage and demand response, are increasingly important sources of energy. (Sioshansi 2014) Some embedded generation is thermal plant, for instance part of a commercial or industrial CHP facility, or diesel back-up and peaking facilities. However, rooftop solar panels and local wind turbine facilities are increasingly common, leading to the general (and misleading) perception that embedded generation is by its nature low carbon.

The challenge is how to integrate embedded generation into existing electricity systems and markets. In part, this is a technical matter since distribution networks were designed to transport electricity from the high voltage network to the consumers, not to deal with flows related to embedded generation. Networks need to be redesigned to cope with fluctuation generation within the system, including the possibility of a reversal of flows whereby the distribution system is a net exporter to the high voltage network.

However, perhaps even more significant are the economic challenges of integrating embedded generation. There may be additional network investment costs to cope with embedded generation, but it is also possible that investment costs can be avoided in certain locations. The possibility of incremental costs or savings reinforces the case for providing the right investment incentives both for the distribution company and for the investor in embedded generation, and that the incentives be location specific. The distribution company should have an incentive to integrate the embedded generation in a way that minimises investment in distribution, but also in a way that is optimal for the system as a whole, for instance that allows embedded generation to compete in wholesale markets.

A second economic challenge is related to the operation of the distribution networks. Once investment has occurred, the distribution company and the owner of the embedded generation should have

incentives to minimise system operating costs, for instance by reducing congestion. This may be done through markets or regulation.

A third economic issue is related to the recovery of network costs and other fixed costs of the system. Under many regulatory models, consumers pay a volumetric charge for their electricity, and that price includes the cost of generation, transmission, distribution and other system costs. With embedded generation, the consumer's consumption from the system declines, but the system's fixed costs remain the same. In these cases, the result of embedded generation is to reduce the revenue earned by the distribution utility, which has to either absorb the loss or pass the costs on to the remaining consumers. The distributional consequence is that some consumers are able to avoid paying the system costs while others have to pay more. This is the origin of the 'death spiral' facing utilities since they cannot pass on their fixed costs to a dwindling number of consumers. The distributional impact is especially unsustainable when wealthier consumers are the ones who invest in embedded generation, leaving poorer consumers with higher costs.

The US was a pioneer in creating an entitlement to self-generation at a time when the technology was very expensive. In addition to volumetric pricing (which encourages consumers to generate their own electricity), regulators and policy makers offered a variety of incentives for embedded generation, including net metering (whereby the consumer paid for electricity only if the amount produced was less than the amount consumed, regardless of when it was produced and consumed), investment tax credits and attractive prices for excess energy sold to the system. These support regimes are now recognized as problematic and unsustainable, but governments have found it very difficult to withdraw them. Even if there are no such incentives to withdraw, it is difficult to design an efficient way to regulate embedded generation. A number of policy options have been introduced or proposed.

Firstly, introducing or raising the fixed element of the electricity tariff to reflect fixed system costs; this makes the incentive for investment in embedded generation more efficient. Since embedded generation typically relies on system backup, the fixed element of the tariff should recover at least the fixed costs of this backup, notably the network. However, this approach is politically difficult, especially if it involves an increase in the total cost for poorer consumers with lower consumption. Furthermore, by reducing the variable component of the tariff, it weakens the incentive to reduce consumption and to be more efficient in energy use.

Secondly, governments may be able to shift some of the costs of promoting renewable energy to the central budget, rather than recovering them through electricity tariffs. Electricity is often used as a form of tax collection to pay for subsidies for certain consumer groups, industries and fuel providers. It is also used as a way of financing public goods, such as renewable power, whose aim is to combat climate change and local environmental pollution. Optimal taxation suggests that public goods and potentially other policy costs are better financed through general taxation than through electricity tariffs. This reduces the incentive for inefficient embedded generation and the distributional risks associated with it, while encouraging investment in efficient embedded generation. It also lowers electricity prices, benefiting low income consumers and favouring efficient decarbonisation of other end-use markets where electricity competes directly with fossil fuels.

Thirdly, governments may aim to encourage more efficient operation of embedded generation and distribution networks, as well as fixed cost recovery. To provide incentives for embedded generation and other distributed energy resources to operate efficiently within the network, a part of the tariff may be dynamic, reflecting the extent of congestion in real time or in the near future. For instance, in some instances and locations, the distribution company may wish to pay the consumer to increase embedded generation or to use stored energy to reduce congestion. Meanwhile, consumers who choose to buy electricity from the network during periods of congestion would pay more. This dynamic element would not be sufficient to recover the full cost of the network, but it would provide efficient incentives to reduce congestion and shift some of the costs to consumers who were contributing to congestion.

5.2.b UK

The UK's response to the issues raised by embedded generation has had a number of dimensions – all have been complicated by an underlying and largely unresolved uncertainty about whether the

relatively slow development of decentralised generation in the past has been due to over-centralised system thinking. There have been strong policy pressures to favour embedded generation, partly because of the fact that such generation is increasingly from renewable sources and because the system has relatively tight margins. However, there has also been a counter-argument that those consumers who are able to invest in solar panels are likely to be better off; it would therefore be wrong to cross-subsidise them via the system as a whole, which increases bills for those least able to afford them. Furthermore, not all embedded generation is the same: some helps the system by reducing transmission or congestion costs; some adds extra cost because of its volume or location. Faced with these complex pressures, policy has tended to lurch towards taking a positive approach to encouraging embedded generation, to make up for past problems, then back again towards a more neutral stance.

The first manifestation of this ambivalence was in relation to feed-in tariffs for small scale renewables generators. Though not all such generators were connected to the distribution system, the general objective was clearly to favour smaller producers. The feed-in tariffs were much more attractive than the Renewable Obligation Certificates which were then available to larger producers (see renewables support section) and the arrangements had provisions to stop larger producers from breaking up their projects into a number of smaller ones. The tariffs provided secure long-term contracts for renewables generators of under five megawatts (MW), offering not only an export tariff but also a payment for power consumed on-site.

The tariffs were announced in 2008 and quickly proved over-generous, especially for small scale solar. As a result, uptake was much faster than expected and embedded generation rose very rapidly, causing both economic and technical problems. Within the first few years, a series of cuts were introduced (after some delays due to a challenge in the courts) and by 2016, tariffs had fallen by about 65 per cent (as had the rate of installations). Nonetheless, the rate of growth during the period when the higher rate FiTs had been available was extraordinarily rapid. Solar PV capacity grew roughly ten-fold between 2010 and 2016; the number of installations supported by FiTs grew to nearly 750,000; and, as noted above, generation rose 87 per cent in 2015 (DUKES 2016).

This growth led in turn to concerns about network charging arrangements. Ofgem launched a review of transmission charging arrangements for embedded generators in January 2016. Their concern was that these arrangements could 'over-reward embedded generation, which could be having an increasing impact on the energy system by potentially distorting investment decisions and leading to inefficient outcomes'. These effects arose from the nature of network charging in the UK (see network pricing section). Under these arrangements there are relatively strong signals about the cost of network investment at peak times via so-called Triad charges. Embedded generators are classified as 'negative demand'. It is therefore possible for those customers who bear such charges directly not only to avoid the Triad charges, but to receive payments from their suppliers for the charges avoided. For smaller customers, Triad charges are not separately identified in consumer bills; however, their supplier does bear the charges so the presence of embedded generators in their customer base will affect their incentives in a similar fashion.

Ofgem is concerned that this is creating a far from level playing field (Ofgem 2016c). One concern is the impact on historically incurred costs. Ofgem points out that,'The connection of an increasing amount of sub-100MW EG to the distribution system logically cannot help to avoid sunk/fixed costs of developing and maintaining the transmission network. The payments to Embedded Generation (EG) are an extra cost to suppliers over and above the payment of transmission charges to National Grid, and therefore an additional cost to consumers, to the extent that this cost is passed onto consumers. We are concerned therefore that the current level of embedded benefits may not reflect the actual benefits that sub-100MW EG provide to the transmission system and increase costs for consumers.'

The second main concern is over the impact on system expansion costs, given the huge growth in embedded generation. This is changing flows throughout the system (and sometimes flows are now 'reversed' – namely at certain times electricity flows up from those parts of the distribution system into the transmission network, especially in areas where PV generation is most widespread, as in the South West of the UK). This adds extra costs and uncertainties to system management but, given that the generation is intermittent, may not reduce the amount of capacity required in the network.

In addition, there are concerns over:

- the participation of embedded generators in the capacity market, further adding to the queries over whether it is achieving the right objectives (see Capacity Markets section). In the 2016 auction, the most successful bidders, as far as new generation was concerned, were embedded generators much of which was diesel or low efficiency (reciprocating engine) gas plants.
- system balancing charges, which embedded generators usually avoid, being treated as negative demand.
- transmission losses – as noted in the network pricing section, the CMA has pressed for more attention to be given to these costs. The question arises whether and how much embedded generators should pay towards such losses (or be paid for helping to avoid them).

As will be seen, these are complicated technical issues – and they are under review at the time of writing – so no overall judgement will be attempted here as to whether embedded generation is over-rewarded. But the story clearly underlines some of the risks in offering support for particular favoured forms of generation. Unless the right signals are being given and unless the implications have been thought through carefully, such support risks introducing new distortions and inefficiencies into the system, so increasing the cost and complicating the process of decarbonisation.

5.2.c Spain

Spain's approach to embedded generation is covered in legislation that for the first time regulates 'self consumption' facilities and in particular domestic PV panels. The new Power Sector Law (24/2013) is a general law, which includes general principles to regulate self-consumption facilities, which are then developed further in Royal Decree 900/2015, which was approved by the Government on 9 October 2015.

The Spanish approach must be understood in the context of the current access tariff structure, especially for small consumers and small businesses. As explained in Section 4.3, access tariffs include network charges to cover the cost of transmission and distribution, as well as levies, with the latter financing support for, *inter alia*, renewable energy, cogeneration, the tariff deficit and electricity supply in the islands. The access tariffs include a variable energy term (per kWh) and a fixed capacity term (per kW) whose value depends on the voltage connection level. Consumers also have the possibility of time-of-use tariffs. The tariff structure is badly designed: it recovers some fixed costs through the variable component, rather than through the fixed component. Furthermore, the tariff recovers a number of policy-related levies through the variable component even though they are not system variable costs. These two problems largely explain the government's decision to introduce what is often called a 'sun tax', which has had the effect of discouraging distributed generation in Spain. This is explained further below.

Chart 14 shows the breakdown of a typical household bill, whose complexity may help to understand why consumers complain that they do not understand their bills. Policy levies are light blue and network costs dark blue. Both the levies and the network costs are collected through the variable energy component of the bill (€/MWh) and through the fixed capacity component (€/MW/year). In addition, VAT (21 per cent of the bill) and the electricity special tax (about six per cent of the bill) are charged as taxes, although not shown in the graphic.

Chart 14: Breakdown of Spanish electricity bill

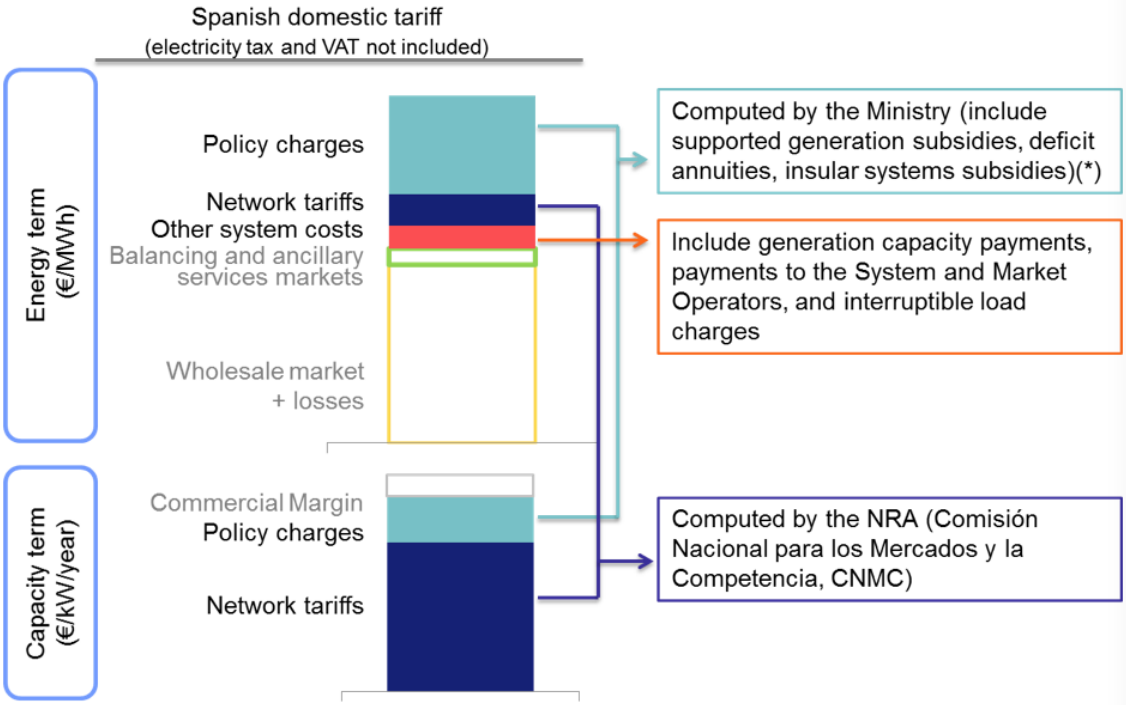


Figure 1: Domestic electricity bill breakdown.

Source: Aragonés et al 2016.

Most of the policy levies are collected through the variable component, while most of the network costs are recovered mainly through the fixed component of the access tariff. Collecting the network costs through the fixed charge makes economic sense because most network costs are fixed. But collecting policy levies through the energy component does not make sense because these levies do not reflect the variable costs of the system. As mentioned earlier, the government determines the access tariff and there is no publicly available information about the methodology used.

The most controversial measure included in the legislation is usually referred to as a 'sun tax' imposed on the owner of the embedded generation. In fact, the payments imposed on the owner are related to the consumer's overall demand and are designed to offset the loss of revenues (which are associated with the variable energy term) when a consumer decides to generate its own electricity. The payment appears to be a tax on self-generation, but in fact it is calculated so that all consumers (with or without rooftop PV) pay the same amount to recover network costs and policy charges. The only exception to this rule applies to consumers with demand below ten kW. All of the others have to compensate the system for the loss of revenues to the system associated with self-generation, specifically as a result of the reduction in their consumption from the system.

The ´sun tax' is a response to the two problems mentioned above related to the access tariffs. Firstly, the structure of the access tariff recovers a significant amount of fixed costs through the variable element of the tariff. As in other systems with volumetric charges, this gives consumers an incentive to self-generate even when there may be less expensive renewable energy available from the system. From the system's perspective, this is inefficient and also involves a loss of revenue. From the Spanish consumer perspective, self-consumption could avoid some of the fixed system costs, in particular the policy levies. Indeed, with the current tariff structure and in the absence of the 'sun tax', the residential consumer could save over 25 per cent of the final price in addition to avoided VAT and electricity tax. Even if there are savings to the system from self-consumption, notably a reduction in losses and possibly some avoided investment in the network, these savings would normally be significantly less than the loss of revenue to the system.

The government argues that the loss of revenue would require other consumers to pay more. In most countries, increasing prices for the remaining consumers is considered politically unrealistic and in any case unfair, especially for the poorest consumers; self-generation is practiced mainly by the wealthy with large houses/roofs, information and capital. In the US, where consumers choose to generate their own electricity, the progressive loss of revenue is sometimes referred to as a 'death spiral' for the utilities in the US, because as they raise their prices to collect system costs, their customer base disappears. In Spain, a more realistic concern is the reappearance of a tariff deficit, where recognised costs for regulated activities are less than the revenue collected to pay for them. In view of this, one possible solution would be to recover all of the fixed network costs and policy charges (levies) through the fixed component of the access charge. In that case, self-consumption would not need to be taxed to recover these costs. However, this does not solve the problem because consumers will have inefficient incentives to disconnect altogether from the system, or to find other ways to avoid paying the much higher fixed charge[42].

Second, the policy costs that are recovered through levies are very substantial, among the highest in Europe. Eliminating or substantially reducing these levies – for instance financing the cost of supporting renewable energy through general taxation – would eliminate much of the inefficiency that is currently built into the Spanish access tariffs and eliminate the rationale for imposing a sun tax. It would also lower the electricity price, benefiting all consumers, especially the poor, and encourage self-consumption only when and where it is economically efficient.

There are at least three other problems with the Spanish regime for self-generation. Firstly, the regime pays nothing for electricity injected into the system by most consumers who produce electricity on their premises. Electricity injected into the system should be rewarded to reflect the value of that energy to the system, just as electricity purchased should reflect its economic value.

Secondly, there is an important legal problem. The legislation requires consumers to install metering inside their premises (to measure generation) and grants the right to inspect them to distribution companies. Failure to do so implies very substantial fines. However, utility employees have no jurisdiction inside particular premises and cannot enter if opposed by the owner. This makes the legislation very difficult to enforce. If access tariffs were designed properly, with fixed network costs recovered through fixed access charges and policy levies eliminated or at least not included in the variable element of the tariff, there would be no need for this sort of inspection. In any case, if there is a need for the system operator to know how much energy is being produced, this measurement should be possible without entering the premises.

Finally, as a result of this legislation, the government has created great uncertainty and has undoubtedly discouraged investment, some of which would have been economically efficient. It has also created significant anger with the government and the electricity sector, which is already very unpopular with consumers. The new government continues to defend the general principles of the legislation and has not accepted the need to make the most important change, namely to reform the access tariff so that it reflects fairly the costs imposed by the user on the system, not the costs of financing a variety of public policies. The authors consider it necessary for Spain to revise its treatment of distributed energy resources to enable consumers to generate, store, consume and sell electricity efficiently. This will require changes to legislation to ensure that the tariff structure reflects accurately the associated costs of supplying that energy, that metering at the point of interconnection with the system enables consumers to buy or sell energy that reflects its economic value, and that policy costs recovered through electricity tariffs be reduced substantially if not eliminated. It is, however, necessary to recognize that this sort of reform requires rethinking many other policies and regulations, including how to recover policy costs that are removed from the tariff, how to address political opposition to higher fixed charges, and how to design regulations and markets to enable consumers to participate actively and efficiently in the management of the electricity system.

[42] Batteries are still expensive, but getting cheaper and cheaper. Again the problem has to do with the government wedge and the distortions it introduces. Batteries might save network costs, so network tariffs could be adjusted, but it is very hard to encourage efficient decisions on batteries as long as the wedge distorts price signals.

A special mention must be made of cogeneration[43], which is an important source of generation in Spain. It is sometimes embedded in the distribution network but treated the same regardless of whether or not it is embedded. In 2014, cogeneration accounted for almost six GW of generation capacity and 27 GWh of energy[44], over 80 per cent of which was generated from natural gas. Until the reform in 2013, cogeneration was remunerated through a feed-in tariff regime similar to the regime that applied to renewable electricity. The reforms introduced a regime based upon earning what the government considers to be a reasonable rate of return. This change significantly reduced annual revenues for cogeneration: estimates of the reduction range from €800 million to €1,000 million[45]. According to surveys by the industry lobby group (ACOGEN), this resulted in many plants shutting down and a 15 per cent reduction in electricity output[46]. Their primary regulatory proposals are:

- Financial support to renovate the cogeneration fleet so that the plants are more flexible, enabling them to participate actively in all markets, including for congestion management, ancillary services, balancing and capacity, in addition to energy.
- Network charges that reflect avoided costs and, in particular, that do not penalize electricity sales to nearby consumers or self-consumption of electricity generated on site.
- An increase in the 'reasonable' rate of return and consideration of the economic benefits derived from savings in primary energy as a result of cogeneration activities.

It is notable that ACOGEN argues that the survival of the cogeneration sector depends on their ability to compete effectively in the full range of markets and on not paying more for network access than the costs they impose on the system.

5.2.d Conclusions

Perhaps the main message from this section is the need to think clearly about the scale and objectives of support for particular types of generation. The UK experience suggests the wisdom of limiting support as far as possible to a single vector (for example the Feed-In Tariff) rather than providing it additionally through other means, such as through discounts in network charges. There are considerable risks, for instance of distorting the system in locational terms (getting generation in the wrong place); of creating equity issues (effectively requiring low income consumers to subsidise the wealthy); and of unintended consequences, for example encouraging embedded diesel generation, one of the unfriendliest energy sources in environmental terms when the overall objective is to protect the environment. Governments and regulators should try to get prices and incentives right, and consistent with overall policy goals, rather than simply trying to pick particular sources of generation for favourable treatment.

5.3 Demand Response

5.3.a Introduction

Demand response is in some ways a doubtful candidate for this paper. It is much talked about, certainly, and many experiments are under way but it has not really entered the mainstream of electricity markets. Neither Spain nor the UK offer clear lessons as to the way forward, although both countries have introduced policies that ostensibly encourage demand response. This section will therefore be as much about the reasons for the relative lack of progress as about particular policy models.

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[43] See details of Spanish cogeneration at the IDAE website: http://www.idae.es/uploads/documentos/documentos_Boletin_CHP_2014_web_a16285c9.xlsx

[44] Cogeneration contributed over 10 per cent of Spain's peninsular generation of 243 GWh. REE, The Spanish Electricity System 2014: Summary. http://www.ree.es/sites/default/files/downloadable/the_spanish_elecricity_system_2014_summary_0.pdf

[45] CNMC 2017a shows support for cogeneration falling from €1.9 billion (2012) and €1.7 billion (2013) to € 1.1 billion (2014 and 2015) and CNMC 2017b says support fell to €900 million (2016), partly as a reflection of reduced capacity.

[46] http://www.acogen.org/post/informe-encuesta-acogen16-y-hoja-ruta-2017-2020--29-09-2016.pdf

The case for more emphasis on demand response is widely accepted and does not need to be argued in detail here. In brief, electricity systems need to be kept in balance from minute to minute because of the difficulty of storage and network effects – when part of the system fails, the problem can 'cascade' across the whole system. Electricity security has therefore been regarded as a sort of public (non-excludable) good.

Balancing has been managed centrally by the use of flexible generation to meet demand, rather than by the management of demand, which has been regarded as insufficiently controllable in the short term and involving excessive transaction and coordination costs. There is also an economic problem – the value of electricity (usually defined as VOLL – the value of lost load) is normally much higher than the market price. Electricity is often regarded as a necessity, with very low short term price elasticity, and is a complementary good as it is used in conjunction with a piece of equipment to produce a service (for example lighting, powering appliances). Electricity costs are usually only a very small component of the value of the service provided. So, very high prices would be needed (and would need to be passed on in real time to consumers) for there to be a significant demand side response; it is usually cheaper to provide peak generation. In short, for both technical and economic reasons, the flexibility needed for balancing the system has generally in the past been sought on the supply side.

The need for a greater focus on the demand side arises from the 'new era' developments discussed in this paper - supply sources, like intermittent renewables, are becoming less flexible, while transaction and coordination costs on the demand side are falling rapidly, with the development of smart grids, meters and better controls. While system stability remains a public good which needs to be managed centrally, that is no longer as clear in relation to the reliability of individual supply. It is now quite conceivable for different consumers to have different levels of reliability if they so choose. Furthermore, the rapid decline in storage costs and the development of intelligent appliances means that it may now be economically viable for consumers to provide at least part of that required level of reliability themselves. In short, it is becoming increasingly conceivable for electricity security to be 'privatised'. In addition, there is now a clear environmental argument for more active individual or community involvement in demand management. It is noteworthy, for instance, that one of the most interesting experiments currently under way, Ireland's 'Power Off and Save', is being sold as much on the basis of the environmental benefits as economics.

But the obstacles remain substantial. One arises at the most basic level – what do we actually mean by 'demand response'? In a sense, demand response is a feature of all markets, via the familiar forces of supply and demand – not something defined as a product to be purchased centrally. From this perspective, the focus should not be so much on 'demand response' as a separate product but on reforming electricity markets so that they give proper signals about the cost of flexibility and incentives for consumers to determine the level of reliability they actually require rather than whatever has been set by some central authority (OIES 2016). That would then leave the requirements of system stability to be dealt with separately as a residual technical function of the system operator.

Even if that is regarded as too big a change to contemplate at the moment, there is still the question of what is the 'demand response' product we are talking about. Traditional definitions focus on demand shifting (namely away from times of system stress to other times) but in some countries, such as the UK, a wider definition is now generally used. After all, if the aim is to reduce demand at times of system stress, why does it matter whether that demand is shifted to some other time or forgone entirely? So demand reduction is included in the envelope, as explained below (taking us on to territory more frequently associated with energy efficiency). Furthermore, as noted below, the focus on shifting demand from peak times may no longer be the right one.

In practice, the definition is often even wider – for instance, the UK government has defined demand response as 'all actions that reduce demand from the transmission system at a particular moment in time', a definition which includes dispatchable distributed energy resources and storage[47]. In short,

[47] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/467024/rpt-frontier-DECC_DSR_phase_2_report-rev3-PDF-021015.pdf)

demand response can have a variety of definitions - the debate in different contexts may be focusing on different things and it may even be questioned whether the concept of 'demand response' is a useful one. Some countries, like the UK, have increasingly tended to use the wider (and even vaguer) term 'smart power', as discussed below.

Then there is the question of whether the economics stack up. Despite the changes referred to above, some of the fundamental problems remain (for example high VOLLs and coordination and transaction costs) and it may be that demand response will never be a major part of the system. However, it is difficult to know: analyses of today's economics may not provide definitive answers. Firstly, it may be the case that the economics look favourable on paper but the commercial case, in existing markets, is not there (Sustainability First 2014). Secondly, there is the problem that many consumers may lack the equipment or experience to engage in active demand management and therefore it will take time and behavioural adjustment to gauge the extent of their true interest.

A further complicating factor is that there are inherent problems when (as is usually the case at present) demand response is defined as a central system product to be procured on the same basis as other forms of flexibility. This approach is unlikely to produce innovation and will tend to be geared to traditional criteria. For instance, a system operator is likely to define its required flexibility product in terms of attributes like ramp-up rates, scale and duration of response and so on, all characteristics more relevant to generation than to demand response. Other actors may value other characteristics, of less relevance to the system operator. For instance, distribution companies may be particularly concerned about location (a reduction in demand on one side of a congestion point may reduce the need for new network investment). Consumers may be more concerned about time of day – happy to accept interruptions to supply during the day, but not in the evenings, for instance.

This leads to a further point – that traditional operators are generally still focused on times of peak demand, which are reasonably predictable. But in the new era, stresses may arise as much from less predictable, but potentially longer, reductions in supply as from increases in demand, so the ways in which time matters is taking on a new significance.

A further set of questions concerns the target market revolving around the fact that currently most demand response markets focus on large industrial consumers. This probably reflects the traditional focus on controllability, scale and low transaction costs. But it is not clear that these are the consumers with the lowest VOLLs (LE 2013). Big consumers generally use power in their production processes and they stand to lose output and income when supply is interrupted. Residential consumers, on the other hand, often have a considerable level of discretionary electricity use, which they do not mind forgoing, consequently lower VOLLs. The position is often clouded by the fact that many large consumers who are nominally engaged in demand response are in fact using back-up generation (as has been the case with the UK Short Term Operating Reserve, for instance). From the system operator perspective, this may be an acceptable way of reducing system stress, but there are likely to be economic and environmental disadvantages.

5.3.b UK

The general background is that, as in other countries, there is considerable interest in the potential of demand response but very little clarity about what is reasonably deliverable. For instance, a study conducted for the government by Frontier Economics (FE 2015) showed a very large theoretical demand side capacity (over 30 GW) as possible in future. However, the definition was very broad (for instance, it included distributed generation and firms with back up capacity) and the focus throughout the study was on the huge uncertainties so it probably provided more questions than answers. Another study, from the National Infrastructure Commission, on 'Smart Power' (NIC 2016) similarly stressed the potential of demand flexibility. But it saw such flexibility very much as a system product rather than a consumer product; it derived its estimates of the need for demand flexibility from present

and future decisions on the composition of generation, and it focused on the goal of a level playing field in the capacity market, arguing that:

'Providers of demand flexibility have stated that they are unable to access the UK's electricity markets on equal terms with generators, including the capacity market. The long-term goal for the capacity market must be to ensure a level playing field for the diverse technologies that can participate.' It argued that 'smart power' – embracing interconnection, storage and demand flexibility could save consumers £8 billion a year by 2030.

So, at a high level of analysis, the UK has confirmed the potential importance of demand response, without however really answering the questions raised in the Introduction above. At a more practical level, the UK's experience has been in four main areas, discussed below.

Firstly, in relation to the UK's new capacity market. As discussed in Section 5.4, this scheme was designed to encourage the construction (or retention) of conventional plants capable of providing reliable supply at periods of peak demand. In brief, it takes the form of an annual auction for capacity to be delivered in four years' time. Companies bid in at the price they need to stay open to generate electricity, or to enable new capacity to be built from scratch in time to generate. Demand response is in principle also able to bid into this market but (as discussed above) creating arrangements which suit both generation and demand resources is not easy. In the first two capacity auctions (2014 and 2015), for instance, demand response constituted less than one per cent of the successful bids. In 2016, demand response did rather better – nearly 1.5 GW was successful in the 'new build' category. However, as this was classified as 'unproven' and as it is uncertain how much of this total represents industrial consumers with back-up generation of their own, it is difficult to know how much to read into this figure.

The Government and National Grid have been seeking to make the arrangements more demand response friendly. For instance, as well as the main auctions, there is a special fenced off 'transitional market' for demand response (though for only 300 MW, as compared with a total market of over 50 GW)[48]. So far, therefore, experience with the capacity market is one of trying to learn by experience, underlining how difficult it is to create a level playing field for two fundamentally different sorts of resource.

Although not directly part of the capacity market, the Government is also experimenting with a Demand Reduction Scheme introduced at the same time and for the same purpose. They describe its role in the following terms:

'Electricity Demand Reduction (EDR) is a term that is used to describe electricity savings that are achieved through the installation of more efficient electrical equipment. For example, if an old electrical pump is replaced with a new more efficient electrical pump it will deliver savings by reducing the amount of electricity that is used at any time compared to if the original pump remained in operation. It is not Demand Side Response (DSR), where operation of equipment is reduced or the time of operation is changed. Savings cannot be directly measured because they represent the absence of electricity use. Instead savings are calculated by comparing energy use before and after a project, whilst making appropriate adjustments.

For the Pilot we are looking only at savings made during peak hours, for example between 4-8pm on weekdays, (excluding GB-wide Bank Holidays) between the beginning of November and the end of February.'[49]

As will be seen from the preceding description, demand reduction in this sense is somewhere between demand response (but not defined in terms of time shifting) and energy efficiency (but aimed at capacity rather than energy). In principle, this approach should be well targeted towards the challenges of a low carbon market, but as the description makes clear, this is still only a pilot (albeit

[48] https://www.gov.uk/government/news/government-announces-capacity-market-auction-parameters

[49] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/480548/EDR_Participant_Handbook_vpublication_30_November.pdf

two rounds have already taken place) and it would be premature to draw any particular conclusions as to its effectiveness. Certainly, the transaction costs seem high – as indicated above ad hoc calculations need to be made.

The second main area of UK experience is in relation to the Grid's Short Term Operating Reserve (STOR) and new balancing services introduced in response to the tight margins expected over the next few years before the capacity market gets under way. The STOR itself has long been part of the system; it is a sort of last resort back-up to deal with situations when short-term resources, either in the form of generation or demand reduction, are needed to balance the system, because of greater than forecast demand and/or plant unavailability. Wherever it regards it as economic to do so, the Grid procures part of this requirement ahead of time through STOR, as an additional back-up to the balancing market. Resource providers submit tenders against a list of criteria including response time, size and so on and successful bidders receive availability payments for making the service available, along with utilisation payments if it is actually used. A reasonable volume of demand side bids have been successful in these tenders (typically 1 GW or more) but most of the successful demand side bidders appear to be large industrial consumers, usually with back-up generation of their own which they can bring into operation when the service of reducing demand on the grid is being provided.

As part of its raft of responsibilities, the Grid also manages system frequency within tight limits. This sometimes requires very short term action (within seconds) for a relatively short period of time (say up to thirty minutes) for instance to deal with the sudden outage of a power station. As part of this function, the Grid operates a frequency response Frequency Control Demand Management (FCDM) scheme, which provides frequency response through interruption of demand customers. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting on site. This is a relatively specialised function and not directly the result of the 'new era' changes which form the background to this paper, but it does illustrate the range of services which the demand-side can provide. As noted below, the wider the range of such services, the greater the commercial opportunities which they present for customers. Although not strictly within the scope of this section, there is also increasing participation of battery storage in both frequency control and capacity schemes.

In addition, the Grid has recently introduced two new balancing services: the Demand Side Balancing Reserve (DSBR) and the Supplemental Balancing Reserve (SBR). DSBR is targeted at large energy users who volunteer to reduce their demand during winter weekday evenings between four and eight pm in return for a payment. (The DSBR is the demand side equivalent of the SBR itself, which is targeted at keeping power stations in reserve that would otherwise be closed or mothballed.) As the Grid explains 'these services will act as a safety net to protect consumers, only to be deployed in the unlikely event of there being insufficient capacity available in the market to meet demand'. They are a short term response to the expected tightness in capacity before the capacity market itself comes into operation and are intended to be discontinued.

There is also a new 'demand turn-up' scheme, aimed at large consumers and embedded generators, which operates the other way round (to increase offtake from the system at times of excess summer generation) but again it is too early to say whether this will be a permanent feature of the UK system.

The above schemes are run centrally by the Grid. They are mostly relatively new and, in some cases, are aimed at short-term problems as discussed above. A third area of experimentation in the UK takes the form of a series of experiments and pilots at the distribution level via schemes like the Network Innovation Competition and its predecessor the Low Carbon Network Fund (see Section 4.1). At present, however, these remain experimental and have not entered the arena of mainstream consumer pricing (where in any event, as discussed in the 'price interventions' section, the general trend is towards simplification rather than sophistication).

Finally, a fourth area of significance in the UK is the sometimes neglected area of network pricing. As noted in more detail in the separate section on this issue, the UK has relatively strong 'demand' elements in its network pricing system, in particular charges based on Triad use, namely a customer's demand during the three periods of maximum demand on the system as a whole. A customer who can reduce demand during these periods can make considerable savings. Indeed, for many

customers, this is currently the area which shows the greatest potential for securing a revenue stream from demand response.

As the outline above suggests, the options are quite complex and a number of service companies and aggregators have evolved to help consumers take advantage of schemes like the ones above and enable them to provide various services on a commercial basis via demand response. For instance, Flexitricity offers to help customers 'generate new revenue from your energy assets, cutting emissions and protecting core business around the clock.' It lists a series of revenue sources, including those listed above, along with the scope for more tailored 'over the counter' types of solution[50].

Overall, the picture in the UK is of extensive experimentation, some aimed at a specific short term problem of tight capacity margins; some at the longer term issues which the 'new era' challenges may throw up. While all sides agree that there are potentially substantial savings through developing the full potential of demand response, at this stage it is not possible to say that a clear way forward has been identified.

5.3.c Spain

In Spain, the only 'dispatchable' demand response is associated with interruptible demand by very large industrial consumers. The industrial consumer agrees to curtail demand at the request of the system operator, in return for financial compensation. For many years, these consumers paid an interruptible tariff, which was considerably lower than the price paid by other industrial consumers. For the past few years, Spain has been holding auctions for interruptible demand where large consumers bid the amount that they require to be subject to interruption.

Compensating interruptible demand is economically sensible, but the amounts that are paid in Spain are well in excess of the value of interruption in the current situation of excess capacity. The costs of interruptible demand in 2016 were approximately €550 million for less than 3 GW in a system with firm capacity well above the required reserve margin. Furthermore, by defining the interruptible service products in such a way that only very large consumers can participate in the auction, the payments are made only to those consumers. While this might have been understandable in the past, communication technologies would permit many smaller consumers to participate in the auctions if they were permitted to do so. Furthermore, interruptible demand is an alternative source of firm energy and could logically compete with energy from generation in a capacity or flexibility market.

Spain has introduced a regulated tariff (PVPC) for small consumers that does in principle provide the basis for non-dispatchable demand response by these consumers. The PVPC is for consumers with less than 10 kW of contracted capacity who choose not to buy in the market where prices and terms are freely determined. The PVPC includes three components:

- A fixed term including the annual network capacity charge and the annual commercialisation margin (per kW).
- A variable term related to the access tariff (per kWh).
- A variable term related to the hourly cost of energy, including the hourly wholesale market price (day ahead and intraday), the price for ancillary services and other service costs (capacity, interruptibility, system and market operations).

The consumer without a smart meter has no incentive to respond to hourly price signals because the meters do not register actual consumption. However, a consumer with a smart meter that is integrated into the commercial system has an incentive to adjust demand in response to the hourly prices that are published the day before.

There are a number of reasons in Spain why the PVPC has not yet led to a major change in demand patterns by small consumers, or to active demand response. Many consumers do not yet have smart meters that are integrated into the commercial system, and most of those who do are either not

[50] https://www.flexitricity.com/en-gb/

informed about how they could adjust their demand, or not interested in demand response (beyond adopting a tariff that is lower at night than during the day). Nevertheless, smart meters will be installed for almost all consumers by the end of 2018. This will offer some potential for aggregators who can see an opportunity to exploit the market for demand response, especially in combination with storage that would enable consumers to buy electricity when prices are very low and store it to use when prices are higher.

5.3.d Conclusions

When electricity markets were first liberalised, the demand-side of the market was virtually ignored. The result was a market design and rules that corresponded to very large generating sets and where gas and coal-fired power stations set marginal prices. Today, technology allows for a much more active demand-side, both dispatchable and non-dispatchable. However, market design and regulations are not designed to take full advantage of this alternative set of demand-side resources.

The UK has been experimenting with new market mechanisms and regulations to encourage demand response, including through capacity markets. Although UK experiments have not yet unleashed a significant demand-side resource, they do at least help to start a process of development and some incentive to explore the potential of this route. Spain, on the other hand, has focused almost exclusively on paying for interruptible demand from large industrial consumers, but these payments appear mainly to be a means of subsidizing these consumers rather than a basis for promoting efficient demand response.

It is important to recognise the difference in the need for demand response in the two countries. Both have significant penetrations of renewables requiring flexible backup, so in principle demand response is valuable in each country. However, whereas the UK is currently facing a shortage of flexible thermal capacity, Spain has a much larger reserve margin, making demand response more immediately valuable in the UK than in Spain. This could easily change in Spain in the event of closure of coal and CCGT power stations, which suggests that Spain could learn from the UK and other systems where demand response has been more successful. One positive signal from Spain has been the introduction of smart meters along with tariffs that pass on the hourly wholesale prices and could be the basis for more active demand response.

The recommendation for both countries is to make the necessary adjustments to markets and regulations to enable demand-response to play a greater role. In the short term, this would involve integrating large industrials and smaller electricity consumers (for instance via aggregators) in wholesale (and distribution) markets for capacity, energy and ancillary services. In the longer term, however, it is likely that more fundamental market redesign would be needed to give consumers and suppliers the right signals and incentives. The changes in customer behaviour and expectations implied are profound and are not likely to happen overnight. A process of discovery (of consumer preferences), development (of new supply chains) and experimentation (with different approaches to the issues) will have to take place before the true potential of the demand side resource can be established.

5.4 Capacity Markets

5.4.a Introduction

The impact of liberalisation on power sector investment was always a contentious area, even before the ‘new era’ challenges emerged. In 2003, for instance, a report by the IEA noted that ‘Governments have remained concerned about the adequacy and composition of power generation investment in a liberalised market.’ (IEA, 2003) A year later, a study by the Union of the Electricity Industry – Eurelectric – concluded that, ‘Since the liberalised market is still only a few years into the investment cycle, it can fairly be said that the “jury is still out” concerning whether liberalisation has yet proved, or will prove, to be a sustained success’. (Eurelectric, 2004). Some years later, in ‘Lessons learned from Electricity Market Liberalisation’, Paul Joskow, one of the pioneers in this field, used the same expression, saying that ‘the jury is still out on whether competitive power markets can stimulate levels of investment in new generating capacity in the right places at the right times consistent with political preferences’. (Joskow, 2008 p 26)

As the wording of the comments above partly reveals, there are two distinct aspects to the problem:

Political acceptability – for instance, the IEA refers to the 'adequacy and composition' of investment, while Joskow refers directly to the 'right' sort of investment to meet political preferences. There has always been an element of confused thinking here – why should markets be expected to deliver the sort of investment politicians happen to want (unless, of course, the market design contains specific incentives for this purpose)? Markets are a form of discovery mechanism, not just an instrument for delivering specified policy outcomes at the lowest cost.

Market design – there is also an underlying question as to whether the risks involved in investment in energy-only markets are so great as to prove a disincentive to investment. Energy-only markets (kWh or MWh based) normally reflect short run marginal costs (srmc) only – it is not necessarily clear how the costs of investment will be covered. In principle, it is possible to do so, provided prices can rise sufficiently far above srmc during periods of shortage to cover capital costs. The problem is that such periods (and the prices generated) are not entirely predictable in themselves. Furthermore, since they are likely to be both brief and rare, there is a serious risk that investment costs will not be fully covered, at least in the short to medium term. There is also a political risk – since prices will on occasion have to rise very significantly above the level of short run costs at any particular time, there is always a perceived risk of political intervention to prevent the (apparent or real) exploitation of market power. In other words, there is a potential problem of 'missing money' (OIES 2016a).

For these reasons, some jurisdictions introduced capacity mechanisms or payments of various sorts to provide investment incentives, particularly during the early stages of liberalisation, when experience of how markets operated in practice was limited (for instance in the UK Power Pool in the 1990s). However, not all systems involve such payments – the UK dropped its formal capacity mechanism when the New Electricity Trading Arrangements were introduced in 2001 and the EU Single Market in electricity is based on a day-ahead kWh price. At first, at any rate, capacity mechanisms were the exception rather than the norm in Europe.

But with the emergence of the 'new era' challenges, the issue has had to be revisited in many countries. The initial response was to introduce a market for CO_2 emission allowances. The theory was that the internalization of the cost of emission allowances would increase the cost of electricity produced with fossil fuels (especially coal) and thereby favour decarbonised energy sources. At sufficiently high prices for carbon emission allowances, coal would be displaced in the merit order by less carbon intensive sources of energy, including natural gas, nuclear and renewables. If the expected price of these allowance prices were high enough, investment would favour the lower carbon alternatives. In practice, emission allowance prices have been too low to have the desired effect in the merit order, and have been too uncertain to influence investment. The absence of political credibility with respect to the willingness to establish and maintain high emission allowance prices has made the mechanisms that support these prices almost irrelevant. This has led governments to intervene to achieve the decarbonised mix that they sought, arguing that the 'market' was not delivering it. Ironically, the intervention in investment decisions contributed to the lack of confidence that investors had in the ability of the market to finance investments.

These challenges of the new era affect both of the aspects described above:

- Political acceptability now involves much more specific demands, for example for the construction of a certain amount of low carbon generation, often of a specified type. Markets operating freely cannot be guaranteed to deliver the precise outcomes which politicians are aiming for. Interventions, like Feed-In Tariffs and Renewables Portfolio Obligations, distort the markets, but are considered necessary to incentivise the 'right' sorts of investment.
- This in turn complicates the market design issue. While the new investments are 'right' from a political perspective, they are not necessarily 'right' from a market perspective. Adding large amounts of subsidised intermittent zero marginal cost plants to an srmc market creates major strains, making it even more difficult to justify investment in conventional plants – which remains necessary, however, if system security is to be maintained (OIES 2016a).

The problems were compounded by the impact of the 2008 recession, which led to declines in electricity consumption – a sort of 'perfect storm'. Fossil fuel plants are now operating for fewer hours (because the new sources have priority) at a time when the market price has also been falling. Generators have been losing money, conventional plants, which are often very new and efficient, have been closing and new investment has not taken place. (OIES 2015b).

The impact depends on the country concerned. Some (like Spain) have rules in place which prevent, or at least complicate, the closure of stations which are no longer profitable. Some (like Germany) have extensive interconnection capacity and provided the interconnected group of countries agrees not to intervene when price spikes occur (as they have done via the Joint Declaration for Regional Cooperation on Security of Supply[51] to which 12 countries in the region have subscribed), this 'dilutes' the national problem, reducing the need for capacity mechanisms to remunerate fixed costs. The Commission also prefers this approach – capacity mechanisms, especially when operated on a national basis, provide a separate source of income for eligible generators, so putting downward pressure on the price in the 'energy only' market, which the Commission wants to remain as the core of the EU Single Market. Indeed, the Commission is concerned that capacity mechanisms will be used to subsidise uneconomic capacity. However, many countries now see little option but to provide some sort of capacity mechanism for conventional plants and the Commission's emphasis is increasingly on trying to introduce some order into the process and to encourage a regional rather than a national approach to capacity mechanisms.

When it comes to the detailed design of capacity markets, many approaches are possible (and the possibilities overlap) so a full analysis will not be given here. Broadly speaking, the main choices are:

- Quantity based schemes under which a central authority defines the amount of firm capacity it believes to be needed for the country and provides incentives for the construction (or non-closure) of the required amounts of capacity.
- Reliability based schemes under which the authority defines the level of reliability a retail supplier needs to achieve and imposes penalties for under achievement. This in turn leads the supplier to build or contract for the required level of reliability, often through organised capacity markets.
- Strategic reserves where the authority contracts for a quantity of capacity which is not to participate in normal market operation but can be brought into operation in situations of severe market tightness (for instance, as defined by a particular price threshold).
- Price-based signals as in the original UK Pool. There was an element in the Pool price based on a combination of Loss of Load Probability (calculated according to an algorithm, based on market tightness) and Value of Lost Load (defined by the central authority – and set initially at £2/kWh, or about 100 times more than the expected market price), which provided a significant proportion of some generators' revenue (and was criticised for being open to gaming).
- Regulatory capacity payments that may be based on market conditions or be determined through an administrative process.

This section will not go into the arguments in favour of one or the other of these options (though it does look at the UK's approach and Spain's) but it should be noted that they all depend on initial determinations by a central authority (usually the government) designed to deliver a particular level of reliability by one route or another depending on the design chosen. As discussed in the Demand Response section, this may not in the long run be the best approach to the creation of a flexible and sustainable long-term market design.

5.4.b UK

After 2008, as the new challenges raised by the Climate Change Act were analysed, the UK moved fairly soon to set up a capacity market, despite having dropped its own version of capacity payments in 2001. The general arguments in favour of such a market set out above were compounded in its

[51] http://www.benelux.int/files/4414/3375/5898/Jointdeclaration.pdf

case by an impending tightness of capacity. A number of fossil plants were due to close in the mid 2010s under the Large Combustion Plants Directive (later the Industrial Emissions Directive) and many nuclear plants were also due to reach the end of their scheduled lifetimes (Rutledge and Wright 2010). There were also major environmental uncertainties – would new coal plants be permitted? Was the government prepared to give support for (as opposed to simply allowing) nuclear power?

In the late 2000s a number of reports – from Ofgem (Ofgem 2009, 42), the Climate Change Committee (CCC 2009, 9) as well as private consultants (for example Poyry 2009, 27) – drew attention to the strains these developments would impose on markets. Capacity margins were expected to decline (to less than zero without a capacity market) and Loss of Load expectations (without offsetting actions) to increase to up to nine hours per year (as compared with the government's target of three)[52].

After the General Election of 2010 the new government moved quickly, as one of its first measures, to announce a package of Electricity Market Reforms (EMR). Three of the elements of the package stemmed directly from the Coalition Agreement negotiated in the period immediately following the election (CA 2010): Feed-In Tariffs (FiTs) for renewables to replace the former Renewables Obligation; emissions performances standards for new power plants (designed to prevent the construction of unabated coal plants); and a floor price for carbon. A further element was added in the final package – capacity markets. The government took some time to consider what form such markets should take and after an extensive process of consultation, it decided not to go for a targeted or strategic reserve approach but for a market-wide system (specifically for all market participants apart from these receiving support under other schemes such as FiTs) designed as an adjunct to the energy only market[53].

The general methodology is that the government and Grid make a forecast of peak demand for a future period (generally four years ahead) and then translate that into a requirement for reliable capacity, using the three hours per annum Loss of Load expectation to help define the requirement. The Grid on behalf of the government then holds an auction for that amount of capacity (which can in principle come via demand response or storage as well as generation). Trading of the obligation is allowed until the point of delivery, when the providers have to commit to be available and deliver as needed or face penalties. There are also a number of more detailed design features for example on length of contracts and on the split between two sorts of player – 'price makers' (new power plants and demand response) and 'price takers' (existing plants). A 'descending clock' auction methodology is used (namely the price on offer decreases in stages until supply and demand match). Initially, the government started off with a benchmark price in mind in the form of CONE (the annualised cost of new entry, set at £47/kW (see OEF 104). The overall costs of the system are shared on a per unit basis among suppliers. (In addition, as noted in the Demand Response section, the Grid evolved a suite of shorter term balancing reserve options to fill the gap until the capacity market came into operation).

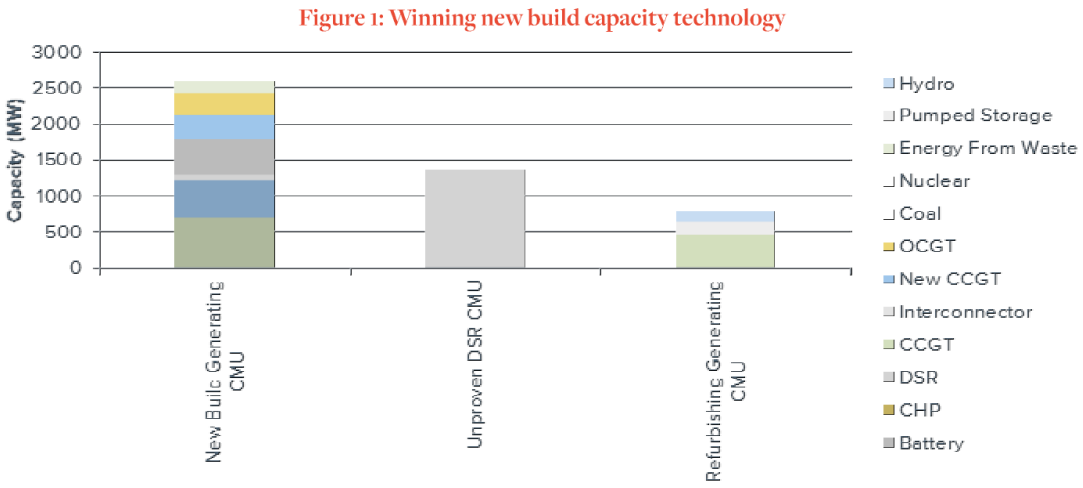
The first auction was held in December 2014 when 49GW of capacity was awarded contracts at a price of £19.40/kW. However, most of the awards went to existing capacity – just 5 per cent were new plants. Demand response was even less successful – less than 1 per cent of the total. Existing nuclear and coal plants, by contrast, were big winners. The total cost for the year of delivery - 2018/19 – was nearly £1 billion. The second auction, in December 2015, produced broadly similar results, though with a particularly strong showing from new diesel generators. The Interconnectors with Netherlands and France were also allowed to bid for the first time and received awards. Given the problems with demand response a special 'transitional arrangements' auction was held in early 2016, which proved slightly more successful than the generic auction, procuring 0.8GW at £27.50/kW.

[52]https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/335760/capacity_market_policy_presentation.pdf

[53] https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42822/3884-planning-electric-future-technical-update.pdf; https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/42795/2177-annex-c-emr-white-paper-consultation.pdf

In the third main auction in 2016, the government introduced a number of changes with the basic aim of encouraging new build, particularly of new CCGT capacity. In effect, the government introduced measures to push up the price – for instance, increasing the amount of capacity to be procured, increasing credit cover requirements for new generators, taking more account of the environmental costs of diesel generators and offsetting the Triad advantages of embedded generators. Overall, however, the measures had less impact than expected. The clearing price remained low (at £22.50/kW) and most of the winners (86 per cent) were still existing capacity, including 5.7GW of coal. Embedded generators, including diesel and gas piston engines, did best in the new build category. Only two, relatively small, CCGT plants (of around 300MW each) were successful – see Chart 15.

Chart 15: New build capacity securing contracts in capacity auction 2016



Source: EMR Delivery Body

It is difficult to say whether the system can be regarded as successful overall – the auctions themselves are still at a developmental stage and of course we have yet to reach the planned delivery year so they have not been fully tested in practice. In one respect only have the auctions achieved their objective: in keeping down costs of capacity procurement. Compared with the reference price of £47, both auction rounds achieved a clearing price of under £20 and in the third round, despite the efforts to get the price up to encourage new build, the price was only a little higher. But that is about as far as the successes go.

Some technical objections have been made to the arrangements, for instance to the 'descending clock' approach (Harbord and Pagnozzi 2014). There have also been criticisms of the amount of 'deadweight' involved as a result of including existing plants (for example the nuclear plants, which received awards, were very likely to have continued in operation, even without the need for capacity payments, given their low marginal costs). Many would also argue that the relatively poor showing of demand response is due to the fact that it did not face a level playing field. By contrast, embedded generation has probably been more successful than is really justified because in its case the playing field is arguably skewed in its favour. But the strongest objections have been on environmental grounds – the auctions have probably kept older coal plants in operation longer than would otherwise have been the case and have led to the construction of new diesel capacity, both outcomes which seem inconsistent with the overall objective of decarbonising electricity.

Perhaps the most fundamental issue has been uncertainty about the aim of the auctions. The original purpose of the system, as set out in 2011, was to create stronger incentives for investment in reliable capacity. It stemmed from the fear that investment in generation would not be sufficient to maintain security of supply without such a scheme. The aim was, at least implicitly, to encourage investment in CCGT plants – that was the reference plant chosen for CONE purposes as described above. At times, this aim became quite explicit. For instance, in her so-called 'reset' speech in 2015, Amber Rudd, then Secretary of State for Energy and Climate Change, said, 'it's imperative that we get new

gas-fired power stations built' and made it clear that she would redesign the capacity market in order to achieve this. (Rudd 2015). Against this background, the fact that the capacity auctions succeeded mainly in keeping older plants in operation (or in subsidising them unnecessarily), that they encouraged the construction of new diesel plants, and that they did little for demand response, all without actually doing much to deliver the prime objective (new CCGTs) looks like a considerable failure, especially from an environmental viewpoint.

The Department of Business, Energy and Industrial Strategy is now considering the arrangements for the next auction round in the light of these objections, for instance to bring in environmental considerations and to give more encouragement to the construction of new gas plants. But this brings into question the whole purpose of the exercise. The original idea of a market-wide arrangement was that it would be, as suggested above, a process of discovery, to establish, via a technology neutral auction, the cheapest way of maintaining security. But if the solution discovered by markets turns out to be unwelcome to governments, we seem to be back in the dilemma outlined above – it is not clear whether governments really want markets as such, or just ways of delivering their policy objectives at minimum cost. As those policy objectives get more complex and detailed, it gets more difficult to define a role for markets – arguably the better course (as discussed in the Demand Response Section) would be to try as far as possible to 'privatise' the policy goals and leave it to consumers to decide how best to meet them, leaving for central decision only those aspects which are truly market failures or public goods.

5.4.c Spain

Spain introduced capacity payments for conventional power stations, set at a level determined by administrative decision rather than markets, when it liberalised the electricity sector in 1998. As in other countries, administrative capacity payments in Spain supplement energy market payments. The capacity payments were originally paid to thermal, hydro and pumped storage generation capacity as a means of ensuring resource adequacy, but they are now primarily paid to CCGTs and to a lesser extent coal-fired plants, and cannot be considered technology neutral. In 2015, generators received €438 million under these arrangements.

There are several schemes that might be considered as capacity remuneration mechanisms in Spain for conventional generation: the investment incentive, the environmental incentive, and the availability incentives:

1) Investment incentive. The stated objective of the investment incentive is resource adequacy. Eligible capacity includes new plants commissioned after 1998, which are mainly CCGT. Until 2012, the payment was €26,000/MW/y for ten years after commissioning. From 2013, the payment fell to €10,000/MW/y. However, generators whose capacity payments were due to elapse after 14 July 2013 were granted an extension of twice the period pending from that date until the original expiry date of their capacity payments. No investment capacity payments will be available for new plants under existing legislation.
2) Environmental incentive. The objective of this incentive is also resource adequacy. It involves financial support for plants where environmental investments have been undertaken to comply with the emission performance standards set in the Large Combustion Plant Directive (for example SOx scrubbers for coal units). The regulated payment is 8,750 €/MW for a ten-year period after the commissioning of the scrubbers. The system entered in force in October 2007 and was discontinued in July 2013. Units that were already receiving the payment continue to do so until completion of their ten-year period, but new units are not eligible for this remuneration.
3) Availability incentive. The stated objective is to provide incentives for availability during peak periods. This is a non-mandatory service and the system operator (REE) has to certify eligible capacity to provide the service. It was introduced in 2012, and must be approved annually.

International experience suggests that there are a number of advantages and some important problems associated with administered capacity payments. Firstly, policy makers like this model because it encourages a desired level of capacity investment while imposing mitigation measures (namely excess capacity) on the energy market to avoid severe price spikes. Secondly, capacity payments can be designed to reflect the remuneration that the regulator estimates will be required to deliver the targeted reserve margin and may be adjusted to reflect changes in real reserve margins.

Thirdly, this approach also allows the regulator to distinguish payments by technology and vintage. To the extent that these payments provide a steady revenue stream and more stable energy prices, they may reduce investor risk and thereby lower the costs of supply.

There are, however, four main disadvantages to these payments. The first is that the approach does not guarantee investment: if the payments are too low, investment will be inadequate. And if the administrative capacity prices are too high, there will be excess capacity, which is equally inefficient (and expensive). Secondly, these payments can introduce and perpetuate price distortions. If energy prices are depressed as a result of capacity payments to some generators, this could mean that other existing or new generators will require a capacity payment in order to recover fixed costs; the result is an increase in costs for the system. A further distortion exists when capacity payments are paid only to generators and not to the demand side, which is an alternative to generation. Finally, the administrative flexibility in setting capacity payments introduces risk for potential investors. However, this is more a reflection of investor perceptions of the government than on the payment model itself.

Spain's administrative payments reflect some of these pros and cons. During the period when the system was growing, capacity payments were a convenient incentive for investment in CCGT's, which provided an economic support for Spain's policy of expanding natural gas networks and increased use of natural gas. Furthermore, these payments were supposed to change to reflect the balance of supply and demand on the system, so the payment formula lowered prices as the reserve margin grew. However, in retrospect, too much firm capacity was built: demand stopped growing in 2007 and the peak has since fallen from about 45 GW to 40 GW. The over-investment can be explained by a mix of: unforeseen renewables penetration, a significant decline in demand related to the economic crisis post-2007 and more than a bit of 'irrational exuberance' that affected the whole economy. Furthermore, the integration of more than 30 GW of wind and solar capacity has contributed to the reserve margin and to a decline in energy prices. Strict adherence to the original capacity payment formula seems to have been abandoned and replaced by payments that the government considers sufficient to limit closures of existing thermal plants on the grounds that the latter provide firm energy, flexibility and the ability to resolve network constraints. In short, the policy is no longer related to encouraging new investment, but rather involves managing existing thermal capacity until it closes.

The total cost of capacity payments has fallen progressively, partly because the capacity payment per MW has fallen and also because the number of eligible MW has fallen. Most of the 26 GW of CCGT continues to receive compensation as 'investment incentives' and 'availability incentives', while some coal plants continue to receive compensation as 'environmental incentives'.

Companies have argued that they are not free to shut existing capacity. Closure requires the authorization of the system operator (REE) and that authorization can be denied on the grounds of security of supply. However, companies are reluctant to shut plant for a variety of reasons, not least the prospect that prices may rise. Indeed, if sufficient plants were to close, wholesale electricity prices would rise, increasing margins for the remainder. So evidently, from the perspective of any one company, it would be better if some other company would shut its plants first. Nevertheless, companies will be obliged to shut coal-fired plants if these plants do not meet the emission performance standards set by the EU's Industrial Emissions Directive. It is up to each company to decide whether to make the investment required to keep these plants operating, or to prepare for their closure (by 2023 at the latest). Without additional compensation to supplement revenues from the energy market, it is quite likely that some of the coal plants will shut before 2023.

It is unclear how long the existing capacity payments will last. The government's view appears to be that these payments are a relatively inexpensive way to ensure security of supply. This concern was especially pertinent in early 2017 because high demand due to cold weather and French imports, in combination with reduced wind and hydro resources, saw electricity wholesale prices reach levels not seen since the end of 2013.

There is one additional reason why the government finds the capacity payments convenient and will not be in a hurry to get rid of them: they have been used to finance other regulatory system costs. In recent years, the government has collected more money from consumers to pay capacity charges than was actually required. This surplus has been used to finance other regulated activities whose

collected revenues are less than their costs. For instance, in 2015, the capacity payments to the generators were €732 million and the revenues collected to make the payments were €1.2 billion. The surplus revenue collected in this way has enabled the electricity system to balance its accounts and avoid adding to the tariff deficit.

This capacity payment system will not work for new conventional power stations. If there is a need for new firm capacity and investors require additional remuneration outside the energy market, the government will almost certainly choose a quantity-based auction, following the latest guidance of the European Commission. At that point, most of the questions will be the same as those faced by the UK in the design of their capacity auction. However, if the latest European Commission proposals in the Winter Package are accepted, these auctions will need to include generation from other EU countries, as well as demand side resources. Furthermore, generation capacity with CO_2 emissions over 550 g/kWh (for example coal fired generation) would not be permitted to participate.

5.4.d Conclusions

With the growing penetration of intermittent renewables financed through out-of-market payments, energy-only markets no longer provide the necessary signals for investment. In particular, there is a missing money problem, in addition to many other problems. Although the EU has resisted the introduction of capacity remuneration mechanisms, arguing that energy only markets can work if they are allowed to, they have identified general principles [54] that should be adopted where these mechanisms are introduced. These include such criteria as that:

- Capacity mechanisms must be accompanied by appropriate market reforms (for instance the removal of price controls).
- The need for such mechanisms must be demonstrated.
- They should be fit for purpose (namely adapted to the specific problems faced by the system in question) and open to all comers.
- Prices for capacity should be set by a competitive process.

Of the two capacity remuneration payment mechanisms adopted in Spain and in the UK, the UK's quantity-based auction seems superior to Spain's administered payment mechanism to the extent that it makes greater use of market mechanisms. We think it is likely that Spain will adopt a quantity-based auction in future, either to finance new firm energy or to determine which of the existing plants will remain open. Following EU guidelines, these mechanisms should involve demand-side as well as supply-side resources, and be regional in nature.

Nonetheless, neither country can be said to have developed an entirely successful capacity payments system. Indeed, there are wider questions as to whether in the long run this approach is the right one; all of these remuneration mechanisms are essentially arbitrary as they are based upon the premise that a central authority should determine the amount of capacity that is required and often its mix. As discussed in the conclusion of the previous section, in the longer term a more fundamental market reform is likely to be needed which allows consumers, rather than governments, to drive the process.

[54] http://europa.eu/rapid/press-release_IP-16-4021_en.htm

Section 6 – Conclusions

This paper covers a large number of issues and specific conclusions have been drawn in the relevant sections; they will not be repeated here. No single message can in any event emerge from the discussion as to the 'right' way to undertake and regulate electricity decarbonisation. All countries are different; they face different challenges and have different starting points. They need to find their own way through the difficulties.

Nonetheless, the analysis in this paper suggests some pointers in three broad areas, which are likely to be of wider relevance for any country embarking on or engaged in the process of decarbonising its electricity sector. Those areas are:

- Overall governance – the UK's experience suggests that having a clear sense of direction, and a robust process of ensuring that targets are taken seriously by the political system, are important elements in developing an effective approach. Spain confirms this in the sense that the absence of direction explains the ineffectiveness of the response to the challenges of the new era. (Section 6.1)
- System optimisation – this is going to be a critical element in ensuring an efficient and low cost decarbonised system, but neither the UK nor Spain has made much progress in this area. Instead both are indulging in piecemeal interventions with the risk of unintended consequences and of one intervention simply leading to the need for another. (Section 6.2)
- Integrated approaches – one main reason for the problems identified in this paper is that the process of liberalisation has left many governments ill-equipped to develop the full depth of understanding and expertise required to deal with the issues. But the solution is probably not for the government itself to try to acquire all the relevant knowledge and capacity. That risks a return to all the problems of centralised systems – of an inflexible and blinkered decision-maker unable to cope with all the uncertainties which decarbonisation entails. The solution may lie in creating new structures which can combine expert analysis and understanding with a genuine engagement with consumers and communities. (Section 6.3)

6.1 Overall governance

Political systems are in general not well constituted to deal with climate change. It is a very long-term issue – the costs and benefits examined in the Stern Report, for instance, stretch centuries into the future. Emissions targets extend for decades into the mid 2000s, well beyond the lifetimes of most parliaments – indeed probably beyond the lifetimes of most parliamentarians. Furthermore, the costs and benefits of climate change are global and most of the impacts will not fall on Europe and European consumers but on people in other parts of the world and on future generations. This can make it difficult to maintain a political consensus on the need for action, or to identify useful results from that action, at least in terms of direct climate impacts. It is probably also one of the reasons why intermediate targets (like penetration of renewables) have been taken as the focus of attention and treated as key indicators. This is particularly the case at the political level although, as the comparison between the UK and Spain shows, good performance in relation to renewables is not necessarily the same thing as good performance in reducing emissions.

A further major timing issue is the long life cycle of most energy investments. Power stations have lifetimes in terms of decades or more – a nuclear station can easily take ten years or so to plan and construct, and then operate for forty or fifty years. In addition, the costs can be enormous. As noted in Section 3.1, the Hinkley Point C power station is due to be possibly the most expensive constructed object on the planet. Renewables investment tends not to be so 'lumpy' but it is still generally very capital intensive – that is, it involves very large sunk costs, exacerbating the risk that there will be insufficient return on investment if circumstances or government policies change. Consumer appliances tend to have shorter life cycles but consumer behaviour and energy consumption in

general are slow to change. They are to a large extent a function of the housing stock, energy delivery infrastructure, urban and transport planning and so on.

Not only are the time horizons long, making change inherently slow in nature, but there is also a fundamental difficulty. Because we are dealing with such a deep-rooted market failure, the incentives given by markets operating on their own are not sufficient to deliver the changes needed. In effect, investors have to commit their money on the basis of trust in government policy statements, rather than on directly analysable market factors. The credibility of governments and their commitment to policy goals is therefore crucial, but the track record of most governments is not good. This study has noted a number of abrupt changes of direction and removal of particular support schemes; furthermore, it is clear that many government policies have not been fully thought through. There are unintended consequences – collateral damage, as it were, for those who are not the immediate targets of the policies in question (for instance, the conventional generators who lost income and market share and faced higher risks as a result of support for renewables).

A further dimension of complication is that of uncertainty. No-one, not even governments, knows what the future holds. Some of the possible scenarios have been discussed above (in Section 4.1, for instance) but the range of options is enormous, whether for market structure, utility business models or consumer engagement with electricity (OEF 2016). Policy-making in this situation of uncertainty is enormously difficult – it involves balancing the need to set out a clear sense of direction against the fact that the destination is unknown.

There can be no single route through these complications which will work for all countries. However, the UK seems to have managed the difficult balancing act more effectively than most, at least as regards the overall emissions trajectory. While the specific solution adopted in the UK may not be suitable for all countries, the underlying principles are arguably of general application. Specifically the aim should be, so far as possible:

- To insulate climate change policy from short term political pressures.
- To set clear, binding long-term goals so that investors and consumers understand the emissions trajectory the country intends to follow.
- To base decisions as far as possible on technical advice from expert bodies.

6.2 System optimisation

This paper has been divided into separate sections for different topics and in normal circumstances such an approach could risk failing to provide an overview and understating the interactions between the various subject areas. However, one contention of the paper is that the topic-by-topic treatment is in fact an accurate description of both governments' policy-making. By and large, any sort of overview is missing. Rather, governments are coming up with responses to particular challenges more or less in isolation. To an extent, this is understandable – many of the challenges are so new that governments have little idea how to handle them in themselves, much less how exactly they could be integrated into an overall strategy. But the issue-by-issue approach entails risks; at some stage a more coherent framework will certainly be needed if the countries concerned are to avoid a significant misallocation of resources.

To take a simple example. In the future, because of the increasing penetration of intermittent generating sources, it will become ever more important to find the most efficient ways of meeting demand peaks. There are at least six different options, all of which are likely to play a part, as discussed below. But to get the right balance between them, and optimise the system overall, there will need to be either efficient market signals or an optimised strategic framework. Neither exists at present in either country.

The options for meeting peaks include the following:

- Central generation – the traditional route.
- Decentralised generation – as decentralised generation grows, it becomes ever more important to ensure that it is integrated into the system and that its potential role in system balancing is exploited to the maximum.

- Network reinforcement – this is likely to take on a significant role as distributed intermittent sources grow as a proportion of the total. Networks will need to be able to make optimum use of all the sources available at any one time and these will be widely distributed across the system.
- International interconnections – as noted in the Section 4.2, this is already a key means of balancing systems on a European basis; the UK and Spain have suffered from their low levels of interconnection.
- Demand response – growing in potential both because of supply side developments and increasingly smart systems on the demand side.
- Storage – technologies have been developing rapidly in recent years and costs have been coming down to near commercial levels. Both system level and consumer level storage are likely to be an important part of future systems.

However, at present, each of these options is subject to a different system of regulation and each therefore faces different incentives. Nor have they been integrated into any overall strategy.

- Central generation – is mainly driven by market forces as far as operation is concerned. However some systems, such as the UK, have also introduced capacity payments. There is no wider strategy underlying these capacity payments (as discussed in the capacity section above) – the UK government is not clear whether it wants specific sorts of capacity, or can accept market outcomes.
- Decentralised generation – growth of decentralised plant is driven to a large extent by support schemes, such as the FiT payments which incentivise much embedded renewable generation. The schemes are designed to meet carbon targets, not to optimise the system and minimise overall costs. Instead, as the cost containment section points out, they are subject to largely arbitrary overall expenditure limits and incentives to reduce costs in specific areas. Furthermore, as Section 5.2 discusses, embedded generation may be over-rewarded in other ways. There is at present no guarantee that it is being built at the optimum rate from an overall system perspective.
- Network reinforcement – is subject to regulation. The regulation is to an extent flexible (as discussed in the networks section) but still gives a largely guaranteed return on investment. There is also some encouragement for innovation but this is explicitly experimental. As noted in Section 4.1, there is no overall vision for the network of the future and a number of significantly different scenarios are conceivable.
- Interconnections – are also in practice usually subject to regulation, at least in the UK, though in a different form (mainly via the cap and floor approach, which helps underpin investment by reducing risk) and the regulator adopts a case-by-case approach to considering proposals. While there is general acceptance that more interconnection is needed, there is no overall strategy. Furthermore, like some other issues, this one requires an international approach for optimisation.
- Demand response – as described in Section 5.3, a number of experiments are under way with different approaches (some linked with capacity mechanisms, some with network regulation) and there is no clear picture of how large a role demand response will play in the future system or what form demand response will take. Nor do current wholesale or retail prices give adequate incentives for demand response, and neither government nor regulator has given a clear idea of how such price signals could be created (beyond hoping that the introduction of smart meters will enable greater resort to time-of-use pricing, which is unlikely to produce an optimum result if the 'broken markets' thesis is accepted).
- Storage – is not treated in a separate section above, mainly because so little progress has been made in policy terms in considering how to realise the opportunities thrown up by the reduction in technology costs. In practice, although some experiments with storage are taking place, for instance under the RIIO arrangements, it remains a largely forgotten area. Indeed, as noted in Section 5.3, there is no clear regulatory definition of storage; it is not treated as a separate service and faces significant regulatory barriers. For instance, current treatment of storage in the UK

regards it effectively as a consumer when power is flowing in, but a generator when power is flowing out, leading to the risk that it has to pay twice for network use. Similarly, there are a number of solar generators who could add battery storage so as to increase their ability to provide system services, but they have little incentive to do so as their FiT payments apply to all exports on a flat-rate basis and they would see little or no benefit from spreading their output across the day as a whole or concentrating it on peak periods.

In short, although all six routes can be used to meet the same objective of mitigating the problems of intermittency, and while one key challenge for the future low carbon system will be to find the right balance between them, policy and incentives in each area are being developed separately and on different bases. There is no level playing field for competition, so market forces cannot be relied on to produce an optimum result. But there is also no central strategy – national or European – based on an overall economic analysis of the optimum contribution from each source. It may be premature at this stage to identify the way forward in any detail, but the lack of any mechanism to ensure the right balance between different options and deliver an optimum system overall is increasingly problematic. It may be that some new body is needed to provide this central overview as discussed in the following section. Alternatively, governments might try to grasp the nettle of market and pricing reform in a more determined manner. But at present it is not even clear whether they intend to adopt one or other of these routes.

6.3 Integrated policy approaches

One possible conclusion from the two sub-sections above is that there is still a gap in the policy-making architecture. Some arrangement may be needed whereby:

- Particular policies can be analysed in greater detail so as to identify the possibility of unintended consequences.
- A more informed overall approach to policy can be facilitated by more attention being paid to system issues, such as the system optimisation problems mentioned in Section 6.2 or the sort of market reforms which will lead to a sustainable low carbon electricity market.
- Perhaps most importantly, serious examination can be given to the next stage of decarbonisation. Governments have hitherto focused on the decarbonisation of electricity but the process has turned out to be much more than the simple substitution of one set of sources for another. As attention starts to move to the next stages – the decarbonisation of heat and transport – the issues will get even more complex in themselves. Furthermore, there will also, almost certainly, be a much greater impact on consumer options and behaviour. Hitherto, decarbonisation has largely been a matter of upstream changes (in power generation). In future, changes will need to be made to the downstream as well (for example in residential heating options, or transport technologies). The risks of unintended consequences (for instance, the impact of electrification in these sectors on the electricity industry itself) will multiply and the need for a thorough examination of the options will increase.

At present, it is not clear that either government has access to the sort of analytical capacity described above. Even the Climate Change Committee in the UK, generally successful though it has been, is focused mainly on emissions trajectories than on energy policy making as such.

Liberalisation has in a sense compounded the difficulties of decarbonisation. With the withdrawal of governments from direct involvement in the energy sector there has been a loss of expertise and technical knowledge, leaving policy makers ill-equipped to address the difficult problems outlined above. But in our view, the answer is not to reverse the process of liberalisation and return to a centrally managed energy market. It would not only be very difficult, in these times of austerity, to establish the depth of analytical capacity which the process would require; it would also raise new risks. Centralised systems are not good at coping with the kinds of uncertainty described above. They inevitably tend to indulge in a sort of ‘group think’, with a relatively narrow focus and an undue confidence in their view of the future. Furthermore, they are also prey to political pressures of one sort

or another, contrary to the objectives set out in Section 6.1. So it is probably not ideal for governments to have the main analytical function, although, of course, in the end it is governments which have to make decisions. The aim would not be to change that responsibility in any way, but to ensure that government decision-making is fully informed.

Nor do we believe that giving the task described above to an existing body, like the energy regulator, is a satisfactory solution. As described in Section 2.3, the regulator tends to work best when its focus is clearly on economic and competition issues. The more its functions are complicated by the conceptually distinct goal of policy analysis and delivery, the less successful it is likely to be in its primary task.

We would therefore suggest that there may be space for a new body – a sort of energy agency or system architect, as described in Section 2.1. The goal would be to have a body broadly similar to the UK Climate Change Committee, but with a more specific focus, namely on the policies needed to deliver the outcomes which the CCC identifies as necessary to keep the country on track to its emissions objectives. Like the CCC, the body should be independent and outside the political process. Its recommendations should have weight and authority so that governments could not simply ignore them – for instance, they might have to justify any departure from the recommendations to national parliaments.

It is difficult to identify an exact precedent for the sort of body we have in mind. It would be somewhere between the US Federal 'Energy Advisory Board' (which, as its name suggests, is mainly advisory in nature) and the California Energy Commission (which has a number of functions in relation to policy delivery). It would be a permanent body with its own staff and analytical capacity (like the UK CCC); it would not directly advise government but inform the process more widely by its publications, outreach and status. Its task would be to examine the policies, institutions and market structures needed to deliver a low carbon energy system, and to make recommendations to government and parliaments. One of its key functions would be to engage consumers and communities in the process and ensure that its recommendations reflected their concerns.

In the end, however, it will be for each country to develop structures appropriate to its own constitutional arrangements and governance systems. But the main message of this study is that the 'new era' for electricity (and energy in general) has brought with it some unprecedented challenges and opportunities. There is no single way forward which can be identified for all countries; what is clear is that the unprecedented challenges bring along with them a requirement for imaginative and creative policy thinking. New approaches are needed for the new era.

Annex

Brexit and the EU Dimension

This study deals with two EU countries, the UK and Spain, so it may therefore surprise some readers that so little is said about the EU (other readers may be surprised by the fact that such great differences of approach exist between two countries within the EU and on the way to the goal of an Energy Union). There are two main reasons for the avoidance of EU issues:

- The first is that the authors and OIES colleagues have written extensively on the EU and Energy Union elsewhere (OIES 2015a, Buchan and Keay 2016). This study is already lengthy and it seems unnecessary to duplicate that material here.
- The second is that the focus of this study is comparative – to look at areas where there are differences of approach and see what can be learnt from these differences. Almost by definition, the areas where the EU has managed to harmonise policy are not fertile ground for such comparisons.

Nonetheless, there seems to be one unavoidable EU issue – what difference is Brexit likely to make to the picture presented in this study?

This Annex offers the authors' thoughts on the question – with the warning that they can only be tentative suggestions. At present, the outcome is unclear and it will be some years before anything definitive will emerge.

Overall approach to Brexit

Nonetheless, the overall outlines of the UK government's approach are reasonably clear. At the time of writing (February 2017) there are two firm points of reference – the Prime Minister's speech to the Conservative Party Conference on 5 October 2016 and her Lancaster House speech of 17 January 2017[55]. These make it clear that the dominant theme (as with the referendum debate itself) will be **sovereignty** – 'taking back control'. There are two key elements to the sovereignty issue – control over immigration, and removal of the jurisdiction of the European Court of Justice.

The Prime Minister has also made it clear that she accepts that the necessary outcome is that the UK will leave the existing trading arrangements with the EU, namely the Single Market, the Customs Union and the present free trade area (the European Economic Area, which extends free trade to a few countries on the EU's periphery like Norway)[56]. Of course, this does not mean that trade with Europe will cease – it will of course continue but probably at a lower level than would otherwise have been the case.

The UK's aim is to negotiate its own special free trade agreement, which may involve some version of the Customs Union in relation to particular sectors. Whether this is possible within the timescale for negotiations is uncertain, but there are reasons to think it will be difficult from the point of view of the remaining 27 states in the EU – the EU-27. They have a number of other objectives:

- Underlying principle and in particular the 'four freedoms' which as far as they are concerned underlie the concept of free trade. Since the four freedoms include the freedom of movement of people there could be fundamental objections of principle to a free trade agreement which does not include such provisions.
- There must be a price. A number of EU leaders have made it clear that in their view there must be a price to leaving or, more politely, that no state should be in a better position outside the EU than

[55] https://www.gov.uk/government/speeches/the-governments-negotiating-objectives-for-exiting-the-eu-pm-speech
[56] The distinction between these three configurations is real but not critical in relation to energy, for which tariffs are not a significant issue.

inside. No doubt a number of politicians' views are influenced by the fact that there will be elections in a number of EU countries in 2017 (Netherlands, France, Germany), and governments do not want to give more encouragement to Eurosceptic parties.

- No cherry-picking. Many EU politicians (such as the European Parliament negotiator Guy Verhofstadt[57]) have also made it clear that there must be no 'cherry-picking' – taking the good bits and leaving the rest, which is what the UK wants. EU membership is a package, not a smorgasbord; rights are inseparably linked with obligations.
- In any event, the EU seems to have little appetite for big trade deals. The Transatlantic Trade and Investment Partnership has run aground after years of negotiation; even the relatively innocuous Canada trade deal (the EU/Canada Comprehensive Economic and Trade Agreement - CETA) nearly foundered, after the better part of a decade of negotiation, following objections from the Walloon region of Belgium. It should be remembered that all 27 member states (and in some cases sub-national governments) would need to agree to a new UK trade deal – there are many pitfalls en route.
- Finally the EU is facing an existential crisis. The problems with the Euro, bank capitalisation, and resistance to austerity rumble on, as recent events in Italy remind us. More fundamentally, the Brexit vote and US election result may indicate a shift in opinion against the underlying spirit of the EU. In simple terms, the EU stands for an approach which is technocratic, rational, rules-bound and internationalist, while Brexit/Trump may herald an era which is populist, emotional, interests-led and nationalistic. Faced with this threat, the EU may well be much more concerned in maintaining internal cohesion than worrying about relations with the UK.

It therefore seems unlikely that an overall deal can be met within the two year timescale set by Article 50. Furthermore, even when an overall deal is reached, the implications for energy are likely to take some time to work out; the issues are complex but probably not at the top of the political agenda.

So there is a possibility that no deal will be reached for many years – and Theresa May made it clear that she would prefer no deal to a bad deal. If this were to be the outcome the normal expectation is that the UK would revert to World Trade Organisation (WTO) rules after the two year period. (In fact, things are not simple, even in this respect – the UK is included within the EU tariff schedule as far as the WTO is concerned; it would need to negotiate its own schedule when it leaves the EU). However, energy is a special case – the WTO says very little about energy. The main international agreement governing energy is the Energy Charter Treaty and it is largely 'soft law', specifically more about intentions and endeavours than binding obligations. So there are many uncertainties.

Nonetheless, there is little reason to expect a move to impose tariffs on energy trade – it is not clear that it is in anyone's interests to do so. The main direct issues will probably be in relation to **market structures, standards** and **regulation**. There may also be indirect consequences for the development of energy and environmental policy, and from possible changes in other areas, such as restrictions on the free movement of labour. These issues, and the implications of Brexit for the EU-27 in relation to energy, are discussed below.

Energy markets and security

In some areas (for example oil) Europe is part of a global market and Brexit is unlikely to make much difference. However, with gas and electricity, the European Union has been moving towards single, Union-wide markets with their own structures and regulations. The process is far advanced but not yet fully complete. For instance, in relation to the **Single Electricity Market,** although there is widespread 'market coupling' to link national markets, this applies mainly to the 'day ahead' market, and not yet to other markets such as short-term balancing markets. The UK is arguably not fully compliant at present with the EU's 'electricity target model' as it does not have a sufficiently developed day ahead market to provide a benchmark price as the model requires. It is unlikely to have much enthusiasm for

[57] http://www.bbc.co.uk/news/uk-politics-38810162

completing the process post-Brexit and will probably not be prepared to commit to future changes such as those arising from the new EU-wide market design proposals which came out in late 2016.

The likely outcome is that while electricity trade will continue after Brexit, it will, as with trade in general, be at a lower level than would otherwise have been the case, and the UK will probably not be fully integrated into the Single European Market for electricity. There is a possible model in the current position of Switzerland – it trades electricity extensively with the European Union but without any formal agreement to apply European rules (though it has been trying, since 2007, to negotiate such an agreement, but talks are on hold at the moment, partly because of the sort of sovereignty issues which are likely to arise in the UK case).

At a more technical level, cooperation is likely to continue in some form between regulators via the Agency for the Cooperation of European Regulators (though the UK might need to be content with observer status), and system operators via the European Network of System Operators.

There could however be problems in relation to **Interconnectors** with the rest of Europe**.** There are a number of proposals on the table for interconnection with the EU and Norway, particularly for electricity, where they are important for the Government's decarbonisation strategy. At present, as Section 4.2 points out, the UK has four interconnectors – one each with France, the Netherlands, Northern Ireland and the Republic of Ireland, with three more in progress (with France, Belgium and Norway), and a further five planned for the 2020s. But before they part with their money, investors want to see stable regulatory and judicial frameworks, and both are cast into doubt by Brexit in which the UK is freeing itself of the rules and the jurisdiction of the EU. All this may delay the construction of new interconnectors. This would create extra problems for the UK in meeting its decarbonisation targets, as discussed in Section 4.2.

Special cases – the home nations

There is a special problem in relation to **Northern Ireland**, which is part of the United Kingdom but also part of the All Island Electricity Market in Ireland – and well on the way to meeting the Target Model. Northern Ireland is likely to wish to continue this process as it is very reluctant to see borders of any sort with the Republic of Ireland. Northern Ireland is already outside the main British electricity and gas markets and this is likely to continue: anomalous though it may be, Northern Ireland will probably stay within the All Island Market and thus effectively within the EU as far as electricity is concerned.

Scotland will probably want to do something similar, namely to retain virtual membership of the EU in energy and other policy areas, but in its case the practical problems will probably make this non-negotiable, at least in the immediate future. There is however a big question mark over the longer term – preparations are under way for a possible second independence referendum. While many consider it unlikely that Scotland will move to full independence as long as the oil price remains low, this may provide a further level of uncertainty and complication in relation to the Brexit negotiations once they get under way.

Energy is of course a key issue in Scotland, much more important in relative terms than for the UK as a whole. It is not only a major hydrocarbon producer in the North Sea, but also has a very low carbon electricity system, dominated by nuclear power and renewables – though, like Germany, it is seeking to move out of nuclear. In many ways the politics of energy are both different from, and more significant than, the rest of the UK.

Product regulation and standards

Standards for energy using equipment (for instance, maximum power limits for vacuum cleaners) were occasionally a matter of controversy in the debate on the Brexit referendum. The UK will almost certainly not be prepared to accept Brussels regulation on an automatic basis, and would regard this as compromising its sovereignty. Nonetheless, UK manufacturers will no doubt want to continue to export to Europe and will thus probably press for equivalent standards in many areas (to keep out cheap competition from outside the EU). The likely result is a patchwork of regulation, most but not all in line with EU standards. The problem for Brexit Britain will be that it will be the European

Commission, and maybe EU courts, who will be the judge of what constitutes equivalence to gain access to the market of the EU-27.

Overall decarbonisation strategy

The implications for decarbonisation policies in the UK and EU were a frequent topic of speculation during the Brexit referendum discussions. However, there are unlikely to be direct impacts, at least in the UK (for the impact on the EU, see below). Contrary to what some of those arguing for leaving the EU were claiming during the referendum debate, most of the impetus behind UK strategy comes either from wider international conventions (like the Kyoto Protocol and the Paris Agreement), or from UK sources (and in particular the Climate Change Act 2008, discussed in Section 2) not from Brussels. As pointed out in Section 2, the UK is already well ahead of EU targets and they are not the driving force in policy. It is unlikely that the UK government will withdraw from these arrangements – for instance, after the referendum it confirmed its commitment to the 'carbon budget' for the late 2020s. We should not therefore expect any wholesale reversal of policy.

The UK will probably take the opportunity to be a bit more flexible post-Brexit (for example have less emphasis on specific renewables targets and more on the overall carbon reduction target). However, this would not be a fundamental change – it is the direction in which the EU is moving anyway, with UK support. The UK was already at risk of failing to meet its EU target of a 15 per cent renewable share in overall energy consumption by 2020, and, before the Brexit referendum, the UK had campaigned, successfully for national renewable targets to be abandoned after 2020. Other changes may be that post-Brexit the UK will no longer have to worry about European 'state aid' guidelines and will henceforth be legally free to subsidise whatever energy source it wants by whatever amount of money it wants. Whether it will have the financial means to do this is another matter, though in any competitive scenario with continental Europe the depreciation of sterling will help. And of course it will not be subject to Commission reviews of its energy policy. But these would all be minor tweaks in policy rather than a change of direction. Overall, there could be a loss of momentum in some areas and some shifts of emphasis, leading to a gradual but increasing divergence between UK and EU policy approaches – further complicating the market and trading issues.

An open question is whether the UK will stay in the EU's **Emission Trading Scheme**. The UK government could take the position that emissions trading is not something imposed on the UK, which in fact operated a national emissions trading system before the EU's version was launched, and because emissions trading is, in theory, an efficient market mechanism to get least cost decarbonisation rather than a piece of Brussels bureaucracy. Like many EU states, the UK has found the EU ETS a disappointment because of the low carbon price, but uniquely it has done something about this failure by instituting a national carbon floor price. However, the UK would reap dis-economies of scale by returning to a purely national ETS. Likewise, the EU would lose if the UK, currently the second largest carbon emitter and a major importer of carbon allowances from its fellow EU states, were to quit the system.

Implications of non-energy developments

There could in addition be 'spillover' from discussions in other policy areas. For instance, the UK, until recently the only large European state not to have a public investment bank of its own, is likely to lose access to funds from the European Investment Bank. Lending by the EIB between 2011 and 2015 totalled €29.1 billion, of which 28 per cent was for energy. Once Brexit happens, this will inevitably decline; Turkey, the largest non-EU recipient of EIB funding, received €2.3 billion in 2015, compared to the €7.8 billion that the UK got in the same year. There is a smaller amount of EU infrastructure grant money for Projects of Common Interest that the UK could lose. The UK could also say goodbye to some research funding; restrictions on the free movement of labour could lead to a loss of skills in sectors such as oil; the UK would be less well-placed to secure public procurement contracts in the EU (though freer to favour UK companies in UK government contracts); and so on. However, it is very difficult to gauge how significant such impacts might be – the UK government is likely to seek to use the negotiations to seek to mitigate any harmful effects.

Impact on EU-27

If the impact on the UK is uncertain, the implications of Brexit for the rest of the EU are even more speculative. While there have been some indications of the likely shape of the UK negotiating stance, virtually no consideration has been given within the EU to its own position, beyond the general statements of principle discussed above.

What can be said is that the UK has been influential in developing EU energy policy approaches, particularly in relation to liberalisation and climate change, while being resistant to any direct Commission control. With its influence removed there may therefore be shifts in emphasis (though probably not wholesale reverses) in relation to energy policy. In particular:

- **Energy security** The Energy Union discussions initiated with a proposal for common purchasing of gas, from Russia in particular. While that specific proposal is unrealistic, a greater degree of coordination between national positions may be possible after Brexit.
- **Carbon targets** The EU has prided itself on being a global leader in this area and it is unlikely that it will change direction. However it will face some difficult decisions in the wake of Brexit – the UK is in fact well ahead of the rest of Europe in terms of emissions reduction and is aiming to achieve reductions of over 50 per cent by 2030 as compared with the EU target of 40 per cent. If the EU wants to maintain its 2030 target, there will need to be difficult negotiations over the allocation of extra cuts – unless it can reach some sort of agreement with the UK to continue counting the UK's reductions.
- **Energy Union** An OIES publication (Buchan and Keay 2016) identified the problem of governance as one of the main obstacles to achieving a meaningful Energy Union. The UK has long been very resistant to any significant powers for the European Commission in relation to energy; it is possible that Brexit will actually facilitate progress.

Conclusions

The outcome of the Brexit negotiations remains highly uncertain and it is likely to be many years before the way forward is clear. In the UK at least, this is likely to inhibit investment in the resources needed to move to a secure low carbon system, particularly interconnectors with European markets. Despite the uncertainties, it is not likely that tariffs will be imposed on energy and electricity trade. However, there are likely to be increasing differences of approach between the UK and EU-27 in terms of electricity policy and market design. It is probable that the UK, like Switzerland, will technically remain outside the Single Electricity Market. While this will not prevent trade from taking place, it may be at a lower level than would otherwise have been the case.

Brexit is unlikely to halt the momentum of decarbonisation but in this area too it may lead to an increasing divergence between the UK and EU-27. Ironically, it may also facilitate Europe's move towards an Energy Union. But perhaps the main impacts will in fact be internal as far as the UK is concerned: Brexit is likely to lead to increased tensions between the Home Nations as each seeks to go its own way on energy (and on other issues). This will both complicate negotiations in the medium term and may in a wider sense threaten the unity of the United Kingdom.

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